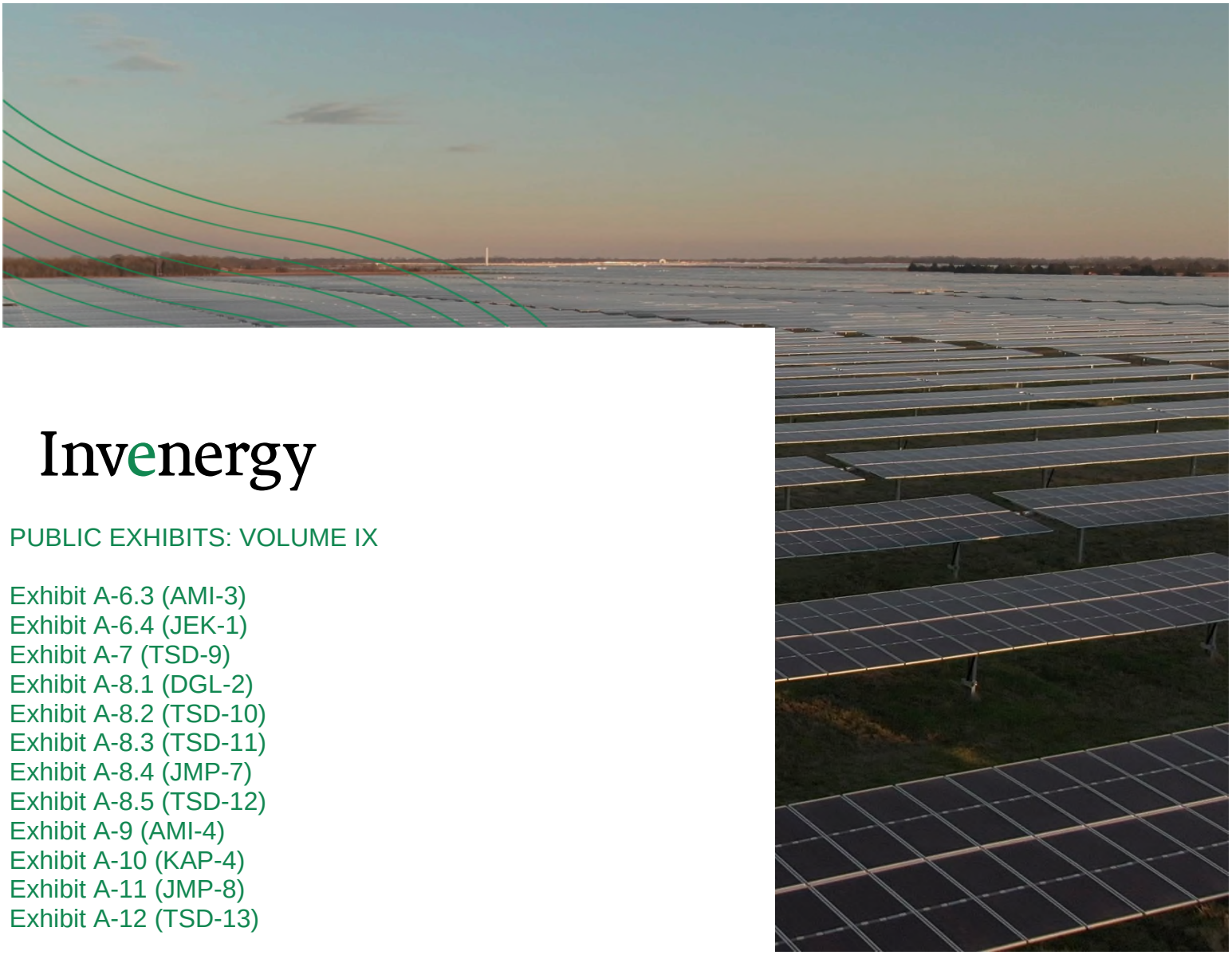

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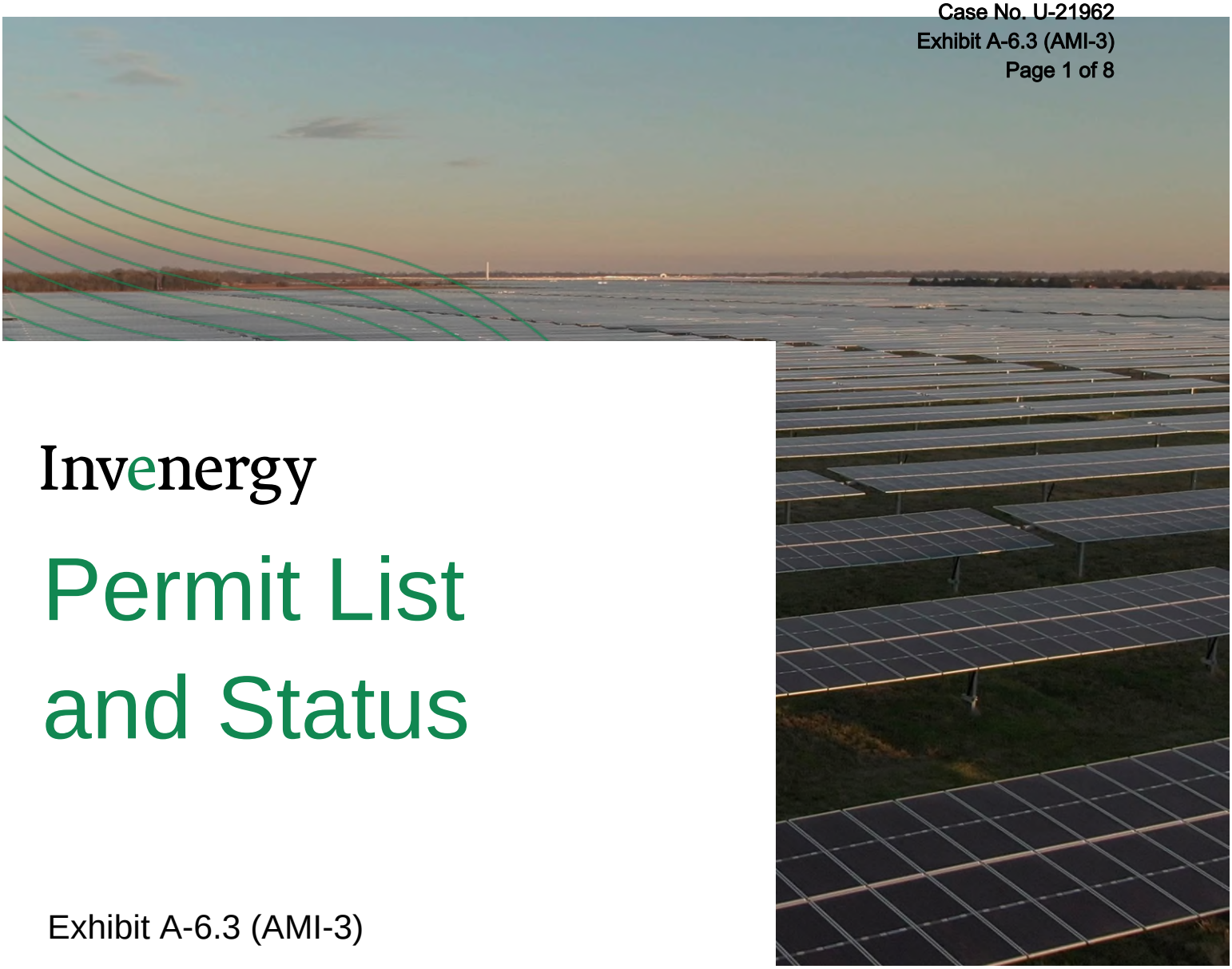
PUBLIC EXHIBITS: VOLUME IX

Exhibit A-6.3 (AMI-3)
Exhibit A-6.4 (JEK-1)
Exhibit A-7 (TSD-9)
Exhibit A-8.1 (DGL-2)
Exhibit A-8.2 (TSD-10)
Exhibit A-8.3 (TSD-11)
Exhibit A-8.4 (JMP-7)
Exhibit A-8.5 (TSD-12)
Exhibit A-9 (AMI-4)
Exhibit A-10 (KAP-4)
Exhibit A-11 (JMP-8)
Exhibit A-12 (TSD-13)

PREPARED FOR:

WASHTENAW SOLAR ENERGY LLC



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Permit List and Status

Exhibit A-6.3 (AMI-3)

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WASHTENAW SOLAR ENERGY LLC

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1.0 Introduction

Washtenaw Solar Energy LLC ("Washtenaw Solar") is proposing a 150 MW solar facility located on privately-owned land in Saline Township, Washtenaw County, Michigan (the "Project"). The Project is expected to require a number of permits beyond a certificate from the Michigan Public Service Commission. The commercial operation date for the Project is the third quarter of 2028 and the construction start date is expected for the fourth quarter of 2026. All permits are expected to be received before the start of construction. To date, no permits have been received. The permit list is included as **Appendix A**.

Appendix

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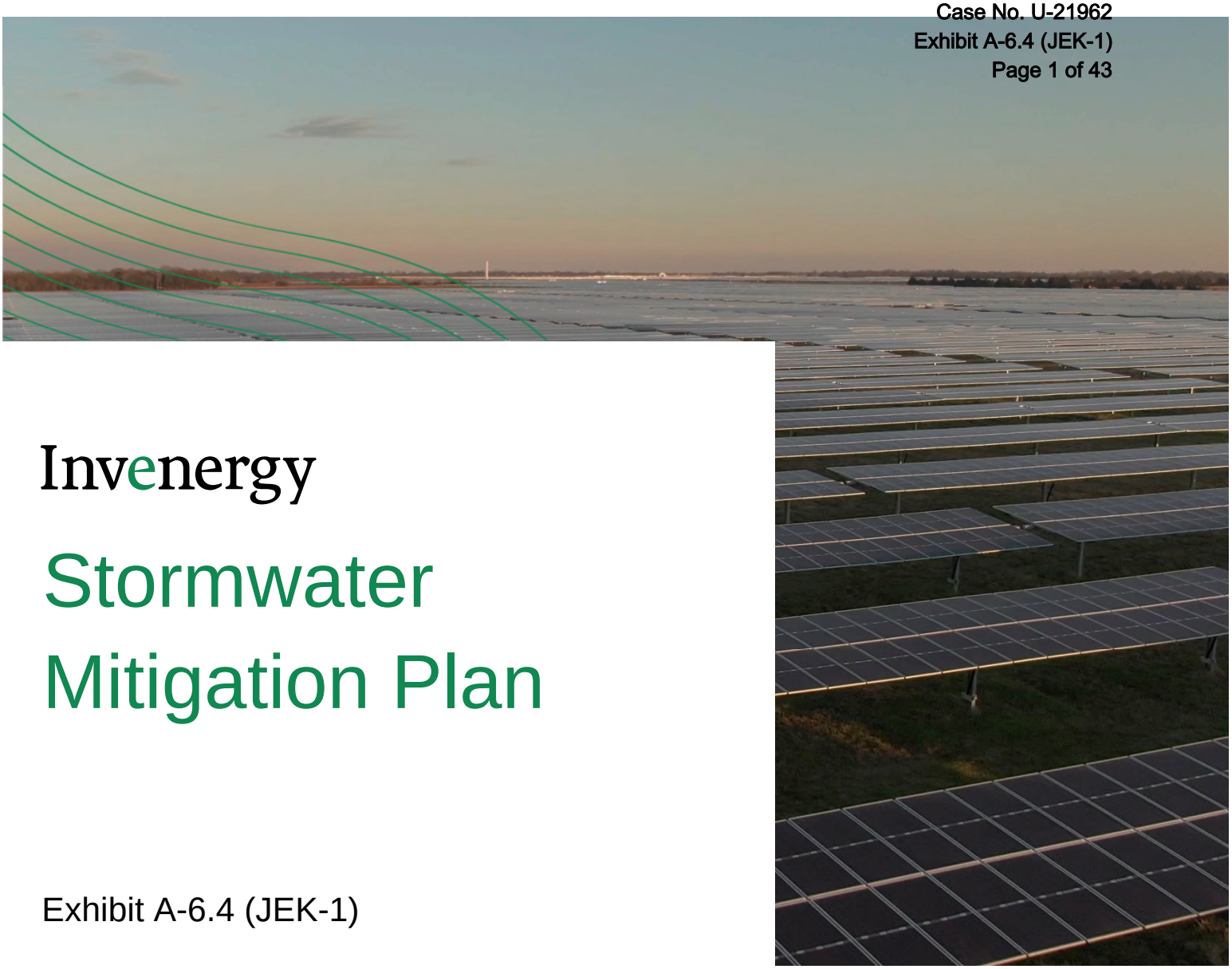
2.0 Appendix

Appendix A: Permit List and Status

Regulatory Agency	Permit/Plan/ Regulation	Triggers/Reason	Proposed Date of Application Submission	Expected Date of Issuance
State of Michigan				
Michigan Department of Environment, Great Lakes, and Energy ("EGLE") – Water Jackson District Office 301 East Louis Glick Hwy. Jackson, MI 49201 (517) 780-7690 Lansing District Office 1st Floor, S. Tower 525 W. Allegan Street Lansing, MI 48933 (517) 284-6651	Joint Permit Application – Part 303 Wetlands Permit	Permit required for depositing fill material, dredging or removal of soil or minerals, construction, operating or maintaining any use and or draining surface water in a regulated wetland.	Q3 2026	Q4 2026
	Joint Permit Application – Part 301 Inland Lakes and Streams Permit	Permit required for certain construction activities in inland lakes and streams, including dredging, filling, constructing or placement of a structure on bottomlands, constructing or operating a marina, interfering with natural flow of water or connecting a ditch or canal to an inland lake or stream.	Q3 2026	Q4 2026
	Joint Permit Application – Part 31 Floodplains Permit	Permit required to fill or grade in a floodplain, stream bed, or channel of a stream, or to undertake or engage in any activities on or with respect to land that is determined by the EGLE to interfere with the discharge or stage characteristic of a stream.	Q3 2026	Q4 2026
	Notice of Coverage – National Pollutant Discharge Elimination System ("NPDES") Permit	A Notice of Coverage is required for construction activities that disturb 5 acres or more.	Q3 2026	Q4 2026
Michigan Department of Transportation ("MDOT") University Region (Washtenaw County) 4701 W. Michigan Ave.	Oversized/ Overweight Vehicle Permit and Superload Permit (Act 300 of 1949, MI Vehicle Code)	Permit required when vehicles exceed size and weight limits for state highways.	Q2 2026	Q4 2026

Regulatory Agency	Permit/Plan/ Regulation	Triggers/Reason	Proposed Date of Application Submission	Expected Date of Issuance
Jackson, MI 49201 (517) 750-0401	Right-of-Way Construction Permit (Act 200 of 1969, Driveway, Banner and Parade Act; Act 368 of 1925 Encroachment Act; and Act 106 of 1972 Highway Advertising Act); Right-of-Way Permit	All work completed in the Right of Way including driveways, utility crossings and intersection improvements.	Q2 2026	Q4 2026
	Utility Coordination Permit (Act 368 of 1925)	Permit to Construct, Operate and Maintain Utility Facilities on Highway Right-of-Way. Work within the ROW which would include construction, operation, and maintenance of utilities, utility crossings, and intersection improvements.	Q2 2026	Q4 2026
County (Washtenaw County, MI)				
Washtenaw County Water Resources Commissioner's Office 705 N. Zeeb Rd Ann Arbor MI 48103 Drains@washtenaw.org (734) 222-6860	Drain Use Permit	Required to perform work or cross an established county drain or county drain easement.	Q3 2026	Q4 2026
	Soil Erosion and Sedimentation Control ("SESC") Permit	Necessary for new construction that disturbs 1 acre or greater or any soil disturbing activity within 500' of a lake or stream.	Q3 2026	Q4 2026
Washtenaw County Road Commission 555 N. Zeeb Road Ann Arbor, MI 48103 (734) 327-6642	Right-of-Way ("ROW")	To work within, occupy, maintain, establish a driveway or temporarily close a County Road ROW.	Q3 2026	Q4 2026
	Notice of Work	To notify the start or completion of work within the County ROW.	Q3 2026	Q4 2026
	Driveway Permit	Establishment of a driveway from a County road or ROW.	Q3 2026	Q4 2026

Regulatory Agency	Permit/Plan/ Regulation	Triggers/Reason	Proposed Date of Application Submission	Expected Date of Issuance
	Seasonal Weight Restriction Permit	Required for vehicles over 10,000 pounds operating on seasonally restricted roads.	Q3 2026	Q4 2026



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Stormwater Mitigation Plan

Exhibit A-6.4 (JEK-1)

PREPARED FOR:

WASHTENAW SOLAR ENERGY LLC

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1.0 Introduction

Washtenaw Solar Energy LLC ("Washtenaw Solar") is proposing a 150 MW solar energy facility in Saline Township, Washtenaw County, Michigan (the "Project"). Washtenaw Solar worked with Kimley-Horn & Associates, Inc. ("Kimley-Horn") to conduct a preliminary stormwater assessment and prepare a plan to minimize, mitigate, and repair any drainage impacts. This memorandum is included as **Appendix A**.

Washtenaw Solar and Kimley-Horn consulted with the Washtenaw County Water Resources Commissioner's Office ("WCWRC") in preparation of this stormwater assessment and mitigation plan (the "Plan"). This Plan addresses the guidance received from the WCWRC through that consultation process. **Appendix A** integrates the comments, feedback, and guidance that Washtenaw Solar received from the WCWRC.

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2.0 Stormwater Mitigation Plan

2.1 Assessment

Kimley-Horn provided a preliminary assessment of the Project Area and the drainage conditions therein. This assessment reviews soils, slopes, vegetation, and existing drainage patterns of the Project Area. The preliminary assessment is included in the Plan attached as **Appendix A**.

2.2 Minimization

The Project is not expected to have a significant impact on stormwater and drainage in the Project Area. To the extent that minimization measures are necessary, Washtenaw Solar expects to implement Best Management Practices ("BMPs") in compliance with the WCWRC Rules and Guidelines. Specifically, Washtenaw Solar will implement source controls to preserve the natural environment. The Project is also expected to minimize the use of impervious surfaces. As the Plan explains, "Per Hydrology Response on Solar Farms, published by the American Society of Civil Engineers (ASCE), with well-maintained vegetation underneath the panels, the solar panels themselves do not have much effect on total volumes of the runoff or peak discharge rates as the net increase in impervious ground surface is negligible."

2.3 Mitigation

With regard to mitigation measures, the Plan outlines the preliminary mitigation measures that Washtenaw Solar plans to use for the Project. The WCWRC BMPs for stormwater runoff controls are as follows, in order of preference: infiltration of runoff on-site; stormwater retention/detention facilities; conveyance off-site. The Plan anticipates using infiltration of runoff on-site (and the WCWRC's BMPs associated with Subsurface Infiltration Beds) and that stormwater retention/detention facilities are not required for the Project. A full description of the mitigation methods to be employed by the Project are included in the Plan attached as **Appendix A**. Drain tile repair will also be employed as a mitigation method, as described below.

2.4 Repair

Washtenaw Solar plans to reroute and repair existing drain tile that conflicts with Project infrastructure in the Project Area. The rerouting and repairing of on-site existing drain tile minimizes drainage disturbance and mitigates unnecessary site disturbance. All repairs and/or replacements to drain tile systems will be designed to meet the specifications of the Subsurface Infiltration Beds in the WCWRC Rules and meet the stormwater requirements specified by the WCWRC. Details on the planned repair and replacement of drain tile are included in **Appendix A**.

Washtenaw Solar does not anticipate damage to drainage systems; however, if any are to occur, Washtenaw Solar is committed to repairing and/or replacing all public and private drainage systems, including county or intercounty drains, damaged from the construction or decommissioning process. This commitment is codified in Section 2.3 of Washtenaw Solar's Proposed Agreement Regarding Conditions, see **Exhibit A-14 (TSD-14), Appendix C**.

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3.0 Consultation

Washtenaw Solar consulted with the WCWRC regarding the Plan and the Project. Washtenaw Solar integrated the comments received from the WCWRC with regard to the Plan into a revised version. The Plan is included as **Appendix A** and the initial plan, with WCWRC's comments included as **Appendix C**. The Plan addresses the guidance received from the WCWRC.

Summaries of consultations with the WCWRC are included below, detailing necessary permits, next steps, and associated timelines. Evidence of such consultations is included in **Appendix B**. For additional details regarding these consultations, please refer to **Exhibit A-4.4 (TSD-8)**.

First Consultation

Date: June 11, 2025

Venue: Email

Time: 1:49 p.m.

Participants: Matt Byrne, WCWRC, Stormwater Engineer

Jenna Elliott, Kimley-Horn, Civil Analyst

Kirsten Polen, Invenergy, Renewable Engineering, Senior Staff Engineer

Summary: Ms. Elliott contacted Mr. Byrne to share and receive feedback on Washtenaw Solar's Preliminary Stormwater Analysis.

Correspondence: This correspondence is included as **Appendix B**.

Permits: Please refer to "Permits" under the Second Consultation.

Next Steps: On **June 12, 2025, at 12:32 p.m.**, Mr. Byrne responded, asking for a map of the Project Area. He advised that, unless the Project Area is in a Washtenaw County drain easement, or if Washtenaw Solar plans to discharge into the Washtenaw County drains, the WCWRC does not have jurisdiction in Saline Township. On **June 20, 2025, at 10:24 a.m.**, Ms. Polen shared the KMZ files of the parcels within the Project Area. She indicated that Washtenaw Solar plans to avoid the Washtenaw County drains with any system facilities, but that discharging stormwater into the Washtenaw County drains may be unavoidable.

Associated Timeline: Please refer to "Associated Timeline" under the Second Consultation.

Second Consultation

Date: July 7, 2025

Venue: In-Person

Time: 12:00 p.m.

Participants: Matt Byrne, WCWRC, Stormwater Engineer

James Kampa, Invenergy, Civil & Structural Engineering, Director

Tyler Durgan, Invenergy, Renewable Development, Senior Associate

Calvin Carlson, Kimley-Horn, Engineer

Jenna Elliott, Kimley-Horn, Civil Analyst

Summary: Prior to the preapplication meeting, Mr. Byrne provided a markup of Washtenaw Solar's Preliminary Stormwater Analysis Memo. Mr. Byrne and representatives from Washtenaw Solar then met to further discuss the Preliminary Stormwater Analysis Memo.

Correspondence: The edited Preliminary Stormwater Analysis Memo is included as **Appendix C**. This correspondence is included as **Appendix B**.

Permits: Washtenaw Solar may be required to apply for a Drain Use Permit and a Soil Erosion and Sedimentation Control ("SESC") Permit.

Next Steps: If Washtenaw Solar is required to apply for these permits, it must prepare and submit the permit applications for review. Specifically, Washtenaw Solar must:

- Finalize Engineer-of-Record Site Plan drawings.
- Hold pre-application meeting with the WCWRC describing any Site Plan updates and confirming stormwater approach.
- Submit Engineer-of-Record Site Plan design drawings to the WCWRC for approval.
- Once Site Plan and stormwater design is approved by the County, submit formal Drain Use and Soil Erosion Permit Application to County.

Associated Timeline: A timeline of the next steps identified above is as follows:

- Finalize Engineer-of-Record Site Plan drawings in the third quarter of 2026.
- Hold pre-application meeting with the WCWRC describing any Site Plan updates and confirming stormwater approach in the third quarter of 2026.
- Submit Engineer-of-Record Site Plan design drawings to the WCWRC for approval in the third quarter of 2026.
- Submit formal Drain Use and Soil Erosion Permit Application to County in the third quarter of 2026.

Appendices

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4.0 Appendices

Appendix A: Preliminary Stormwater Assessment and Plan

Kimley»Horn
of Michigan, Inc.

MEMORANDUM

To: James Kampa - Invenergy

From: Calvin Carlson - Kimley-Horn & Associates, Inc.

Date: September 24, 2025

Subject: Washtenaw Solar – Preliminary Stormwater Assessment and Plan

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This memorandum provides a general overview of the existing and proposed conditions for the Washtenaw Solar Facility in Saline Township, Washtenaw County, Michigan. This preliminary analysis is intended to propose stormwater solutions that comply with the Washtenaw County Water Resources Commissioner (WCWRC) Rules and Guidelines. For the purpose of this Memo, the stormwater design will focus on three representative drainage areas on site.

Existing Conditions

The project area consists of approximately 2411.57 acres of farmland. The project area is located north of Hack Road and west of Maple Road, near Saline, MI. Rural residential areas are located north, south, east, and west of the site area. The existing topography for the site ranges from gently to severely sloped (0%-40%). The site generally flows from the northwest to the southeast. West of Macon Road, the site flows east; east of Macon Road the flow goes toward the southeast corner of the site, going into the North Branch Macon Creek which flows into the Macon Drain. Per available NRCS soil mapping, the on-site soils generally consist of loams, with approximately 76% being non-hydric soils and approximately 24% of the site was mapped hydric soils. The soils present on the site range from hydrologic soil group A to D, with much of the site considered Hydrologic Group B / D and C / D. An existing drain tile was identified and located for the project. The locations of the existing drain tile lines are shown in “Washtenaw Solar - Drain Mapping - 12.13.2024.kml” provided by Invenergy on January 3, 2025.

Post-Development Runoff

The proposed development will include PV solar module and tracker systems, gravel aggregate access drives, associated electrical inverter pads, underground electric cabling, and vegetative buffers. The project will be surrounded by a perimeter fence. The proposed area of disturbance is approximately 1407.28 acres. Solar panels will be mounted on piles and elevated above the ground as to preserve existing underlying soil and allow for revegetation. Gravel access roads are spaced out among several rows of solar arrays to maximize the amount of ground that will be ultimately revegetated. Per Hydrology Response on Solar Farms, published by the American Society of Civil Engineers (ASCE), with well-maintained vegetation underneath the panels, the solar panels themselves do not have much effect on total volumes of the runoff or peak discharge rates as the net increase in impervious ground surface is negligible. Rainfall that falls directly on a solar panel runs to the pervious areas around the surrounding panels. In the post-developed condition, the existing cultivated farmland will be converted to meadow vegetation to stabilize and provide year-round ground cover. This post-condition emulates the meadow which has a CN of 78 per NRCS TR-55. For the purposes of this memo and to be conservative with

our assumptions, the access roads are reflected in stormwater calculations as impervious with CN of 98 per NRCS TR-55. The concrete pads for the inverters will also be factored in as impervious area with a CN of 98. The proposed solar development will include a proposed drain tile system (or proposed infiltration bed system) to mimic the existing system and meet the WCWRC Stormwater Management Requirements described below.

WCWRC Stormwater Management Requirements

Per the WCWRC Rules and Guidelines (the WCWRC Rules), the post-construction stormwater management methods must treat the First Flush Volume, the Bankfull Volume Difference and the 100-Year Storm. On a call with Matt Byrne, the Washtenaw County stormwater engineer, on 1/03/25, solar farms are typically exempt from meeting the 100-Year Storm requirements. The First Flush Volume is defined as the first inch of rain from the entire contributing watershed as determined by the Rational Method while the Pre- and Post- Bankfull Volumes are calculated using 2-year, 24-hour storm event recurrence as determined by the NRCS Method. Per the WCWRC Rules, the Infiltration Volume is equal to the greater of the First Flush Volume or the Bankfull Volume Difference. For our site, the First Flush Volume will always be greater due to the large size of the drainage areas and the low percentage of impervious ground cover in each drainage area. Since the First Flush Volume is greater than the Bankfull Volume Difference, the entire First Flush Volume must be infiltrated. If the First Flush Volume cannot be infiltrated, then the entire First Flush Volume plus an additional 20% of the volume must be detained.

Runoff Calculations

The First Flush Volumes and Bankfull Volume Differences were analyzed for three representative drainage areas on the Washtenaw Solar Site. The First Flush Volumes were found using the calculations given in the WCWRC Rules. The First Flush Runoff Calculations can be seen below. The weighted runoff coefficient used in the First Flush Runoff Calculations, 0.5, is a conservative assumption that was made using the WCWRC Rules. The Bankfull Volume Difference calculations were found using the NRCS Method in HydroCAD. The HydroCAD report is shown in **Attachment A**. Although the existing land cover is Row Crop, the WCWRC requires that the pre-development landcover is modeled as either Good Cover Woods or Meadow, so we chose to go with Meadow. The post-development landcover will predominantly be Meadow, but there will be impervious areas for the road and equipment pads. Therefore, the difference between the pre- and post-development bankfull volumes will be the runoff that comes from the proposed impervious areas. The table below lists the runoff volumes found for the three representative drainage areas.

First Flush Runoff Calculations:

$V_{ff} = (1")(\frac{1'}{12"})(\frac{43560ft^2}{1ac})AC$

A = Total Site Areas (ac) excluding BMPs

C = Weighted Runoff Coefficient

Runoff Volumes				
Drainage Area (AC)	**First Flush Volume (ft^3)**	**Pre-Development Bankfull Volume (ft^3)**	**Post-Development Bankfull Volume (ft^3)**	**Bankfull Volume Difference (ft^3)**
11.97	21,726	26,746	28,662	1,916
1.84	3,340	4,138	4,138	0
25.23	45,793	55,321	59,154	3,833

Best Management Practices (BMP) Guidelines

The WCWRC Rules states that BMPs can be used to reduce both the amount of detention/retention required and to meet the First Flush Volume infiltration requirements. The applicable BMPs listed in the WCWRC for a solar farm are as follows: Infiltration Basin, Subsurface Infiltration Bed, Infiltration Trench, Bioretention Systems, Rain Gardens, Bioswale, and Vegetated Filter Strip. The calculations to find the Storage Volume provided by each individual BMP can be found in Section IV, Part C in the WCWRC Rules. The infiltration volume for the listed BMPs can be found with the equation, Infiltration Volume = Infiltration Rate x 6 hours x BMP Area. See Section V, Part D in the WCWRC Rules for more design requirements regarding Infiltration BMPs. The Total Volume Reduction Credit is the sum of the Storage Volume and the Infiltration Volume provided by the BMPs.

For purposes of these calculations, we will work to show that the First Flush Volume, or Infiltration Volume, will infiltrate into the soil with the proposed infiltration BMPs. By meeting the First Flush Volume Requirement, the site exceeds the Bankfull Volume Difference Requirement since the First Flush Volume is always greater than the Bankfull Volume Difference for the proposed Solar Farm.

Prior to final design, soil infiltration testing must be completed in BMP areas to understand the infiltration rates in these areas per the WCWRC Rules. For this exercise, NRCS Web Soil Survey data showing the hydraulic conductivity of the soil gave us a preliminary estimate of the soil infiltration rates. The saturated hydraulic conductivity in this area is roughly 0.4 in/hr, so we are assuming an infiltration rate of 0.4 in/hr.

Best Management Practices (BMP) Solutions

The purpose of this exercise is to identify post construction stormwater BMPs, described in the WCWRC Rules, that satisfy the Infiltration Volume requirements and minimize, mitigate and repair impact to the existing site and existing drainage patterns. County code typically has private developments employe permanent detention basins as site BMPs. However, construction of permanent basins would create unneeded soil disturbance and damage to existing drain tile infrastructure. Based on Alternative BMPs found in the WCWRC Rules, Subsurface Infiltration Beds (described below) offer a solution to stormwater requirements without implementing full size permanent stormwater basins. As part of the proposed solar design, existing drain tile that conflicts with project infrastructure will be rerouted and repaired throughout the project area. The rerouting and repairing of on-site existing drain tile minimized drainage disturbance and mitigates unnecessary site disturbance. This plan shows that the proposed drain tile on site will be designed to meet the

specifications of the Subsurface Infiltration Beds found in the WCWRC Rules and meet the stormwater requirements specified by the county.

Subsurface Infiltration Beds

A subsurface infiltration bed can be used retain and infiltrate stormwater runoff. See the diagram below for an example of what the infiltration bed can look like. Exact dimensions, materials, and details will be provided during the design process. The volume reduction calculations can also be seen below. Section V, Part J in the WCWRC Rules contains more information on the design requirements for subsurface infiltration beds.

Infiltration Volume Calculations:

Infiltration Volume = Bed Bottom Area x Infiltration Design Rate x Infiltration Period

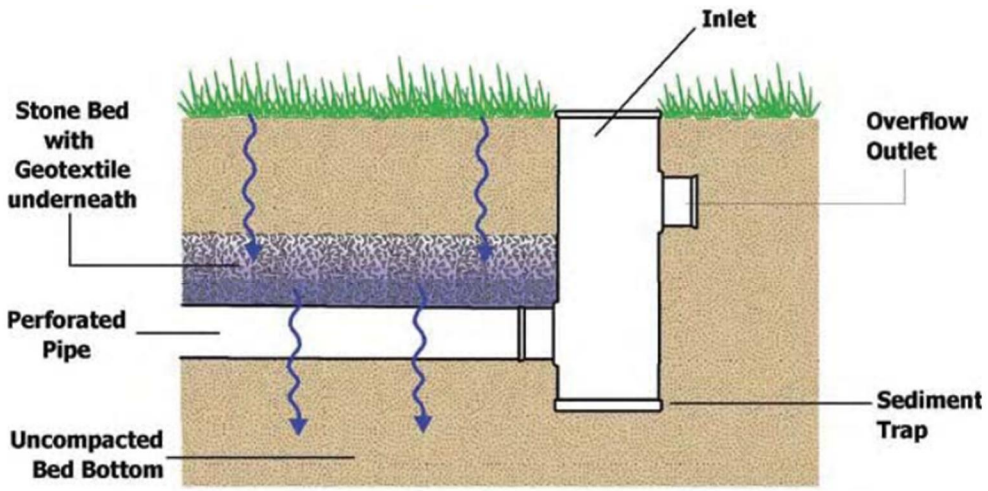


Figure 10. Subsurface Infiltration Bed Schematic
Source: LID Manual for Michigan

Infiltration Volume Standards (Subsurface Infiltration Beds)

A proposed drain tile system will be utilized to mimic the conditions of the existing drain tile system and meet the standards of a Subsurface Infiltration Bed per WCWRC Rules to provide infiltration for the First Flush Volume requirement. In areas where the existing drain tile system is in conflict with the proposed Solar Farm, a new drain tile system is proposed to both avoid the proposed trackers and increase the infiltration volume on site. Both the existing and proposed drain tile system is likely 4' to 5' underground and, according to the Preliminary Geotech Report, the high ground water levels on site are below 10' underground. This satisfies the requirement in the WCWRC Rules that the estimated high ground water elevation must be at least 3 feet from the bottom of the infiltration facility.

The outlets for the proposed Subsurface Infiltration Beds will be the existing drain tile system or in locations of existing drain tile outlets. The subsurface infiltration beds will consist of a perforated pipe of varying sizes (12" min), but, for the purpose of this exercise, it is assumed that the pipes will be 12". The pipes will generally be placed between trackers in low lying areas so that the runoff will naturally flow towards the subsurface infiltration beds.

The infiltration volume calculations for the Subsurface Infiltration Bed below are an example of what the calculations will look like for the proposed drain tile system. The calculations are only presented to show the approach, final design will require appropriate calculations that match the designed and installed subsurface network. The Infiltration Volume received from the BMPs will be equal to or greater than the First Flush Volume for each drainage area. The infiltration volume equation came from Section V, Part J in the WCWRC Rules. For this exercise, the following assumptions were made during the infiltration volume calculations. The bed bottom area is the surface area of drainage material above the perforated pipes. The width of the bed bottom area will be the width of the trench which is assumed to be 4' wide. The length of the infiltration area is equal to the length of the pipe. The infiltration design rate is an estimate based on the hydraulic conductivity data from the NRCS Web Soil Survey. The infiltration period is assumed to be 48 hours for now because the WCWRC Rules states that the period is not to exceed 48 hours.

Subsurface Infiltration Bed Storage Calculations:

Drainage Area 1:
Infiltration Volume (ft^3) = Bed bottom area (ft^2) x [Infiltration design rate (in/hr) x Infiltration Period (hr)] x (1/12)
Infiltration Volume = (4' * 4,098') * (0.4 in/hr * 48 hr) * 1/12
Infiltration Volume = 26,227 ft^3
26,227 ft^3 is greater than First Flush Volume for Drainage Area 1 that was calculated earlier, 21,726 ft^3, so the infiltration requirement is satisfied.

Drainage Area 2:
Infiltration Volume (ft^3) = Bed bottom area (ft^2) x [Infiltration design rate (in/hr) x Infiltration Period (hr)] x (1/12)
Infiltration Volume = (4' * 720') * (0.4 in/hr * 48 hr) * 1/12
Infiltration Volume = 4,608 ft^3

4,608 ft^3 is greater than First Flush Volume for Drainage Area 2 that was calculated earlier, 3,340 ft^3, so the infiltration requirement is satisfied.

Drainage Area 3:
Infiltration Volume (ft^3) = Bed bottom area (ft^2) x [Infiltration design rate (in/hr) x Infiltration Period (hr)] x (1/12)
Infiltration Volume = (4' * 7,931') * (0.4 in/hr * 48 hr) * 1/12
Infiltration Volume = 50,758 ft^3
50,758 ft^3 is greater than First Flush Volume for Drainage Area 3 that was calculated earlier, 45,793 ft^3, so the infiltration requirement is satisfied.

A depiction of where the subsurface infiltration beds will be placed on the solar site can be seen in the Preliminary Stormwater Analysis Exhibit in **Attachment B**.

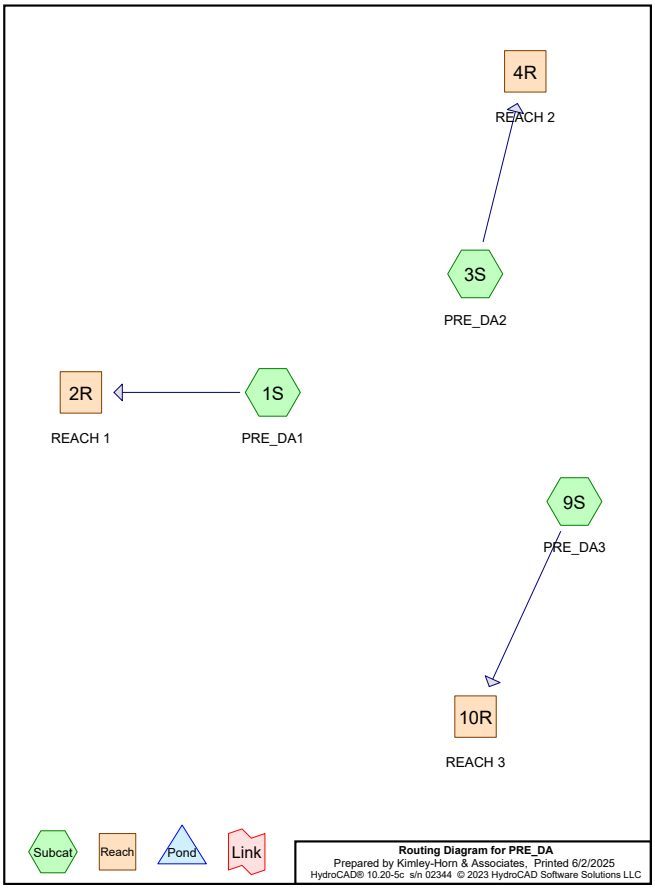
Executive Summary

The Washtenaw Solar facility will use Best Management Practices (BMPs) listed in the Washtenaw County Water Resources Commissioner (WCWRC) Rules and Guidelines to meet the stormwater requirements set forth by the County. Subsurface Infiltration Beds will be used to satisfy the Infiltration Volume requirement. Prior to final design of the BMPs, soil infiltration testing must be done on site using the soil infiltration testing guidelines in the WCWRC Rules.

Please do not hesitate to contact me if you have any questions. We appreciate your continued partnership on this project.

Calvin Carlson
Kimley-Horn of Michigan, Inc.
Calvin.Carlson@Kimley-Horn.com
331.310.0039

Attachment A – HydroCAD Report



Time span=5.00-20.00 hrs, dt=0.05 hrs, 301 points
Runoff by SCS TR-20 method, UH=SCS, Weighted-CN
Reach routing by Stor-Ind+Trans method - Pond routing by Stor-Ind method

Subcatchment1S: PRE_DA1 Runoff Area=11.970 ac 0.00% Impervious Runoff Depth>0.62"
Flow Length=895' Tc=25.3 min CN=78 Runoff=7.32 cfs 0.614 af

Subcatchment3S: PRE_DA2 Runoff Area=1.840 ac 0.00% Impervious Runoff Depth>0.62"
Flow Length=263' Tc=10.1 min CN=78 Runoff=1.85 cfs 0.095 af

Subcatchment9S: PRE_DA3 Runoff Area=25.230 ac 0.00% Impervious Runoff Depth>0.60"
Flow Length=2,193' Tc=61.3 min CN=78 Runoff=8.19 cfs 1.270 af

Reach 2R: REACH 1 Inflow=7.32 cfs 0.614 af
Outflow=7.32 cfs 0.614 af

Reach 4R: REACH 2 Inflow=1.85 cfs 0.095 af
Outflow=1.85 cfs 0.095 af

Reach 10R: REACH 3 Inflow=8.19 cfs 1.270 af
Outflow=8.19 cfs 1.270 af

Total Runoff Area = 39.040 ac Runoff Volume = 1.980 af Average Runoff Depth = 0.61"
100.00% Pervious = 39.040 ac 0.00% Impervious = 0.000 ac

Summary for Subcatchment 1S: PRE_DA1

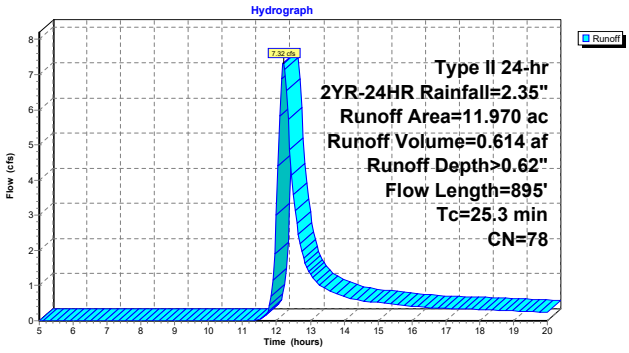
Runoff = 7.32 cfs @ 12.21 hrs, Volume= 0.614 af, Depth> 0.62"
Routed to Reach 2R : REACH 1

Runoff by SCS TR-20 method, UH=SCS, Weighted-CN, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs
Type II 24-hr 2YR-24HR Rainfall=2.35"

	Area (ac)	CN	Description
*	11.970	78	
	11.970		100.00% Pervious Area

Tc (min)	Length (feet)	Slope (ft/ft)	Velocity (ft/sec)	Capacity (cfs)	Description
10.2	100	0.0271	0.16		**Sheet Flow,** Grass: Short n= 0.150 P2= 2.31"
15.1	795	0.0157	0.88		**Shallow Concentrated Flow,** Short Grass Pasture Kv= 7.0 fps
25.3	895	Total			

Subcatchment 1S: PRE_DA1



Summary for Subcatchment 3S: PRE_DA2

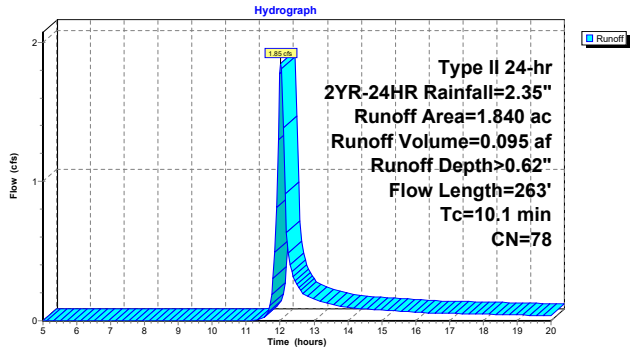
Runoff = 1.85 cfs @ 12.03 hrs, Volume= 0.095 af, Depth> 0.62"
Routed to Reach 4R : REACH 2

Runoff by SCS TR-20 method, UH=SCS, Weighted-CN, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs
Type II 24-hr 2YR-24HR Rainfall=2.35"

	Area (ac)	CN	Description
*	1.840	78	
	1.840		100.00% Pervious Area

Tc (min)	Length (feet)	Slope (ft/ft)	Velocity (ft/sec)	Capacity (cfs)	Description
8.1	100	0.0488	0.21		**Sheet Flow,** Grass: Short n= 0.150 P2= 2.31"
2.0	163	0.0390	1.38		**Shallow Concentrated Flow,** Short Grass Pasture Kv= 7.0 fps
10.1	263	Total			

Subcatchment 3S: PRE_DA2



Summary for Subcatchment 9S: PRE_DA3

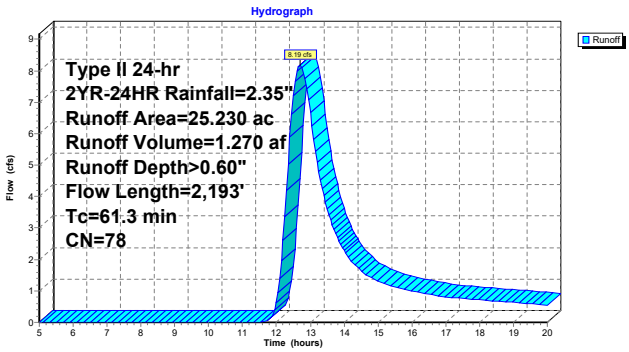
Runoff = 8.19 cfs @ 12.71 hrs, Volume= 1.270 af, Depth> 0.60"
Routed to Reach 10R : REACH 3

Runoff by SCS TR-20 method, UH=SCS, Weighted-CN, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs
Type II 24-hr 2YR-24HR Rainfall=2.35"

	Area (ac)	CN	Description
*	25.230	78	
	25.230		100.00% Pervious Area

Tc (min)	Length (feet)	Slope (ft/ft)	Velocity (ft/sec)	Capacity (cfs)	Description
8.8	100	0.0393	0.19		**Sheet Flow,** Grass: Short n= 0.150 P2= 2.31"
52.5	2,093	0.0090	0.66		**Shallow Concentrated Flow,** Short Grass Pasture Kv= 7.0 fps
61.3	2,193	Total			

Subcatchment 9S: PRE_DA3



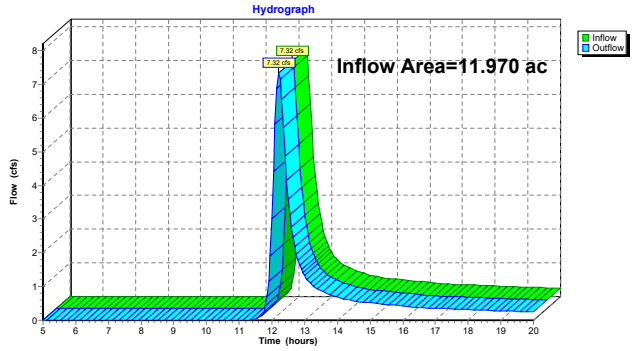
Summary for Reach 2R: REACH 1

[40] Hint: Not Described (Outflow=Inflow)

Inflow Area = 11.970 ac, 0.00% Impervious, Inflow Depth > 0.62" for 2YR-24HR event
Inflow = 7.32 cfs @ 12.21 hrs, Volume= 0.614 af
Outflow = 7.32 cfs @ 12.21 hrs, Volume= 0.614 af, Atten= 0%, Lag= 0.0 min

Routing by Stor-Ind+Trans method, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs

Reach 2R: REACH 1



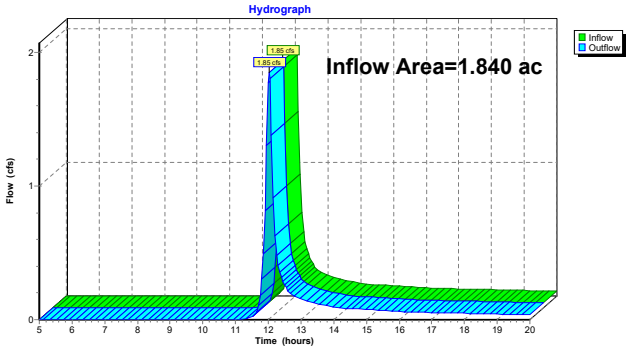
Summary for Reach 4R: REACH 2

[40] Hint: Not Described (Outflow=Inflow)

Inflow Area = 1.840 ac, 0.00% Impervious, Inflow Depth > 0.62" for 2YR-24HR event
Inflow = 1.85 cfs @ 12.03 hrs, Volume= 0.095 af
Outflow = 1.85 cfs @ 12.03 hrs, Volume= 0.095 af, Atten= 0%, Lag= 0.0 min

Routing by Stor-Ind+Trans method, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs

Reach 4R: REACH 2



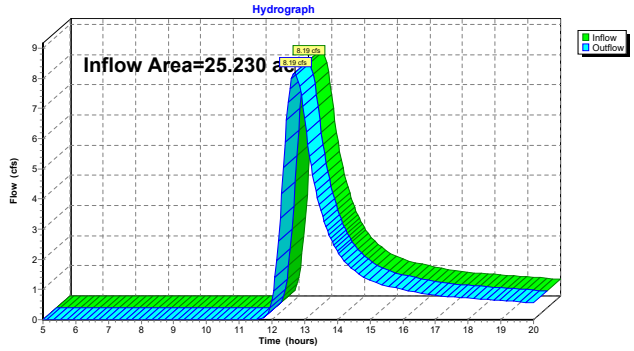
Summary for Reach 10R: REACH 3

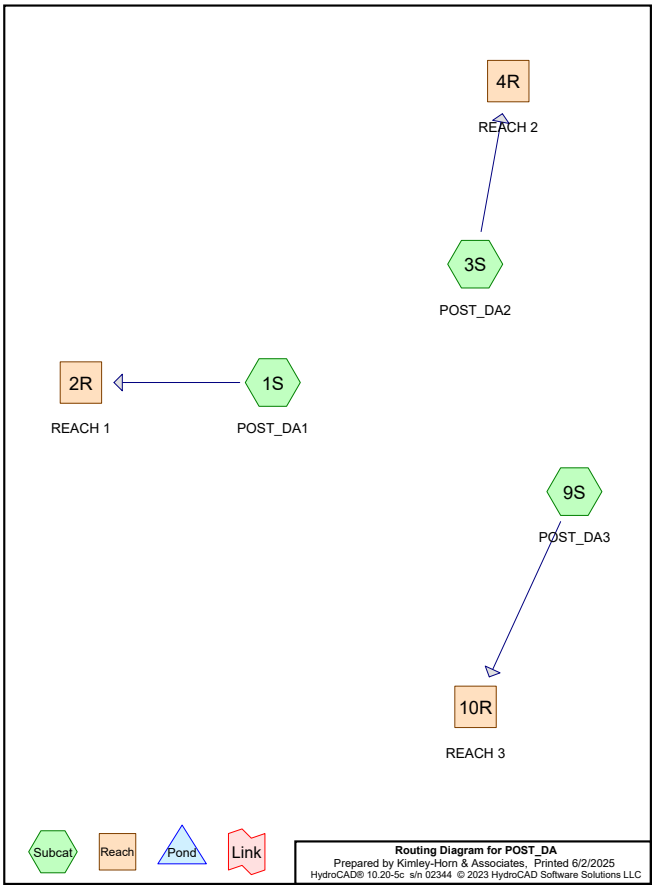
[40] Hint: Not Described (Outflow=Inflow)

Inflow Area = 25.230 ac, 0.00% Impervious, Inflow Depth > 0.60" for 2YR-24HR event
Inflow = 8.19 cfs @ 12.71 hrs, Volume= 1.270 af
Outflow = 8.19 cfs @ 12.71 hrs, Volume= 1.270 af, Atten= 0%, Lag= 0.0 min

Routing by Stor-Ind+Trans method, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs

Reach 10R: REACH 3





Time span=5.00-20.00 hrs, dt=0.05 hrs, 301 points
Runoff by SCS TR-20 method, UH=SCS, Weighted-CN
Reach routing by Stor-Ind+Trans method - Pond routing by Stor-Ind method

Subcatchment1S: POST_DA1 Runoff Area=11.970 ac 4.21% Impervious Runoff Depth>0.66"
Flow Length=895' Tc=24.4 min CN=79 Runoff=8.13 cfs 0.658 af

Subcatchment3S: POST_DA2 Runoff Area=1.840 ac 0.00% Impervious Runoff Depth>0.62"
Flow Length=263' Tc=10.1 min CN=78 Runoff=1.85 cfs 0.095 af

Subcatchment9S: POST_DA3 Runoff Area=25.230 ac 4.52% Impervious Runoff Depth>0.65"
Flow Length=2,193' Tc=64.2 min CN=79 Runoff=8.61 cfs 1.358 af

Reach 2R: REACH 1 Inflow=8.13 cfs 0.658 af
Outflow=8.13 cfs 0.658 af

Reach 4R: REACH 2 Inflow=1.85 cfs 0.095 af
Outflow=1.85 cfs 0.095 af

Reach 10R: REACH 3 Inflow=8.61 cfs 1.358 af
Outflow=8.61 cfs 1.358 af

Total Runoff Area = 39.040 ac Runoff Volume = 2.111 af Average Runoff Depth = 0.65"
95.79% Pervious = 37.396 ac 4.21% Impervious = 1.644 ac

Summary for Subcatchment 1S: POST_DA1

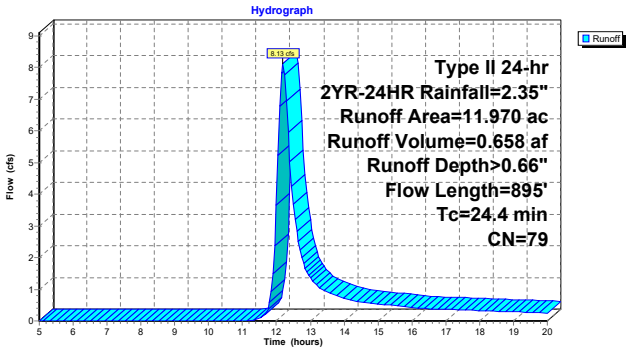
Runoff = 8.13 cfs @ 12.20 hrs, Volume= 0.658 af, Depth> 0.66"
Routed to Reach 2R : REACH 1

Runoff by SCS TR-20 method, UH=SCS, Weighted-CN, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs
Type II 24-hr 2YR-24HR Rainfall=2.35"

	Area (ac)	CN	Description
*	11.466	78	
*	0.504	98	
	11.970	79	Weighted Average
	11.466		95.79% Pervious Area
	0.504		4.21% Impervious Area

Tc (min)	Length (feet)	Slope (ft/ft)	Velocity (ft/sec)	Capacity (cfs)	Description
10.2	100	0.0271	0.16		**Sheet Flow,** Grass: Short n= 0.150 P2= 2.31"
2.3	173	0.0315	1.24		**Shallow Concentrated Flow,** Short Grass Pasture Kv= 7.0 fps
1.1	148	0.0122	2.24		**Shallow Concentrated Flow,** Paved Kv= 20.3 fps
10.8	474	0.0110	0.73		**Shallow Concentrated Flow,** Short Grass Pasture Kv= 7.0 fps
24.4	895	Total			

Subcatchment 1S: POST_DA1



Summary for Subcatchment 3S: POST_DA2

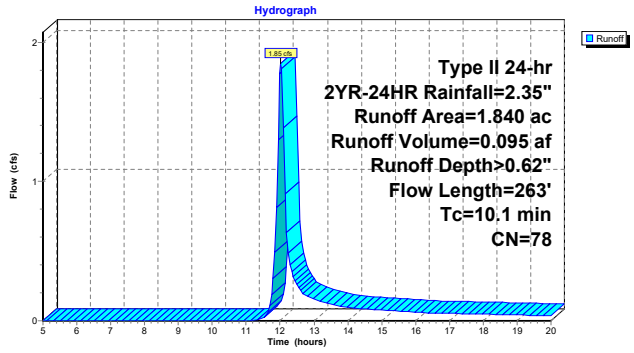
Runoff = 1.85 cfs @ 12.03 hrs, Volume= 0.095 af, Depth> 0.62"
Routed to Reach 4R : REACH 2

Runoff by SCS TR-20 method, UH=SCS, Weighted-CN, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs
Type II 24-hr 2YR-24HR Rainfall=2.35"

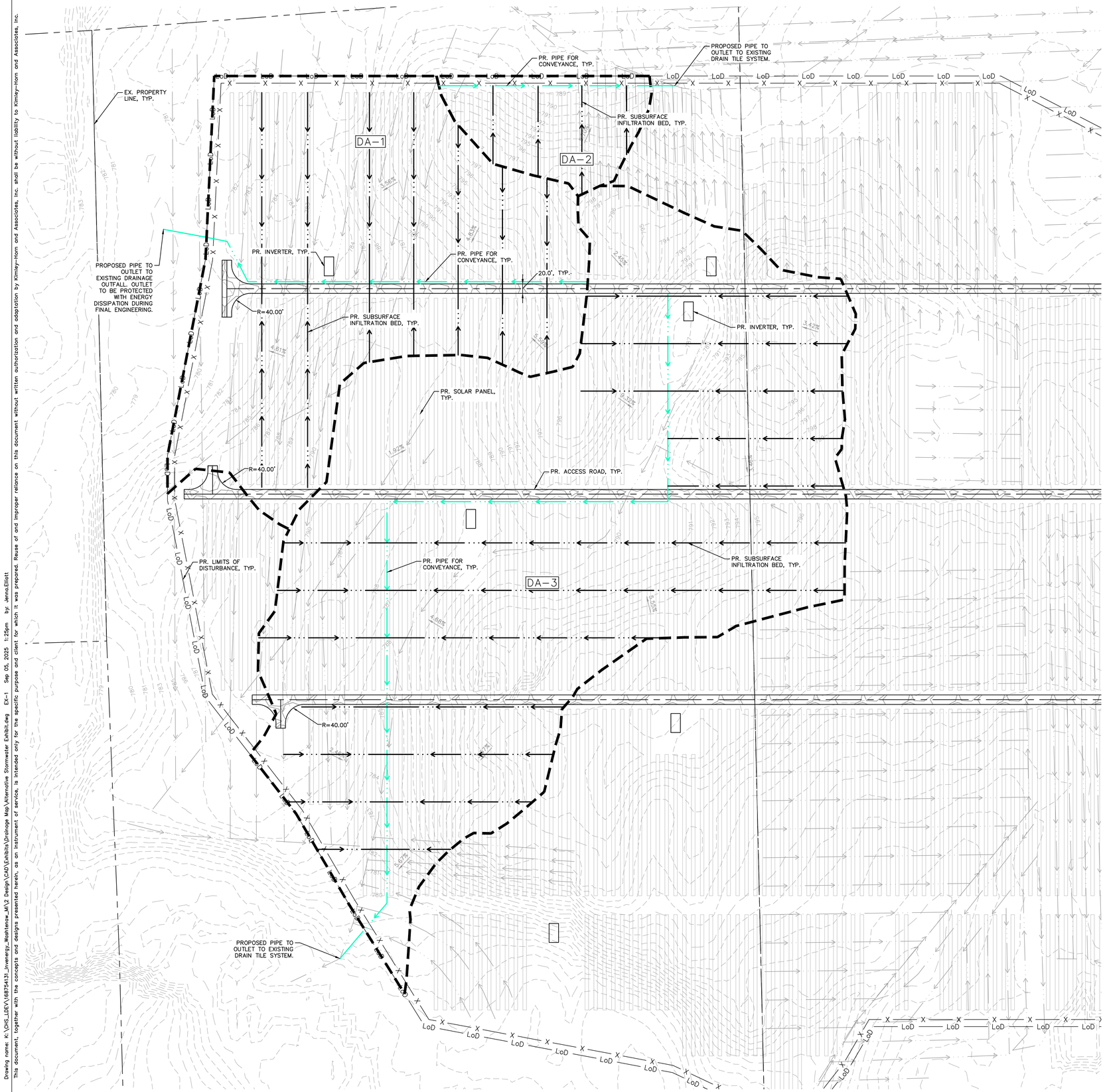
	Area (ac)	CN	Description
*	1.840	78	
	1.840		100.00% Pervious Area

Tc (min)	Length (feet)	Slope (ft/ft)	Velocity (ft/sec)	Capacity (cfs)	Description
8.1	100	0.0488	0.21		**Sheet Flow,** Grass: Short n= 0.150 P2= 2.31"
2.0	163	0.0390	1.38		**Shallow Concentrated Flow,** Short Grass Pasture Kv= 7.0 fps
10.1	263	Total			

Subcatchment 3S: POST_DA2



Attachment B – Preliminary Stormwater Analysis Exhibit



NORTH

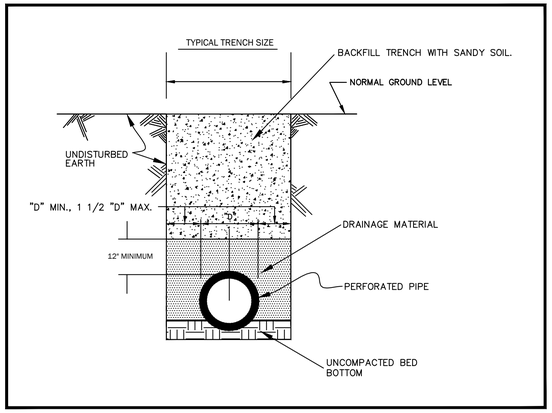
GRAPHIC SCALE IN FEET
0 50 100 200

LEGEND

PROPERTY LINE	
PROPERTY LINE SETBACK	
EX. CONTOURS	XXX
EX. FLOW DIRECTION AND SLOPE	XX%
EX. DRAIN TILE	
DRAINAGE AREA	
PR. GRAVEL ACCESS ROAD	
PR. PANELS	
PR. PANEL LIMITS	
PR. INVERTER	
PR. FENCE	X X X X
PR. LIMITS OF DISTURBANCE	LoD LoD LoD
PR. SUBSURFACE INFILTRATION BED	
PR. PIPE FOR CONVEYANCE	

NOTES

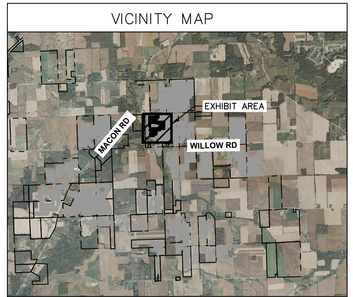
1. SEE DETAIL 1, THIS SHEET FOR SUBSURFACE INFILTRATION BED.
2. THIS EXHIBIT IS FOR COORDINATION WITH WASHTENAW COUNTY ONLY AND NOT TO BE USED FOR CONSTRUCTION OR PERMITTING.



1
EX-1
SUBSURFACE INFILTRATION BED

SCALE: NTS

VICINITY MAP



NOT TO SCALE

No.	REVISIONS	DATE

Invenergy

Kimley»Horn
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570 LAKE COOK ROAD, SUITE 200
DEERFIELD, IL 60015 (847) 260-7804
WWW.KIMLEY-HORN.COM

PRELIMINARY NOT FOR CONSTRUCTION

KHA PROJECT 168754131
DATE 09/05/2025
AS SHOWN
DESIGNED BY JLE
DRAWN BY JLE
CHECKED BY CPC

PRELIMINARY STORMWATER ANALYSIS EXHIBIT

WASHTENAW SOLAR

WASHTENAW COUNTY, MI

SHEET NUMBER
EX-1

Drawing name: K:\CHS_LDEV\168754131_Invenergy_Washtenaw_MI\2 Design\CAD\Exhibits\Drainage Map\Alternative Stormwater Exhibit.dwg EX-1 Sep 05, 2025 1:25pm by: Anna.Elliott
This document, together with the concepts and designs presented herein, as an instrument of service, is intended only for the specific purpose and client for which it was prepared. Reuse of and improper reliance on this document without written authorization and adaptation by Kimley-Horn and Associates, Inc. shall be without liability to Kimley-Horn and Associates, Inc.

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Appendix B: Correspondence with the Washtenaw County Water Resources Commissioner's Office

Outlook

Fw: Washtenaw County Stormwater Approach (Privileged and Confidential)

From Keenan, Sean <SKeenan@invenergy.com>
Date Wed 8/27/2025 11:45 AM
To Bernstein, Hannah <HBernstein@invenergy.com>
Cc Durgan, Tyler <TDurgan@invenergy.com>

Sean Keenan | Manager, Renewable Development
Invenergy
One South Wacker Drive, Suite 1500, Chicago, IL 60606
skeenan@invenergy.com | W 708-688-1221 | C 312-989-7499

From: Matthew Byrne <byrnem@washtenaw.org>
Sent: Monday, July 7, 2025 11:54 AM
To: Elliott, Jenna <Jenna.Elliott@kimley-horn.com>; Carlson, Calvin <Calvin.Carlson@kimley-horn.com>; Polen, Kirsten <KPolen@invenergy.com>
Cc: JKampa <JKampa@invenergy.com>
Subject: RE: Washtenaw County Stormwater Approach

Hi All – Please see my markup of the memo attached. Let me know if you have any questions.

Thanks,

Matt Byrne, P.E., CFM
Stormwater Engineer
Water Resources Commissioner's Office
705 N. Zeeb Rd., Ann Arbor, MI
Cell: (715) 271-9693
Office:(734) 222-6860

From: Elliott, Jenna <Jenna.Elliott@kimley-horn.com>
Sent: Tuesday, July 1, 2025 6:03 PM
To: Matthew Byrne <byrnem@washtenaw.org>; Carlson, Calvin <Calvin.Carlson@kimley-horn.com>; Polen, Kirsten <KPolen@invenergy.com>
Cc: JKampa <JKampa@invenergy.com>
Subject: RE: Washtenaw County Stormwater Approach

CAUTION: This email originated from outside of the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe.

Hi Matt,

The time that works best for everyone is 12pm on Monday, July 7th.

Thanks,

Jenna Elliott
Kimley-Horn | 570 Lake Cook Rd, Suite 200, Deerfield, IL 60015
Direct: 224-214-4615
Connect with us: Twitter | LinkedIn | Facebook | Instagram | Kimley-Horn.com

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From: Matthew Byrne <byrnem@washtenaw.org>
Sent: Monday, June 30, 2025 8:09 AM
To: Carlson, Calvin <Calvin.Carlson@kimley-horn.com>; Polen, Kirsten <KPolen@invenergy.com>; Elliott, Jenna <Jenna.Elliott@kimley-horn.com>
Cc: JKampa <JKampa@invenergy.com>
Subject: RE: Washtenaw County Stormwater Approach

Some people who received this message don't often get email from byrnem@washtenaw.org. Learn why this is important

Hi Calvin – I'll be handling this project moving forward. My availability for a pre-app meeting is below. We'll do it virtually via zoom. I'll send out the invite. Let me know what date works best for you and the property owner.

Wed July 2: 11-3 pm
Mon July 7: 9-3 pm
Tues July 8: 9-11 am
Wed July 9: 11-4 pm
Thurs July 10: 1-4 pm
Fri July 11: 12-4 pm

Thanks,

Matt Byrne, P.E., CFM
Stormwater Engineer
Water Resources Commissioner's Office
705 N. Zeeb Rd., Ann Arbor, MI
Cell: (715) 271-9693
Office:(734) 222-6860

From: Carlson, Calvin <Calvin.Carlson@kimley-horn.com>
Sent: Monday, June 23, 2025 10:47 AM
To: Matthew Byrne <byrnem@washtenaw.org>; Polen, Kirsten <KPolen@invenergy.com>; Elliott, Jenna <Jenna.Elliott@kimley-horn.com>
Cc: JKampa <JKampa@invenergy.com>
Subject: Re: Washtenaw County Stormwater Approach

CAUTION: This email originated from outside of the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe.

Thanks Matt!

We can fill this out. How does it work after that? Do you send us times to schedule something?

Thanks,

Cal
Calvin P. Carlson, P.E.
Kimley-Horn | 570 Lake Cook Road, Suite 200. Deerfield, IL 60015
Direct: 331 310 0039

Book time to meet with me

From: Matthew Byrne <byrnem@washtenaw.org>
Sent: Friday, June 20, 2025 1:02 PM
To: Polen, Kirsten <KPolen@invenergy.com>; Elliott, Jenna <Jenna.Elliott@kimley-horn.com>
Cc: Carlson, Calvin <Calvin.Carlson@kimley-horn.com>; JKampa <JKampa@invenergy.com>
Subject: RE: Washtenaw County Stormwater Approach

Some people who received this message don't often get email from byrnem@washtenaw.org. Learn why this is important

Hi All – Thanks for sending this over. I will verify internally with our office, but chances are good that we'll claim complete jurisdiction over the project due to multiple discharges to the county drain network.

In the meantime, can you please fill in this form to request a pre-app meeting?

https://www.washtenaw.org/3911/Stormwater-Review-Projects

Thanks,

Matt Byrne, P.E., CFM
Stormwater Engineer
Water Resources Commissioner's Office
705 N. Zeeb Rd., Ann Arbor, MI
Cell: (715) 271-9693
Office:(734) 222-6860

From: Polen, Kirsten <KPolen@invenergy.com>
Sent: Friday, June 20, 2025 10:24 AM
To: Matthew Byrne <byrnem@washtenaw.org>; Elliott, Jenna <Jenna.Elliott@kimley-horn.com>
Cc: Carlson, Calvin <Calvin.Carlson@kimley-horn.com>; Kampa, James <JKampa@invenergy.com>
Subject: Re: Washtenaw County Stormwater Approach

CAUTION: This email originated from outside of the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe.

Hi Matt,

Please see the attached KMZs of the parcels included within the project area, and portions of county drains identified near the project area. We currently plan to avoid the county drains with any system facilities, but may not be able to avoid discharging stormwater into the county drains.

We would still like to meet to discuss our proposed approach in the case that we do end up being under the jurisdiction of the county.

Thank you,

Kirsten Polen | Senior Staff Engineer, Renewable Engineering | She / Her
Invenergy | One South Wacker Drive, Suite 1500, Chicago, IL 60606
KPolen@invenergy.com | W (630)-658-9124

From: Matthew Byrne <byrnem@washtenaw.org>
Sent: Thursday, June 12, 2025 12:32 PM
To: Elliott, Jenna <Jenna.Elliott@kimley-horn.com>
Cc: Carlson, Calvin <Calvin.Carlson@kimley-horn.com>; Polen, Kirsten <kpolen@invenergy.com>; Kampa, James <JKampa@invenergy.com>
Subject: [EXTERNAL] RE: Washtenaw County Stormwater Approach

Hi Jenna – Can you provide a map of the project area. Unless there's work proposed in a county drain easement or if you plan to discharge to the a county drain, our office doesn't have jurisdiction in Saline Township.

Thanks,

Matt Byrne, P.E., CFM
Stormwater Engineer
Water Resources Commissioner's Office
705 N. Zeeb Rd., Ann Arbor, MI
Cell: (715) 271-9693
Office:(734) 222-6860

From: Elliott, Jenna <Jenna.Elliott@kimley-horn.com>
Sent: Wednesday, June 11, 2025 1:49 PM
To: Matthew Byrne <byrnem@washtenaw.org>
Cc: Carlson, Calvin <Calvin.Carlson@kimley-horn.com>; Polen, Kirsten <kpolen@invenergy.com>; JKampa <JKampa@invenergy.com>
Subject: Washtenaw County Stormwater Approach

CAUTION: This email originated from outside of the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe.

Hi Matt,

I believe you have met with my colleague, Calvin Carlson, to discuss stormwater requirements for a proposed solar farm project in Washtenaw County. The proposed solar farm is called Washtenaw Solar. We have been putting together a stormwater management approach for Washtenaw Solar using the Washtenaw County Water Resources Commissioner Rules and Guidelines, see attached memo for the approach we have put together so far. We would love to meet with you next week in order to go over the stormwater management approach and get your thoughts. Could you please let me know what your availability looks like next week?

Thanks,

Jenna Elliott
Kimley-Horn | 570 Lake Cook Rd, Suite 200, Deerfield, IL 60015
Direct: 224-214-4615
Connect with us: Twitter | LinkedIn | Facebook | Instagram | Kimley-Horn.com

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Appendix C: Washtenaw County Water Resources Commissioner's Office Comments on the Preliminary Stormwater Analysis Memo

Kimley»Horn
of Michigan, Inc.

MEMORANDUM

To: Kirsten Polen - Invenergy

From: Calvin Carlson - Kimley-Horn & Associates, Inc.

Date: June 10, 2025

Subject: Washtenaw Solar – Preliminary Stormwater Analysis Memo

---

This memorandum provides a general overview of the existing and proposed conditions for the Washtenaw Solar Facility in Saline Township, Washtenaw County, Michigan. This preliminary analysis is intended to propose stormwater solutions that comply with the Washtenaw County Water Resources Commissioner (WCWRC) Rules and Guidelines. For the purpose of this Memo, the stormwater design will focus on three representative drainage areas on site.

Existing Conditions

The project area consists of approximately 2,170 acres of farmland. The project area is located north of Hack Road and west of Maple Road, near Saline, MI. Rural residential areas are located north, south, east, and west of the site area. The existing topography for the site ranges from gently to severely sloped (0%-40%). The site generally flows from the northwest to the southeast. West of Macon Road, the site flows east; east of Macon Road the flow goes toward the southeast corner of the site, going into the North Branch Macon Creek which flows into the Macon Drain. Per available NRCS soil mapping, the on-site soils generally consist of loams, with approximately 76% being non-hydric soils and approximately 24% of the site was mapped hydric soils. The soils present on the site range from hydrologic soil group A to D, with much of the site considered Hydrologic Group B / D and C / D. An existing drain tile was identified and located for the project. The locations of the existing drain tile lines are shown in “Washtenaw Solar - Drain Mapping - 12.13.2024.kml” provided by Invenergy on January 3, 2025.

Post-Development Runoff

The proposed development will include PV solar module and tracker systems, gravel aggregate access drives, associated electrical inverter pads, underground electric cabling, and vegetative buffers. The project will be surrounded by a perimeter fence. The proposed area of disturbance is approximately 1,330 acres. Solar panels will be mounted on piles and elevated above the ground as to preserve existing underlying soil and allow for revegetation. Gravel access roads are spaced out among several rows of solar arrays to maximize the amount of ground that will be ultimately revegetated. Per Hydrology Response on Solar Farms, published by the American Society of Civil Engineers (ASCE), with well-maintained vegetation underneath the panels, the solar panels themselves do not have much effect on total volumes of the runoff or peak discharge rates as the net increase in impervious ground surface is negligible. Rainfall that falls directly on a solar panel runs to the pervious areas around the surrounding panels. In the post-developed condition, the existing cultivated farmland will be converted to native meadow vegetation to stabilize and provide year-round ground cover. This post-condition emulates the meadow which has a CN of 78 per NRCS TR-55. For the purposes of this memo and to be conservative

with our assumptions, the access roads are reflected in stormwater calculations as impervious with CN of 98 per NRCS TR-55. The concrete pads for the inverters will also be factored in as impervious area with a CN of 98. The proposed solar development will include a proposed drain tile system (or proposed infiltration bed system) to mimic the existing system and meet the WCWRC Stormwater Management Requirements described below.

WCWRC Stormwater Management Requirements

Per the WCWRC Rules and Guidelines (the WCWRC Rules), the post-construction stormwater management methods must treat the First Flush Volume, the Bankfull Volume Difference and the 100-Year Storm. On a call with Matt Byrne, the Washtenaw County stormwater engineer, on 1/03/25, solar farms are typically exempt from meeting the 100-Year Storm requirements. The First Flush Volume is defined as the first inch of rain from the entire contributing watershed as determined by the Rational Method while the Pre- and Post- Bankfull Volumes are calculated using 2-year, 24-hour storm event recurrence as determined by the NRCS Method. Per the WCWRC Rules, the Infiltration Volume is equal to the greater of the First Flush Volume or the Bankfull Volume Difference. For our site, the First Flush Volume will always be greater due to the large size of the drainage areas and the low percentage of impervious ground cover in each drainage area. The Bankfull Volume Difference, or the difference between the Pre-Bankfull Volume and the Post-Bankfull Volume, as calculated by the WCWRC Rules, must be detained.

Runoff Calculations

The First Flush Volumes and Bankfull Volume Differences were analyzed for three representative drainage areas on the Washtenaw Solar Site. The First Flush Volumes were found using the calculations given in the WCWRC Rules and Guidelines. The First Flush Runoff Calculations can be seen below. The weighted runoff coefficient used in the First Flush Runoff Calculations, 0.5, is a conservative assumption that was made using the WCWRC Rules and Guidelines. The Bankfull Volume Difference calculations were found using the NRCS Method in HydroCAD. The HydroCAD report is shown in **Attachment A**. Although the existing land cover is Row Crop, the WCWRC requires that the pre-development landcover is modeled as either Good Cover Woods or Meadow, so we chose to go with Meadow. The post-development landcover will predominantly be Meadow, but there will be impervious areas for the road and equipment pads. Therefore, the difference between the pre- and post-development bankfull volumes will be the runoff that comes from the proposed impervious areas. The table below lists the runoff volumes found for the three representative drainage areas.

First Flush Runoff Calculations:

$V_{ff} = (1")(\frac{1'}{12"})(\frac{43560ft^2}{1ac})AC$

A = Total Site Areas (ac) excluding BMPs

C = Weighted Runoff Coefficient

You're required to manage for the infiltration volume, which is this case, is the first flush volume. If you cannot infiltrate this volume, then you should detain it plus an additional 20%. The bankful difference should be included in your calculations still.

Runoff Volumes				
Drainage Area (AC)	**First Flush Volume (ft^3)**	**Pre-Development Bankfull Volume (ft^3)**	**Post-Development Bankfull Volume (ft^3)**	**Bankfull Volume Difference (ft^3)**
11.97	21,726	26,746	28,662	1,916
1.84	3,340	4,138	4,138	0
25.23	45,793	55,321	59,154	3,833

Best Management Practices (BMP) Guidelines

The WCWRC Rules and Guidelines states that BMPs can be used to reduce both the amount of detention/retention required and to meet the First Flush Volume infiltration requirements. The applicable BMPs listed in the WCWRC for a solar farm are as follows: Infiltration Basin, Subsurface Infiltration Bed, Infiltration Trench, Bioretention Systems, Rain Gardens, Bioswale, and Vegetated Filter Strip. The calculations to find the Storage Volume provided by each individual BMP can be found in Section IV, Part C in the WCWRC Rules and Guidelines. The infiltration volume for the listed BMPs can be found with the equation, Infiltration Volume = Infiltration Rate x 6 hours x BMP Area. See Section V, Part D in the WCWRC Rules and Guidelines for more design requirements regarding Infiltration BMPs. The Total Volume Reduction Credit is the sum of the Storage Volume and the Infiltration Volume provided by the BMPs.

For purposes of these calculations, we will work to show that the First Flush Volume, or Infiltration Volume, will infiltrate into the soil with the proposed infiltration BMPs and the Bankfull Volume Difference will be stored with the proposed volume reduction BMPs, not including the volume reduction associated with the infiltration BMPs.

Prior to final design, soil infiltration testing must be completed in BMP areas to understand the infiltration rates in these areas per the WCWRC Rules. For this exercise, NRCS Web Soil Survey data showing the hydraulic conductivity of the soil gave us a preliminary estimate of the soil infiltration rates. The saturated hydraulic conductivity in this area is roughly 0.4 in/hr, so we are assuming an infiltration rate of 0.4 in/hr.

Best Management Practices (BMP) Solutions

The purpose of this exercise is to identify post construction stormwater BMPs, described in the WCWRC Rules, that satisfy the Infiltration Volume and Storage Volume requirements and have the least impact to the existing site and existing drainage patterns. To do this, the project is choosing BMPs that are similar to the existing drain tile system that is out there today that will need to be rerouted and the meadow ground cover that is proposed underneath the panels. The two BMPs that fit that description in the WCWRC Rules are Subsurface Infiltration Beds for the Storage Volume and Vegetative Filter Strips for the Infiltration Volume.

Subsurface Infiltration Beds

A subsurface infiltration bed can be used retain and infiltrate stormwater runoff. See the diagram below for an example of what the infiltration bed can look like. Exact dimensions, materials, and details will be provided during the design process. The volume reduction calculations can also be seen below. Section V, Part J in the WCWRC Rules and Guidelines contains more information on the design requirements for subsurface infiltration beds.

Volume Reduction Calculations:

BMP Storage Volume = Infiltration Area x Depth of underdrain material x Void ratio of storage material

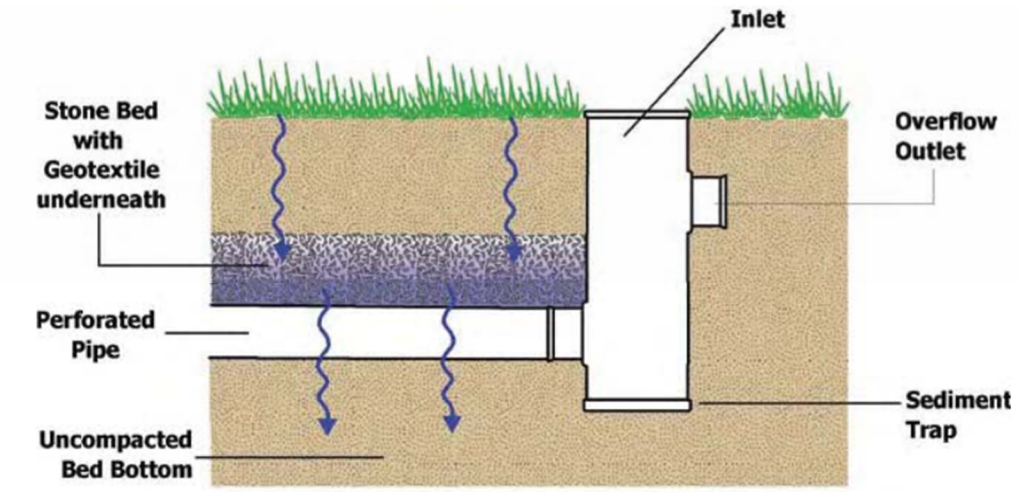


Figure 10. Subsurface Infiltration Bed Schematic
Source: LID Manual for Michigan

Vegetated Filter Strip

A vegetated filter strip can be used for infiltration purposes as it does not have a significant volume reducing capacity. Vegetated filter strips are a linear strip of dense vegetation used to treat sheet flow runoff. The vegetation should consist of native or locally adapted species. See the diagram below for an example of what a vegetative filter strip can look like. Section V, Part L in the WCWRC Rules and Guidelines contains more information on volume reduction calculations and design requirements for vegetative filter strips.

Infiltration Volume Calculations:

Infiltration Volume = Infiltration Rate x 6 hours x BMP Area

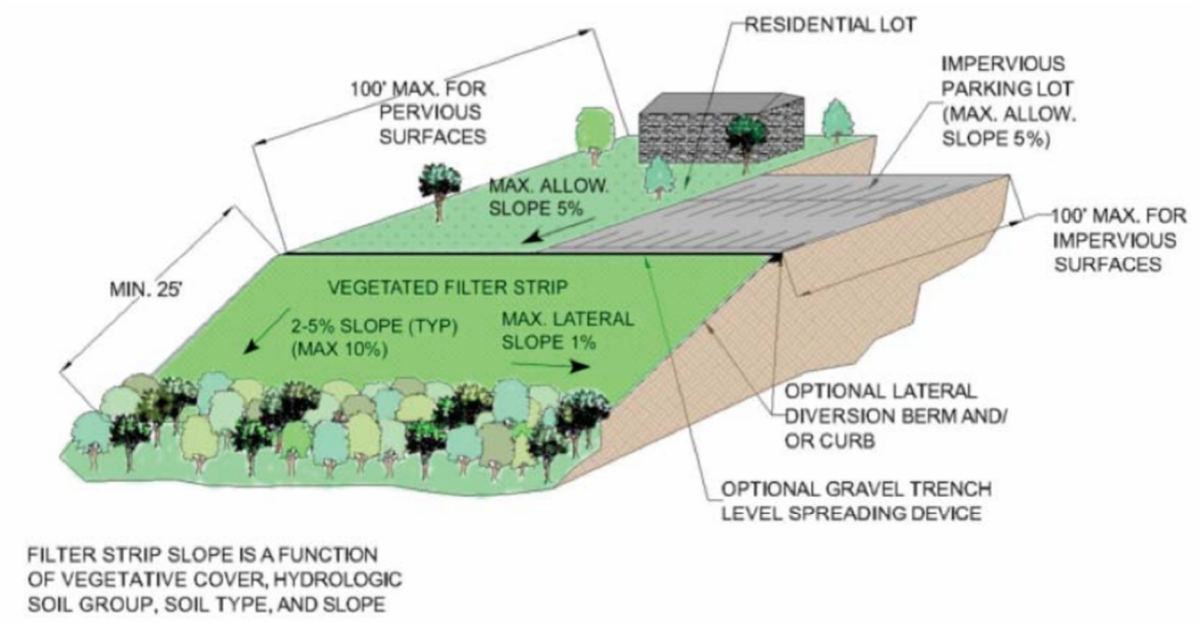


Figure 12. Vegetated Filter Strip
Source: LID Manual for Michigan

Vegetated filter strips used for water quality, not necessarily volume. The volume can be accounted for my applying the CN of the veg filter strip to the tributary area, per the rules

Infiltration Volume Standards (Vegetative Filter Strips)

The WCWRC general requirements for vegetative filter strips states that the stormwater entering the filter strip must be sheet flow which is generally defined as slopes between 2 and 5% with max slopes being 10%. We will designate areas that meet this requirement within our project area to place the filter strips. We will also place the filter strips in areas where the infiltration rate of the soil is sufficient. An

example of where the vegetative filter strips will be placed on the solar site can be seen in the Preliminary Stormwater Analysis Exhibit in **Attachment B**.

The vegetative filter strips will be sized to satisfy the onsite infiltration requirement set forth by the WCWRC. The calculations below show how the vegetative filter strips were sized for three representative drainage areas to infiltrate the First Flush Volume for each area. The calculations are just presented to show the approach, calculations are subject to change during final design. The infiltration volume calculation came from Worksheet 11 in Section IV, Part E in the WCWRC Rules and Guidelines. The soil infiltration rate is an estimated based on the hydraulic conductivity data from the NRCS Web Soil Survey. Prior to final engineering, the soil infiltration rate will need to come from on-site soil infiltration testing per the WCWRC Rules.

Vegetative Filter Sizing Calculations:

Drainage Area 1:
Infiltration Volume = Infiltration Rate x 6 hours x BMP Area
21,726 ft^3 = 0.4 in/hr * $(\frac{1ft}{12in})$ * 6 hrs * BMP Area
BMP Area = 108,630 ft^2

Drainage Area 2:
Infiltration Volume = Infiltration Rate x 6 hours x BMP Area
3,340 ft^3 = 0.4 in/hr * $(\frac{1ft}{12in})$ * 6 hrs * BMP Area
BMP Area = 16,700 ft^2

Drainage Area 3:
Infiltration Volume = Infiltration Rate x 6 hours x BMP Area
45,793 ft^3 = 0.4 in/hr * $(\frac{1ft}{12in})$ * 6 hrs * BMP Area
BMP Area = 228,965 ft^2

This isn't right. To account for the volume reduction, use the CN for the filter strip and apply to the site area (tributary area).

Storage Volume Reduction Standards (Subsurface Infiltration Beds)

A proposed drain tile system will be utilized to mimic the conditions of the existing drain tile system and meet the standards of a Subsurface Infiltration Bed per WCWRC Rules to provide Storage Volume Reduction for the Bankfull Volume Difference storage requirement. In areas where the existing drain tile system is in conflict with the proposed Solar Farm, a new drain tile system is proposed to both avoid the proposed trackers and increase the storage volume on site. Both the existing and proposed drain tile system is likely 4' to 5' underground and, according to the Preliminary Geotech Report, the high ground water levels on site are below 10' underground. This satisfies the requirement in the WCWRC Rules that the estimated high ground water elevation must be at least 3 feet from the bottom of the infiltration facility.

The outlets for the proposed Subsurface Infiltration Beds will be the existing drain tile system or in locations of existing drain tile outlets. The subsurface infiltration beds will consist of a perforated pipe of varying sizes, but, for the purpose of this exercise, it is assumed that the pipes will be 8". The pipes

12" min pipe size

will generally be placed between trackers in low lying areas so that the runoff will naturally flow towards the subsurface infiltration beds.

The storage volume calculations for the Subsurface Infiltration Bed below are an example of what the calculations will look like for the proposed drain tile system. The calculations are only presented to show the approach, final design will require appropriate calculations that match the designed and installed subsurface network. The Storage Volume Reduction credit received from the BMPs will be equal to or greater than the Bankfull Volume Difference for each drainage area. The storage volume equation came from Section V, Part J in the WCWRC Rules. For this exercise, the following assumptions were made during the storage volume calculations. The infiltration area is the surface area of drainage material above the perforated pipes. The width of the infiltration area will be the width of the trench which is assumed to be 4' wide. The length of the infiltration area is equal to the length of the pipe. The depth of the underdrain material is the depth of the al above the pipe. This depth is assumed to be 1.67' because the er and the drainage material above the pipe is assumed to be 1'. T e void ratio of the drainage material above the pipe. The drainag % void ratio.

By meeting the infiltration requirement, you're also meeting and exceeding the bankfull vol difference, because the FF is greater than the bankfull vol diff. So you dont need to store these unless you cannot meet the infiltration volume.

Subsurface Infiltration Bed Storage Calculations:

Drainage Area 1:
Subsurface storage/infiltration bed volume = Infiltration area x Depth of underdrain material x Void ratio of storage material
Subsurface storage/infiltration bed volume = (4' * 1,253') * 1.67' * 0.3
Subsurface storage/infiltration bed volume = 2,511 ft^3
2,511 ft^3 is greater than the pre- and post-development bankfull difference for Drainage Area 1 that was calculated earlier, 1,916 ft^3, so the storage requirement is satisfied.

Drainage Area 2:
The difference between the pre-development bankfull volume and the post-development bankfull volume is zero, so no storage is required.

Drainage Area 3:
Subsurface storage/infiltration bed volume = Infiltration area x Depth of underdrain material x Void ratio of storage material
Subsurface storage/infiltration bed volume = (4' * 3,330') * 1.67' * 0.3
Subsurface storage/infiltration bed volume = 6,673 ft^3
6,673 ft^3 is greater than the pre- and post-development bankfull difference for Drainage Area 3 that was calculated earlier, 3,833 ft^3, so the storage requirement is satisfied.

A depiction of where the subsurface infiltration beds will be placed on the solar site can be seen in the Preliminary Stormwater Analysis Exhibit in **Attachment B**.

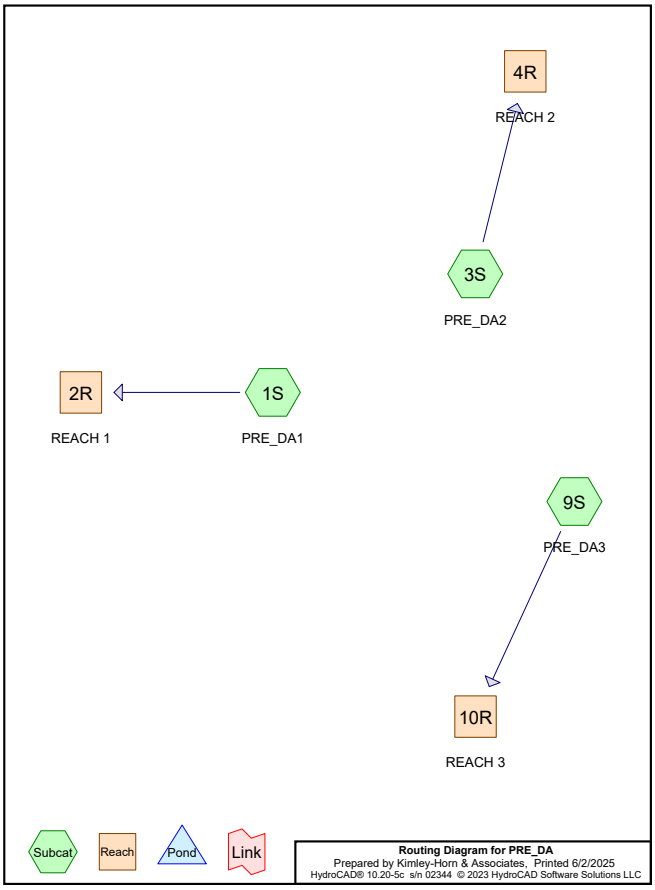
Executive Summary

The Washtenaw Solar facility will use Best Management Practices (BMPs) listed in the Washtenaw County Water Resources Commissioner (WCWRC) Rules and Guidelines to meet the stormwater requirements set forth by the County. Subsurface Infiltration Beds will be used to satisfy the Storage Volume requirement and Vegetative Filter Strips will be used to satisfy the Infiltration Volume requirement. Prior to final design of the BMPs, soil infiltration testing must be done on site using the soil infiltration testing guidelines in the WCWRC Rules and Guidelines.

Please do not hesitate to contact me if you have any questions. We appreciate your continued partnership on this project.

Calvin Carlson
Kimley-Horn of Michigan, Inc.
Calvin.Carlson@Kimley-Horn.com
331.310.0039

Attachment A – HydroCAD Report



Time span=5.00-20.00 hrs, dt=0.05 hrs, 301 points
Runoff by SCS TR-20 method, UH=SCS, Weighted-CN
Reach routing by Stor-Ind+Trans method - Pond routing by Stor-Ind method

Subcatchment1S: PRE_DA1 Runoff Area=11.970 ac 0.00% Impervious Runoff Depth>0.62"
Flow Length=895' Tc=25.3 min CN=78 Runoff=7.32 cfs 0.614 af

Subcatchment3S: PRE_DA2 Runoff Area=1.840 ac 0.00% Impervious Runoff Depth>0.62"
Flow Length=263' Tc=10.1 min CN=78 Runoff=1.85 cfs 0.095 af

Subcatchment9S: PRE_DA3 Runoff Area=25.230 ac 0.00% Impervious Runoff Depth>0.60"
Flow Length=2,193' Tc=61.3 min CN=78 Runoff=8.19 cfs 1.270 af

Reach 2R: REACH 1 Inflow=7.32 cfs 0.614 af
Outflow=7.32 cfs 0.614 af

Reach 4R: REACH 2 Inflow=1.85 cfs 0.095 af
Outflow=1.85 cfs 0.095 af

Reach 10R: REACH 3 Inflow=8.19 cfs 1.270 af
Outflow=8.19 cfs 1.270 af

Total Runoff Area = 39.040 ac Runoff Volume = 1.980 af Average Runoff Depth = 0.61"
100.00% Pervious = 39.040 ac 0.00% Impervious = 0.000 ac

Summary for Subcatchment 1S: PRE_DA1

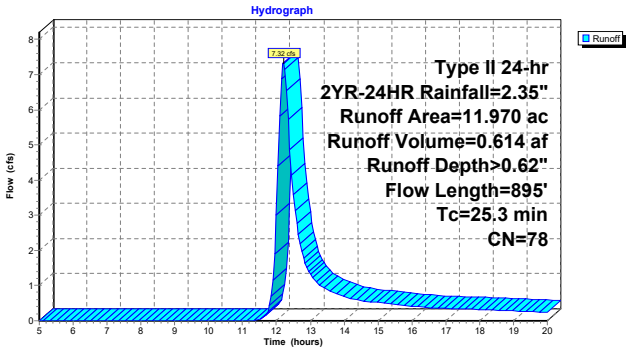
Runoff = 7.32 cfs @ 12.21 hrs, Volume= 0.614 af, Depth> 0.62"
Routed to Reach 2R : REACH 1

Runoff by SCS TR-20 method, UH=SCS, Weighted-CN, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs
Type II 24-hr 2YR-24HR Rainfall=2.35"

	Area (ac)	CN	Description
*	11.970	78	
	11.970		100.00% Pervious Area

Tc (min)	Length (feet)	Slope (ft/ft)	Velocity (ft/sec)	Capacity (cfs)	Description
10.2	100	0.0271	0.16		**Sheet Flow,** Grass: Short n= 0.150 P2= 2.31"
15.1	795	0.0157	0.88		**Shallow Concentrated Flow,** Short Grass Pasture Kv= 7.0 fps
25.3	895	Total			

Subcatchment 1S: PRE_DA1



Summary for Subcatchment 3S: PRE_DA2

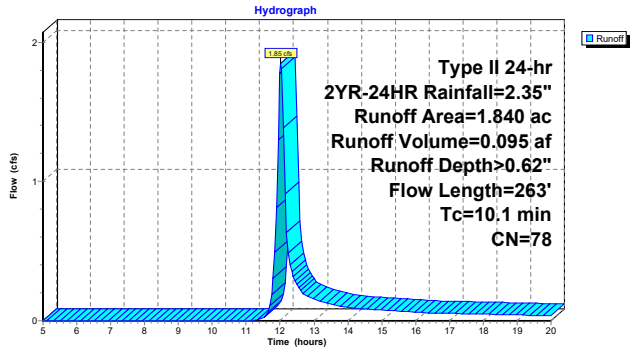
Runoff = 1.85 cfs @ 12.03 hrs, Volume= 0.095 af, Depth> 0.62"
Routed to Reach 4R : REACH 2

Runoff by SCS TR-20 method, UH=SCS, Weighted-CN, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs
Type II 24-hr 2YR-24HR Rainfall=2.35"

	Area (ac)	CN	Description
*	1.840	78	
	1.840		100.00% Pervious Area

Tc (min)	Length (feet)	Slope (ft/ft)	Velocity (ft/sec)	Capacity (cfs)	Description
8.1	100	0.0488	0.21		**Sheet Flow,** Grass: Short n= 0.150 P2= 2.31"
2.0	163	0.0390	1.38		**Shallow Concentrated Flow,** Short Grass Pasture Kv= 7.0 fps
10.1	263	Total			

Subcatchment 3S: PRE_DA2



Summary for Subcatchment 9S: PRE_DA3

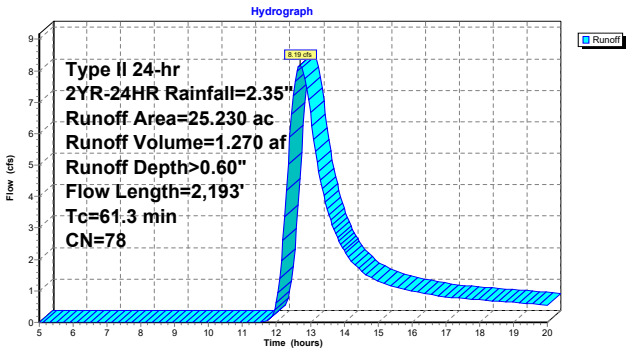
Runoff = 8.19 cfs @ 12.71 hrs, Volume= 1.270 af, Depth> 0.60"
Routed to Reach 10R : REACH 3

Runoff by SCS TR-20 method, UH=SCS, Weighted-CN, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs
Type II 24-hr 2YR-24HR Rainfall=2.35"

	Area (ac)	CN	Description
*	25.230	78	
	25.230		100.00% Pervious Area

Tc (min)	Length (feet)	Slope (ft/ft)	Velocity (ft/sec)	Capacity (cfs)	Description
8.8	100	0.0393	0.19		**Sheet Flow,** Grass: Short n= 0.150 P2= 2.31"
52.5	2,093	0.0090	0.66		**Shallow Concentrated Flow,** Short Grass Pasture Kv= 7.0 fps
61.3	2,193	Total			

Subcatchment 9S: PRE_DA3



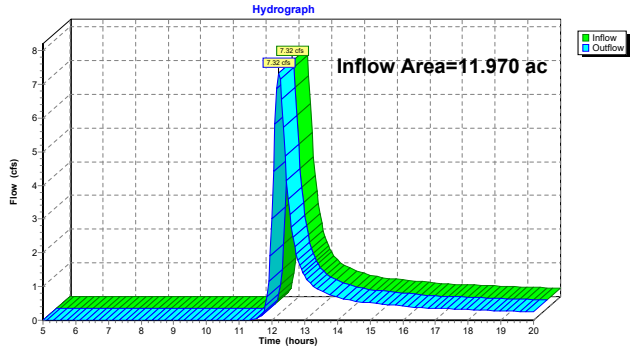
Summary for Reach 2R: REACH 1

[40] Hint: Not Described (Outflow=Inflow)

Inflow Area = 11.970 ac, 0.00% Impervious, Inflow Depth > 0.62" for 2YR-24HR event
Inflow = 7.32 cfs @ 12.21 hrs, Volume= 0.614 af
Outflow = 7.32 cfs @ 12.21 hrs, Volume= 0.614 af, Atten= 0%, Lag= 0.0 min

Routing by Stor-Ind+Trans method, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs

Reach 2R: REACH 1



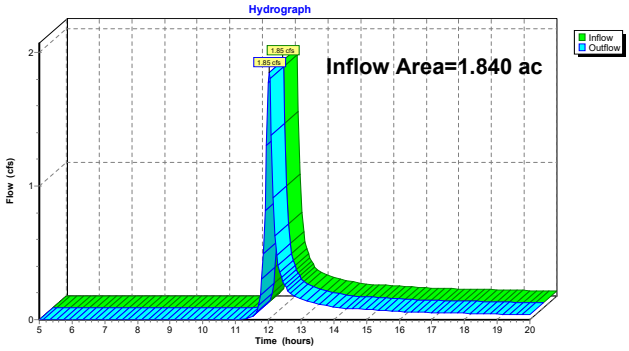
Summary for Reach 4R: REACH 2

[40] Hint: Not Described (Outflow=Inflow)

Inflow Area = 1.840 ac, 0.00% Impervious, Inflow Depth > 0.62" for 2YR-24HR event
Inflow = 1.85 cfs @ 12.03 hrs, Volume= 0.095 af
Outflow = 1.85 cfs @ 12.03 hrs, Volume= 0.095 af, Atten= 0%, Lag= 0.0 min

Routing by Stor-Ind+Trans method, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs

Reach 4R: REACH 2



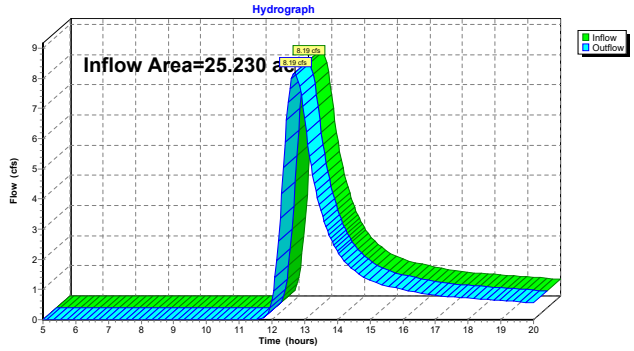
Summary for Reach 10R: REACH 3

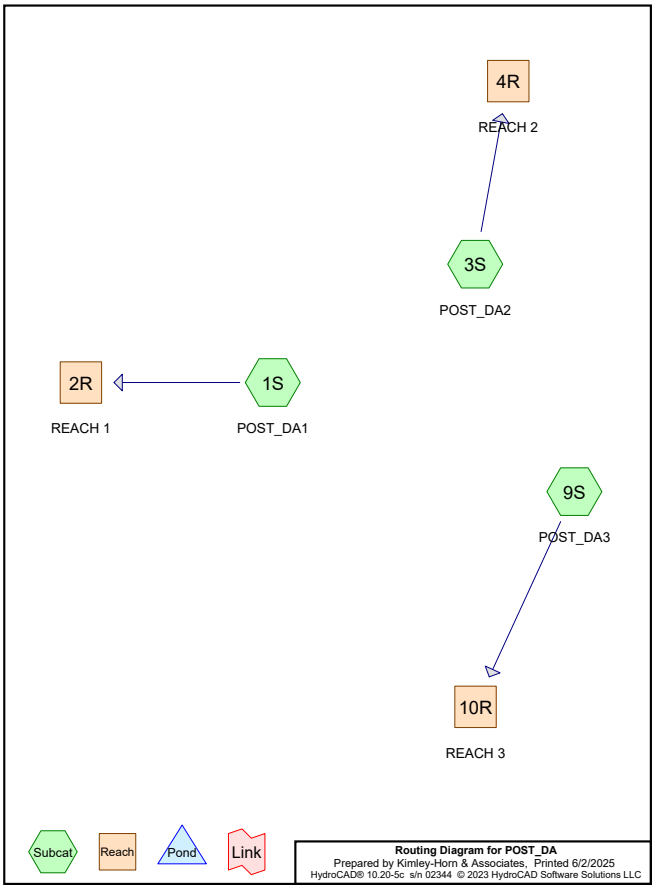
[40] Hint: Not Described (Outflow=Inflow)

Inflow Area = 25.230 ac, 0.00% Impervious, Inflow Depth > 0.60" for 2YR-24HR event
Inflow = 8.19 cfs @ 12.71 hrs, Volume= 1.270 af
Outflow = 8.19 cfs @ 12.71 hrs, Volume= 1.270 af, Atten= 0%, Lag= 0.0 min

Routing by Stor-Ind+Trans method, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs

Reach 10R: REACH 3





Time span=5.00-20.00 hrs, dt=0.05 hrs, 301 points
Runoff by SCS TR-20 method, UH=SCS, Weighted-CN
Reach routing by Stor-Ind+Trans method - Pond routing by Stor-Ind method

Subcatchment1S: POST_DA1 Runoff Area=11.970 ac 4.21% Impervious Runoff Depth>0.66"
Flow Length=895' Tc=24.4 min CN=79 Runoff=8.13 cfs 0.658 af

Subcatchment3S: POST_DA2 Runoff Area=1.840 ac 0.00% Impervious Runoff Depth>0.62"
Flow Length=263' Tc=10.1 min CN=78 Runoff=1.85 cfs 0.095 af

Subcatchment9S: POST_DA3 Runoff Area=25.230 ac 4.52% Impervious Runoff Depth>0.65"
Flow Length=2,193' Tc=64.2 min CN=79 Runoff=8.61 cfs 1.358 af

Reach 2R: REACH 1 Inflow=8.13 cfs 0.658 af
Outflow=8.13 cfs 0.658 af

Reach 4R: REACH 2 Inflow=1.85 cfs 0.095 af
Outflow=1.85 cfs 0.095 af

Reach 10R: REACH 3 Inflow=8.61 cfs 1.358 af
Outflow=8.61 cfs 1.358 af

Total Runoff Area = 39.040 ac Runoff Volume = 2.111 af Average Runoff Depth = 0.65"
95.79% Pervious = 37.396 ac 4.21% Impervious = 1.644 ac

Summary for Subcatchment 1S: POST_DA1

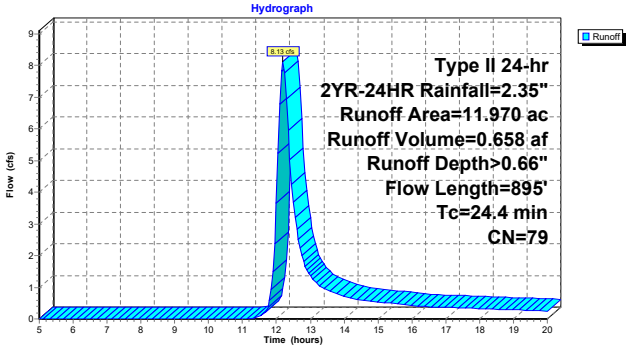
Runoff = 8.13 cfs @ 12.20 hrs, Volume= 0.658 af, Depth> 0.66"
Routed to Reach 2R : REACH 1

Runoff by SCS TR-20 method, UH=SCS, Weighted-CN, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs
Type II 24-hr 2YR-24HR Rainfall=2.35"

	Area (ac)	CN	Description
*	11.466	78	
*	0.504	98	
	11.970	79	Weighted Average
	11.466		95.79% Pervious Area
	0.504		4.21% Impervious Area

Tc (min)	Length (feet)	Slope (ft/ft)	Velocity (ft/sec)	Capacity (cfs)	Description
10.2	100	0.0271	0.16		**Sheet Flow,** Grass: Short n= 0.150 P2= 2.31"
2.3	173	0.0315	1.24		**Shallow Concentrated Flow,** Short Grass Pasture Kv= 7.0 fps
1.1	148	0.0122	2.24		**Shallow Concentrated Flow,** Paved Kv= 20.3 fps
10.8	474	0.0110	0.73		**Shallow Concentrated Flow,** Short Grass Pasture Kv= 7.0 fps
24.4	895	Total			

Subcatchment 1S: POST_DA1



Summary for Subcatchment 3S: POST_DA2

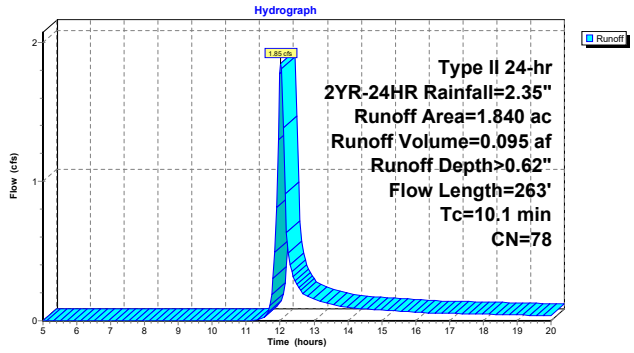
Runoff = 1.85 cfs @ 12.03 hrs, Volume= 0.095 af, Depth> 0.62"
Routed to Reach 4R : REACH 2

Runoff by SCS TR-20 method, UH=SCS, Weighted-CN, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs
Type II 24-hr 2YR-24HR Rainfall=2.35"

	Area (ac)	CN	Description
*	1.840	78	
	1.840		100.00% Pervious Area

Tc (min)	Length (feet)	Slope (ft/ft)	Velocity (ft/sec)	Capacity (cfs)	Description
8.1	100	0.0488	0.21		**Sheet Flow,** Grass: Short n= 0.150 P2= 2.31"
2.0	163	0.0390	1.38		**Shallow Concentrated Flow,** Short Grass Pasture Kv= 7.0 fps
10.1	263	Total			

Subcatchment 3S: POST_DA2



Summary for Subcatchment 9S: POST_DA3

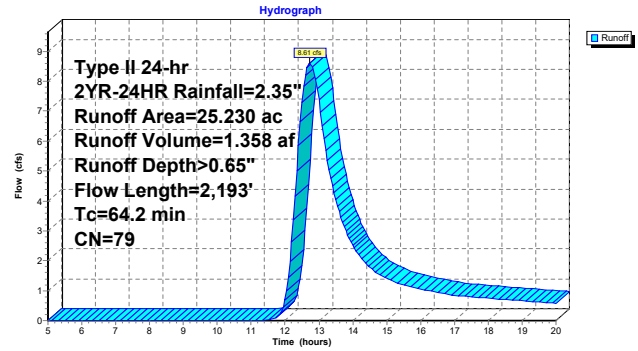
Runoff = 8.61 cfs @ 12.74 hrs, Volume= 1.358 af, Depth> 0.65"
Routed to Reach 10R : REACH 3

Runoff by SCS TR-20 method, UH=SCS, Weighted-CN, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs
Type II 24-hr 2YR-24HR Rainfall=2.35"

	Area (ac)	CN	Description
*	24.090	78	
*	1.140	98	
	25.230	79	Weighted Average
	24.090		95.48% Pervious Area
	1.140		4.52% Impervious Area

Tc (min)	Length (feet)	Slope (ft/ft)	Velocity (ft/sec)	Capacity (cfs)	Description
8.8	100	0.0393	0.19		**Sheet Flow,** Grass: Short n= 0.150 P2= 2.31"
18.6	709	0.0082	0.63		**Shallow Concentrated Flow,** Short Grass Pasture Kv= 7.0 fps
0.4	20	0.0020	0.91		**Shallow Concentrated Flow,** Paved Kv= 20.3 fps
26.1	814	0.0055	0.52		**Shallow Concentrated Flow,** Short Grass Pasture Kv= 7.0 fps
0.2	20	0.0100	2.03		**Shallow Concentrated Flow,** Paved Kv= 20.3 fps
10.1	530	0.0155	0.87		**Shallow Concentrated Flow,** Short Grass Pasture Kv= 7.0 fps
64.2	2,193	Total			

Subcatchment 9S: POST_DA3



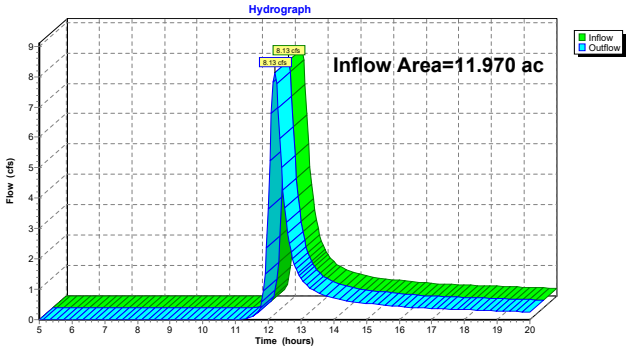
Summary for Reach 2R: REACH 1

[40] Hint: Not Described (Outflow=Inflow)

Inflow Area = 11.970 ac, 4.21% Impervious, Inflow Depth > 0.66" for 2YR-24HR event
Inflow = 8.13 cfs @ 12.20 hrs, Volume= 0.658 af
Outflow = 8.13 cfs @ 12.20 hrs, Volume= 0.658 af, Atten= 0%, Lag= 0.0 min

Routing by Stor-Ind+Trans method, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs

Reach 2R: REACH 1



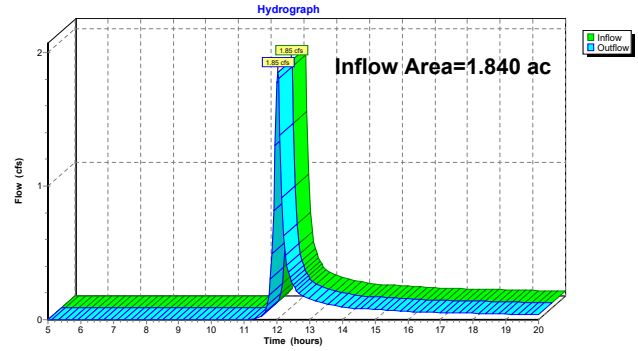
Summary for Reach 4R: REACH 2

[40] Hint: Not Described (Outflow=Inflow)

Inflow Area = 1.840 ac, 0.00% Impervious, Inflow Depth > 0.62" for 2YR-24HR event
Inflow = 1.85 cfs @ 12.03 hrs, Volume= 0.095 af
Outflow = 1.85 cfs @ 12.03 hrs, Volume= 0.095 af, Atten= 0%, Lag= 0.0 min

Routing by Stor-Ind+Trans method, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs

Reach 4R: REACH 2



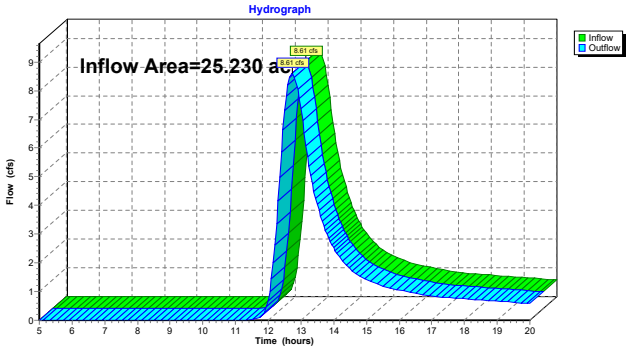
Summary for Reach 10R: REACH 3

[40] Hint: Not Described (Outflow=Inflow)

Inflow Area = 25.230 ac, 4.52% Impervious, Inflow Depth > 0.65" for 2YR-24HR event
Inflow = 8.61 cfs @ 12.74 hrs, Volume= 1.358 af
Outflow = 8.61 cfs @ 12.74 hrs, Volume= 1.358 af, Atten= 0%, Lag= 0.0 min

Routing by Stor-Ind+Trans method, Time Span= 5.00-20.00 hrs, dt= 0.05 hrs

Reach 10R: REACH 3



Attachment B – Preliminary Stormwater Analysis Exhibit

Where are these areas going and what's the stormwater management for these areas? Make sure the entire site is accounted for

What does this crossing look like? Is there a culvert anywhere?

NORTH

GRAPHIC SCALE IN FEET
0 50 100 200

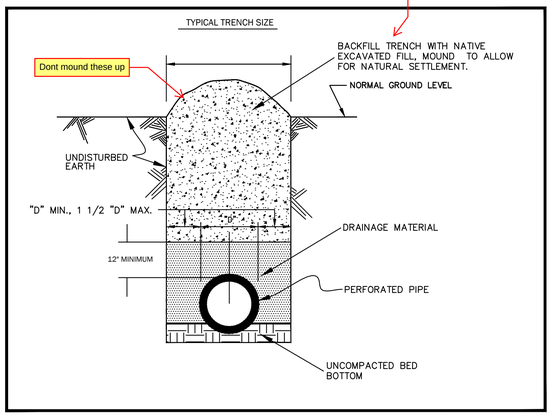
LEGEND

PROPERTY LINE	
PROPERTY LINE SETBACK	
EX. CONTOURS	XXX
EX. FLOW DIRECTION AND SLOPE	XX%
EX. DRAIN TILE	
EX. CONCENTRATED FLOW LINE	
DRAINAGE AREA	
PR. GRAVEL ACCESS ROAD	
PR. PANELS	
PR. PANEL LIMITS	
PR. INVERTER	
PR. FENCE	X X X X
PR. LIMITS OF DISTURBANCE	LoD LoD LoD
PR. VEGETATIVE FILTER STRIP	
PR. SUBSURFACE INFILTRATION BED	

NOTES

1. SEE DETAIL 1, THIS SHEET FOR SUBSURFACE INFILTRATION BED.
2. THIS EXHIBIT IS FOR COORDINATION WITH WASHTENAW COUNTY ONLY AND NOT TO BE USED FOR CONSTRUCTION OR PERMITTING.

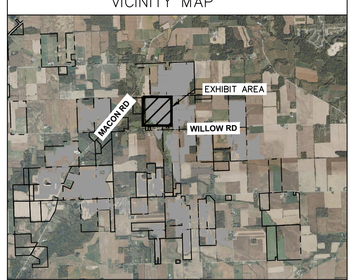
I'd use sand if we're in clayey ground. Otherwise, these wont be functional



1
EX-1
SUBSURFACE INFILTRATION BED

SCALE: NTS

VICINITY MAP



NOT TO SCALE

No.	REVISIONS	DATE

Invenergy

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DEERFIELD, IL 60015 (847) 260-7804
WWW.KIMLEY-HORN.COM

PRELIMINARY NOT FOR CONSTRUCTION

KHA PROJECT 168754131
DATE 06/10/2025
AS SHOWN
DESIGNED BY JLE
DRAWN BY JLE
CHECKED BY CPC

PRELIMINARY STORMWATER ANALYSIS EXHIBIT

WASHTENAW SOLAR
WASHTENAW COUNTY, MI

SHEET NUMBER
EX-1

Drawing name: K:\CHS_LDEV\168754131_Invenergy_Washtenaw_MI\2 Design\CAD\Exhibits\Drainage Map\Alternative Stormwater Exhibit.dwg EX-1 Jun 10, 2025 5:25pm by: jenna.Elliott
This document, together with the concepts and designs presented herein, as an instrument of service, is intended only for the specific purpose and client for which it was prepared. Reuse of and improper reliance on this document without written authorization and adaptation by Kimley-Horn and Associates, Inc. shall be without liability to Kimley-Horn and Associates, Inc.

Invenergy

Signal Mitigation

Exhibit A-7 (TSD-9)

PREPARED FOR:

WASHTENAW SOLAR ENERGY LLC

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Invenergy

1.0 Introduction

Washtenaw Solar Energy LLC ("Washtenaw Solar") is developing a 150 MW solar energy facility located in Saline Township, Washtenaw County, Michigan ("Project"). The Michigan Public Service Commission's Filing Guidelines require that, "[i]f the facility is reasonably expected to have an impact on television signals, microwave signals, agricultural global position systems, military defense radar, radio reception, or weather and doppler radio, provide a plan to minimize and mitigate that impact." Filing Guidelines, Section 6.3.7.

The letter included as **Appendix A** confirms that no such impacts are expected from the Project. The Department of Energy guidelines regarding solar siting to avoid interference are included as **Appendix B**. No airfield navigational, communication, or radar systems are located within the Project Area. Accordingly, no plan is included in Washtenaw Solar's application.

Appendices

2.0 Appendices

Appendix A: Letter Confirming No Signal Interference

Michigan Public Service Commission
7109 W Saginaw Hwy
Lansing, MI 48917

Re: Signal Mitigation Plan for Invenergy's Washtenaw Solar, an Invenergy Energy Project

Dear Michigan Public Service Commission:

I am reaching out regarding Washtenaw Solar Energy LLC ("Washtenaw Solar") proposed 150 MW solar facility proposed on privately-owned land within Saline Township, Washtenaw County, Michigan (the "Project").

As of the date of this application, Washtenaw Solar has not identified any evidence or occurrences of utility-scale solar sites interfering with or impacting any communication systems. The height of the proposed solar panels will be no more than 25 feet above ground when the arrays are at full tilt, which is shorter than a 1-story structure, and therefore would be unlikely to interfere with line-of-sight communications. The Project is not expected to have an impact on television signals, microwave signals, agricultural global position systems, military defense radar, radio reception, or weather and doppler radio. Therefore, the Project needs no signal mitigation plan.

If you have any questions or would like additional details, please feel free to contact me at jbarbee@invenergy.com.

Best regards,

Jim Barbee
Senior Manager, Renewable Electrical Engineering
Invenergy
1 S. Wacker Dr. Ste. 1500
Chicago, IL 60606

Appendix B: United States Department of Energy Review of Electro-Magnetic Interference from Solar Photovoltaic Arrays

U.S. DEPARTMENT OF THE NAVY
REPO
RENEWABLE ENERGY PROGRAM OFFICE

greenfleet.dodlive.mil/energy/repo

Electro-Magnetic Interference from Solar Photovoltaic Arrays

While the risk of electro-magnetic and/or radar interference from PV systems is very low, it does merit evaluation, if only to improve the confidence of site owners and other stakeholders.

Electro-Magnetic Interference

Electro-magnetic interference (EMI) is typically taken to mean radiofrequency (RF) emissions emanating from PV systems impacting nearby radio receivers, but can also include interference with communication devices, navigational aids, and explosives triggers.

The Federal Aviation Admiration (FAA) has indicated that EMI from PV installations is low risk. PV systems equipment such as step-up transformers and electrical cables are not sources of electromagnetic interference because of their low-frequency (60 Hz) of operation and PV panels themselves do not emit EMI. The only component of a PV array that may be capable of emitting EMI is the inverter. Inverters, however, produce extremely low frequency EMI similar to electrical appliances and at a distance of 150 feet from the inverters the EM field is at or below background levels. Also proper inverter enclosure grounding, filtering, and circuit layout further reduce EM radiation.

Photovoltaic inverters are inherently low-frequency devices that are not prone to radiating EMI. No interference is expected above 1 MHz because of the inverters' low-frequency operation. In addition, interaction at lower frequencies (100 kHz to1 MHz) is also very low risk because of the poor coupling of these extremely long wavelengths to free space, limiting propagation of the signal.

Additionally, the Code of Federal Regulations, Title 47, Part 15 regulates radio frequency (RF) emission from commercial products and many PV inverter manufacturers do qualify their residential or utility-scale equipment to this standard.

Radar Interference

Another concern is blocking or attenuation of nearby radar by the PV array, which are similar to other non-transmitting built structure like building or sheds in that they are constructed of metal and glass.

PV arrays have low profiles (i.e. height) relative to most built structures that may be found on or around airfields and in general airport radar systems (e.g., airport surveillance radar) are installed on elevated platforms or towers. The FAA has published a number of case studies that indicate that a setback of 250' to 500' between the leading edges of a PV array and existing radar equipment is sufficient to prevent blocking and/or signal reflection issues.

Siting Considerations

When considering sites for a PV array in close proximity to airfield navigational instruments or communications the tolerance of the equipment to EMI and susceptibility to radar signal blocking/attenuation should be considered. Fortunately, both of these concerns have been researched and vetted by the FAA and industry, and the following specifications should be applied:

1. PV system inverters should be sited at least 150' away from navigational and communications equipment that may be sensitive to EMI.
2. A minimum setback distance of 250' should be imposed between an airfields radar system and the leading edge of a PV array or any of its ancillary support equipment.

In the unlikely event that a PV array was to be built within the EMI setback distance, options are available to address interference if it were to occur. Inductor-capacitor (LC) filters can be installed to attenuate RF emissions at specific frequencies causing undesired interaction. Grounding of PV conductors either directly or via the inverter can also attenuate undesired RF emissions.

Additional Considerations

Where the FAA has identified interactions between PV systems and aircraft communication, this was often due to the prototype nature of the PV equipment in question. Some power electronics equipment operates at a higher frequency than we have discussed so far. This can be because the inverter uses advanced wide-bandgap semiconductors such as Silicon Carbide (SiC) or Gallium Nitride (GaN). Alternatively, the power electronics could be embedded within the PV module, which can enable or require a high switching frequency. In either case, these types of power conversion devices should be assessed for compliance with FCC emission limits, just as a conventional PV inverter would be.

As an illustration of the relative low allowable FCC limits, we can compare the maximum emission allowed for a FCC class-A compliant inverter with a typical cell phone. The maximum expected field strength for this inverter at a distance of 100' is very low- comparable to the field strength of a cell phone a mile away, and unlikely to be distinguishable from background noise.

In conclusion, with diligent procurement and siting of PV system components, including specifications for FCC Part 15 compliant equipment and observation of minimum setbacks from potentially sensitive equipment, it is unlikely that a PV system will cause negative interactions with existing equipment or operations.

"Due to their low profiles, solar PV systems typically represent little risk of interfering with radar transmissions. In addition, solar panels do not emit electromagnetic waves over distances that could interfere with radar signal transmissions, and any electrical facilities that do carry concentrated current are buried beneath the ground and away from any signal transmission." - FAA Solar Guide.

"Prior research and field investigations of electromagnetic emission (EME) from Solar PV arrays concluded that they produce extremely low frequency EME similar to electrical appliances and wiring.…At a distance of 150 feet from the inverters, these fields dropped back to very low levels of 0.5 mG or less, and in many cases to much less than background levels (<0.2 mG)." - Air Force Tiger Team investigation.

Useful References

1. Air Force Civil Engineering Center, Planning and Integration Directorate, Regional Planning Development Branch. 2014. Solar PV Compatibility Project Tiger Team.
2. Federal Aviation Administration (FAA). 2010. Technical Guidance for Evaluating Selected Solar Technologies at Airports. FAA-Office of Airports, Washington, DC. https:/ www.faa.gov/airports/environmental/policy_guidance/ media/airport-solar-guide-print.pdf.
3. Araneo, R., S. Lammens, M. Grossi, and S. Bertone, S. 2009. "EMC issues in high-power grid-connected photovoltaic plants," *IEEE Transactions on Electromagnetic Compatibility, 51*(3), 639-648.
4. Di Piazza, M.C., G. Tine, C. Serporta, and G. Vitale. 2004. "Electromagnetic compatibility characterization of the DC side in a low power photovoltaic plant," in *Proc. IEEE Int. Conf. Ind. Tech.*, pp. 672–6.

CONTACT INFORMATION
For more information, contact Chris Deline, Sr. Engineer, chris.deline@nrel.gov, 303-384-6359 or Steven Phillips, Project Manager, steven.l.phillips@navy.mil, 757-322-4029.

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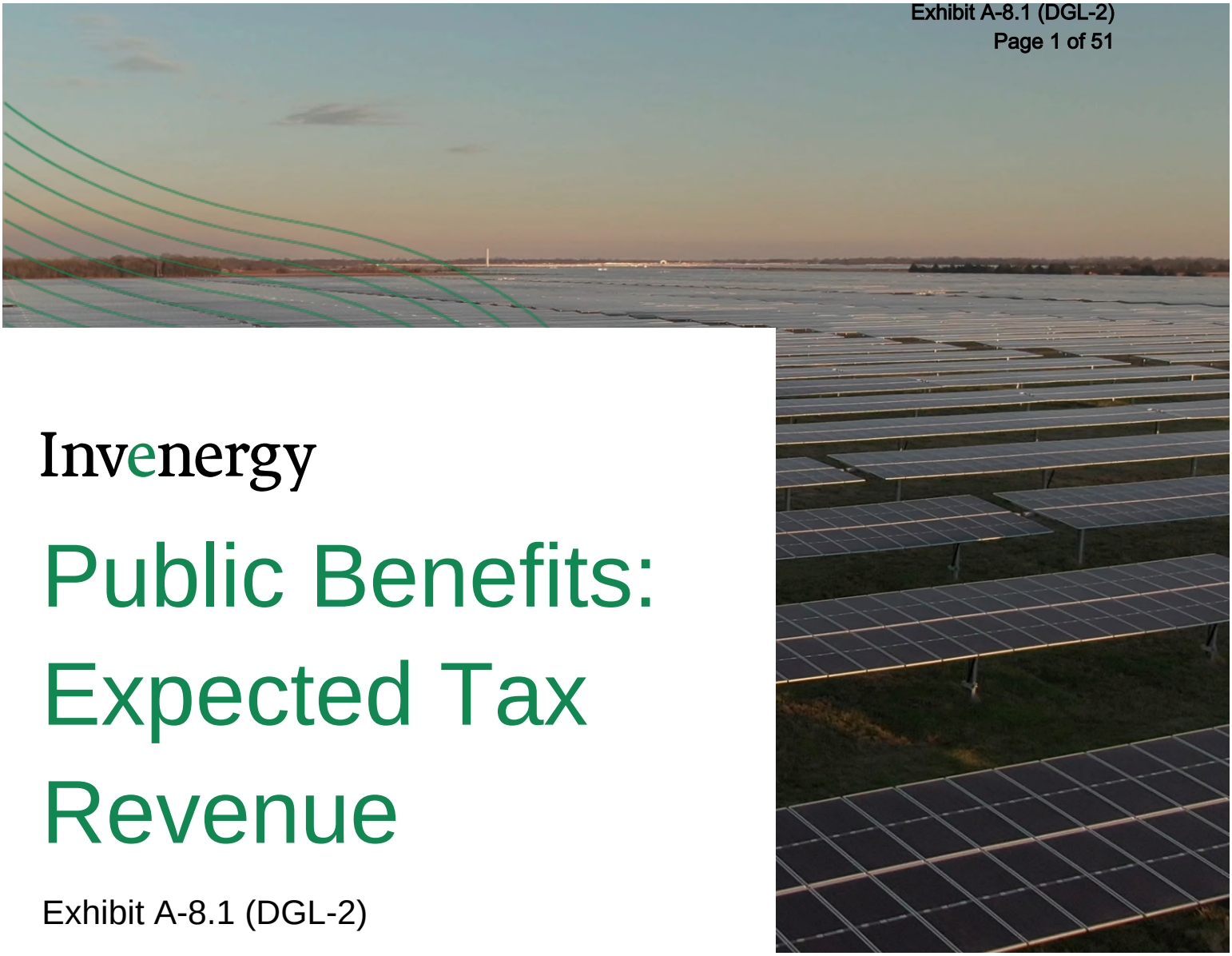
NREL/FS-5J00-67440 • www.navy.mil • April 2017



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Public Benefits: Expected Tax Revenue

Exhibit A-8.1 (DGL-2)

PREPARED FOR:

WASHTENAW SOLAR ENERGY LLC

Invenergy

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1.0 Introduction

Washtenaw Solar Energy LLC ("Washtenaw Solar") is proposing a 150 MW solar energy facility in Saline Township, Washtenaw County, Michigan (the "Project"). Washtenaw Solar worked with Strategic Economic Research, LLC to prepare a report detailing the economic impacts and public benefits of the Project. This report, detailing the expected tax revenue paid by Washtenaw Solar to local taxing districts, is included as **Appendix A**. This report also details job creation, economic development, and economic benefits from the Project. These economic benefits detailed in the report demonstrate how the public benefits of the Project justify its construction. These benefits would not materialize without the construction of the Project.

Appendix

2.0 Appendix

Appendix A: Economic Impact Analysis

Strategic Economic Research, LLC

ECONOMIC IMPACT ANALYSIS OF THE WASHTENAW SOLAR PROJECT

July 2025

Dr. David G. Loomis, Bryan Loomis, and Chris Thankan

Strategic Economic Research, LLC
strategiceconomic.com
815-905-2750

About the Authors

Dr. David G. Loomis

President of Strategic Economic Research, LLC
Professor Emeritus of Economics,
Illinois State University
Co-Founder of the Center for Renewable Energy

Dr. David G. Loomis is Professor Emeritus of Economics at Illinois State University and Co-Founder of the Center for Renewable Energy. He has over 20 years of experience in the renewable energy field. He has served as a consultant for 43 renewable energy development companies. He has testified on the economic impacts of energy projects before the Illinois Commerce Commission, Indiana Utility Regulatory Commission, Iowa Utilities Board, Kentucky State Board on Electric Generation and Transmission Siting, Louisiana Public Service Commission, Mississippi Public Service Commission, Missouri Public Service Commission, New Mexico Public Regulation Commission, Ohio Power Siting Board, the Public Service Commission of West Virginia, Public Service Commission of Wisconsin, and numerous county boards. Dr. Loomis, a widely recognized expert, has appeared on CNN and been quoted in the Wall Street Journal, Forbes Magazine, Associated Press, and the Chicago Tribune.

Dr. Loomis has published 40 peer-reviewed articles in leading energy policy and economics journals. He has raised and managed over $7 million in grants and contracts from government, corporate, and foundation sources. He received the 2011 Department of Energy's Midwestern Regional Wind Advocacy Award and the 2006 Best Wind Working Group Award. Dr. Loomis received his Ph.D. in Economics from Temple University in 1995.

Bryan Loomis, MBA

Vice President of Strategic Economic Research, LLC

Bryan Loomis has been conducting economic impact, property tax, and land use analyses for Strategic Economic Research since 2019. He has performed or overseen over 200 wind and solar analyses and provided expert testimony for permitting hearings and open houses in many states, including Colorado, Kansas, Indiana, Illinois, and Iowa. He improved the property tax analysis methodology at SER by researching various state taxing laws, implementing depreciation and taxing jurisdiction millage rates, and incorporating other factors into the tax analysis tool. Before working with SER, Bryan ran a consulting agency that collaborated with over 30 technology startups on their growth and marketing strategies. Bryan received his MBA from Belmont University in 2016.

Christopher Thankan

Director of Economic Impact Analysis
Strategic Economic Research, LLC

Christopher Thankan directs the production of the economic impact studies including sourcing, analyzing, and graphing government data. He also performs economic and property tax analyses for wind, solar, and transmission projects. Chris has a Bachelor of Science degree in Sustainable & Renewable Energy and minored in Economics.

Strategic Economic Research, LLC (SER) provides economic consulting for renewable energy projects across the U.S. We have produced over 400 economic impact reports in over 35 states. Research Associates who performed work on this project include Paige Afram, Amanda Battaglia, Lindsey Cohn, Sawyer Keithley, Clara Lewis, Ethan Loomis, Hannah Loomis, Nita Loomis, Jessica Lucht, Mandi Mitchell, Russell Piontek, Isabelle Piwowarczyk, Tim Roberts, Krista Rust, and Ashley Thompson.

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I. Executive Summary

Invenergy is developing the Washtenaw Solar Project in Washtenaw County, Michigan. The purpose of this report is to aid decision makers in evaluating the economic impacts of this project on Washtenaw County and the State of Michigan. The basis of this analysis is to study the direct, indirect, and induced impacts on job creation, wages, and total economic output.

The Washtenaw Solar Project is a 150-megawatt alternating current (MWac) utility-scale solar powered-electric generation facility that will utilize photovoltaic (PV) panels installed on a single-axis tracking system. The total Project represents an investment in excess of $237 million. The total development is anticipated to result in the following:

Economic Impacts

Jobs[1]

- 251 new local jobs during construction for Washtenaw County
- 438 new local jobs during construction for the State of Michigan
- 13.1 new local long-term jobs for Washtenaw County
- 18.2 new local long-term jobs for the State of Michigan

Output[3]

- Over $50.6 million in new local output during construction for Washtenaw County
- Over $92.4 million in new local output during construction for the State of Michigan
- Over $2.1 million in new local long-term output for Washtenaw County annually
- Over $3.0 million in new local long-term output for the State of Michigan annually

Earnings[2]

- Over $24.7 million in new local earnings during construction for Washtenaw County
- Over $41.2 million in new local earnings during construction for the State of Michigan
- Over $948 thousand in new local long-term earnings for Washtenaw County annually
- Over $1.3 million in new local long-term earnings for the State of Michigan annually

Tax-Benefits

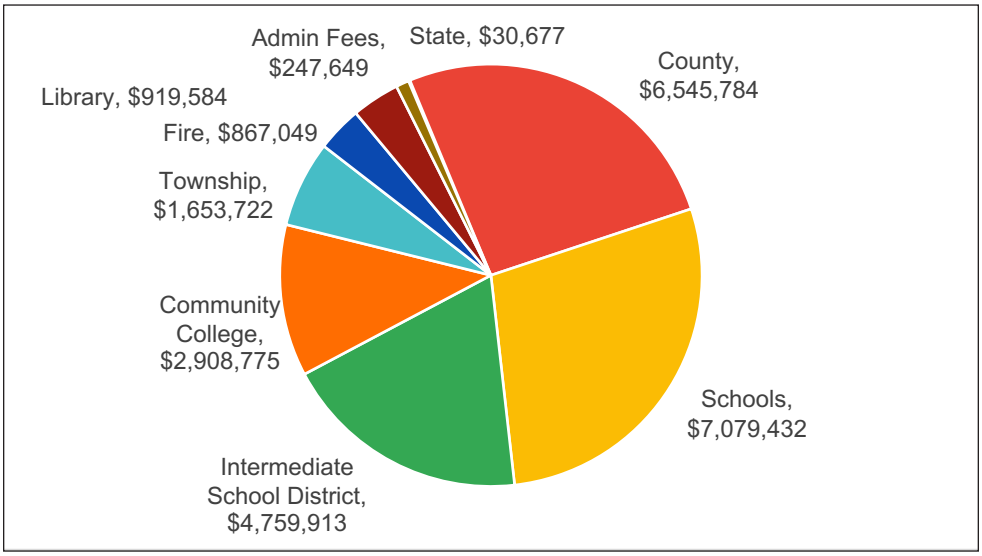
- Over $7.0 million in total school district property taxes over the life of the Project
- Over $6.5 million in total county property taxes for Washtenaw County over the life of the Project
- Over $25.0 million in total property taxes for all taxing districts over the life of the Project

[1] All jobs values are full-time equivalents (FTEs) and are the sum of the direct, indirect, and induced jobs during construction and annual operations which can be found in the Economic Impact Results section.

[2] Earnings are a measurement in dollars of the total wages and benefits given to the jobs estimated by the economic impact modeling software.

[3] The value of production in the state or local economy. It is an equivalent measure to the Gross Domestic Product.

Figure 1.1 – Total Property Taxes Paid by the Washtenaw Solar Project

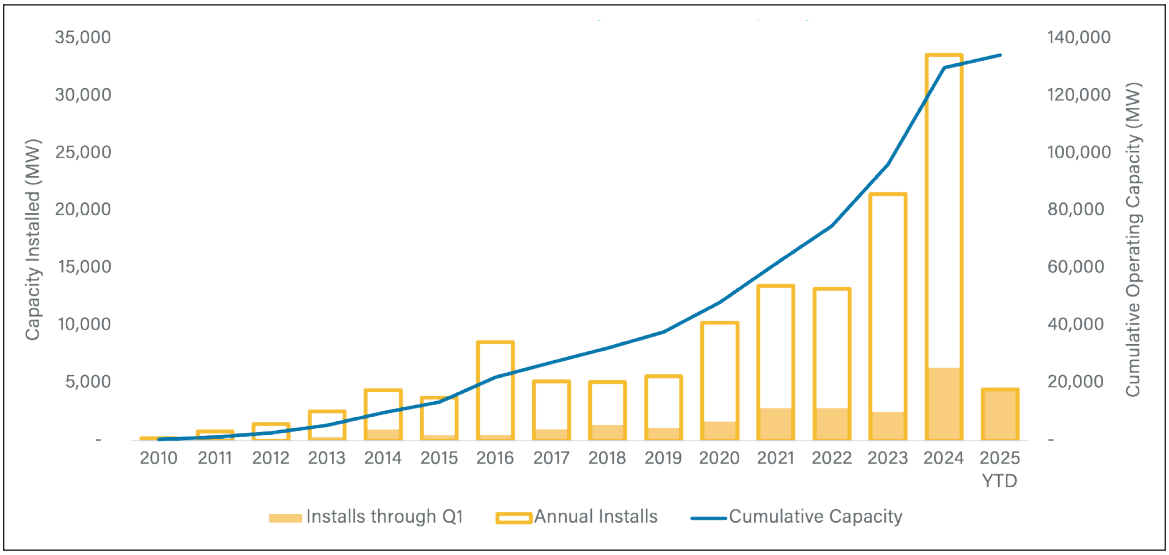


a. U.S. Solar PV Industry Growth

The U.S. solar industry is growing at a rapid but uneven pace. Solar energy systems are installed for on-site use — including residential, commercial, and industrial properties — and utility-scale solar-powered electric generation facilities intended for wholesale distribution. The PROJECTNAME is a utility-scale solar PV project intended for wholesale markets through the transmission grid. From 2013 to 2018, the amount of solar-generated electricity more than quadrupled, increasing by 444% (SEIA, 2020). The industry has continued to add PV systems to the grid. Figure 2.1 shows the historical capacity additions. The primary driver of this overall sharp pace of growth is large price declines in solar equipment. According to Figure 2.2, utility-scale solar fixed tilt and single-axis tracking have decreased from an average of $6/watt in 2010 to slightly more than $1/watt in 2023. Solar PV also benefits from the Federal Investment Tax Credit (ITC), which provides a tax credit for residential and commercial properties.

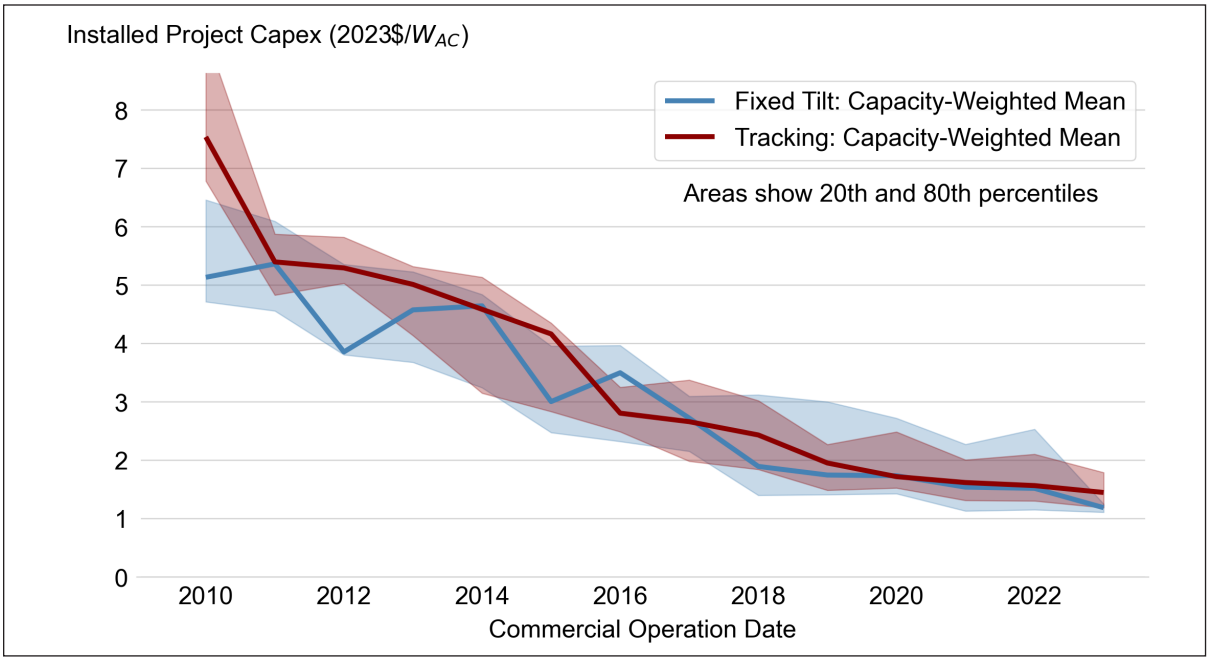
According to Figure 2.3, utility-scale PV installations jumped in the fourth quarter of 2024 to over 16,000 MWdc. Even with this large ramp-up of installations, there are an additional 60,000 MWdc of contracted utility-scale installations that have yet to be built.

Figure 2.1 – U.S. Annual and Cumulative Utility-Scale Solar Capacity Growth, 2010 - Q1, 2025



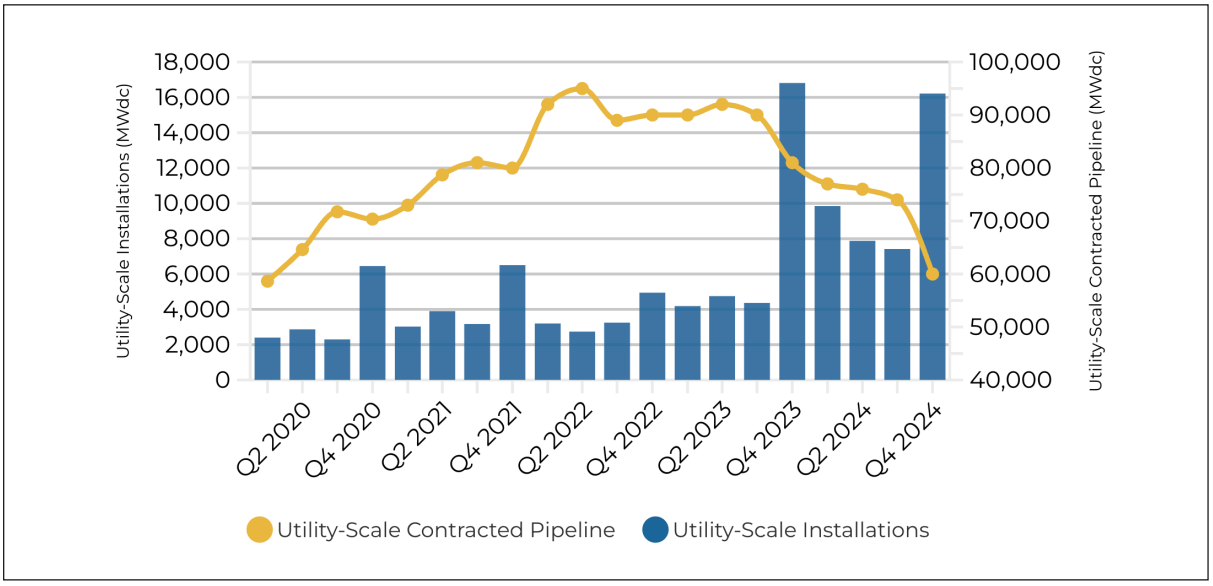
Source: ACP, Clean Power Market Report, Q1 2025

Figure 2.2 – Installed Costs of Utility-Scale Solar from 2010 to 2023 (adjusted for inflation)



Source: Lawrence Berkeley National Laboratory, Utility-Scale Solar, 2024 Edition

Figure 2.3 – U.S. Utility PV Installations vs. Contracted Pipeline



Source: Solar Energy Industries Association, Solar Market Insight Report Q4 2024

b. Michigan Solar PV Industry

According to the Solar Energy Industries Association (SEIA), Michigan is ranked 25th in the U.S. cumulative installations of solar PV. Texas, California, and Florida are the top 3 states for utility-scale solar PV which may not be surprising because of the high solar irradiation that they receive (ACP, Q1, 2025). However, there are other states with similar solar irradiation to Michigan that rank highly for utility-scale solar. In 2024, Michigan installed 500.55 MW of solar electric capacity bringing its cumulative capacity to 2,100.45 MW.

Michigan has great potential to expand its solar installations. Table 2.1 has a list of the operational utility-scale solar farms in operation in Michigan through 2025 (some small projects below 15 MW were omitted from the table). The 150 MW Washtenaw Solar Project will be one of the largest installations in Michigan to date. (The megawatts listed in this paragraph are MWac. To convert to MWdc, multiply the MWac by 1.3 to get the approximate MWdc capacity.)

There are 198 solar companies in Michigan including 66 manufacturers, 73 installers/developers, and 59 others ("other" includes sales and distribution, project management, and engineering). Figure 2.4 shows the locations of solar companies in Michigan as of the time of this report. Currently, there are 4,329 solar jobs in the State of Michigan according to SEIA.

Figure 2.5 shows the Michigan historical installed capacity by year according to the SEIA. Solar installation saw huge growth in 2023 and 2024 and is forecasted to continue to grow. Over the next five years, solar in Michigan is projected to grow by 5,626 MW.

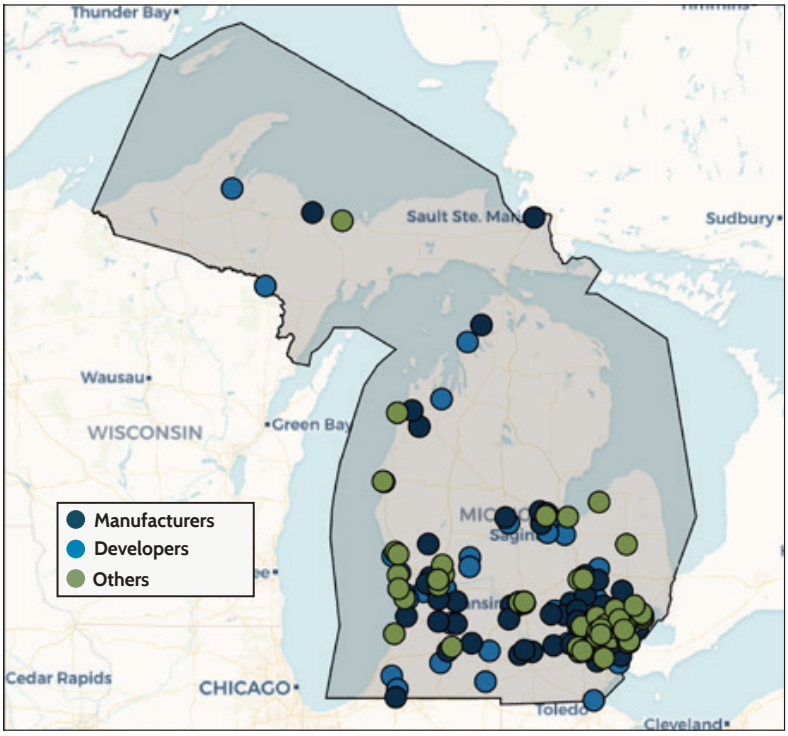
The Energy Information Administration (EIA) calculated the number of megawatt-hours generated from different energy sources in 2023. As shown in Figure 2.6, the greatest percentage of electricity generated in Michigan came from natural gas with 45.7% followed by nuclear energy with 22.8% and coal with 19.2%. Approximately 1.1% of the total electricity power generated in Michigan came from solar thermal and solar PV in 2023.

The U.S. Department of Energy sponsors the U.S. Energy and Employment Report each year. Electric Power Generation covers all utility and non-utility employment across electric generating technologies, including fossil fuels, nuclear, and renewable technologies. It also includes employees engaged in facility construction, turbine and other generation equipment manufacturing, operations and maintenance, and wholesale parts distribution for all electric generation technologies. According to Figure 2.7, employment in Michigan in the solar energy industry (5,643) is larger than traditional hydroelectricity generation (5,192), wind electric generation (5,188) and natural gas generation (3,826).

Table 2.1 – Michigan Solar Projects

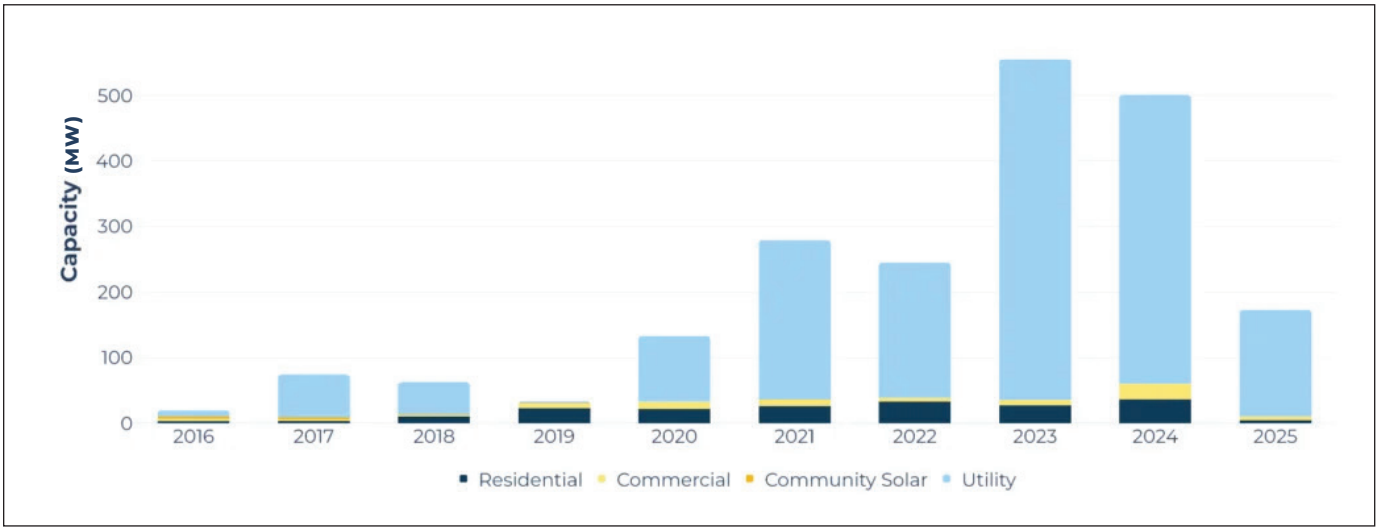
Utility-Scale Solar Farm	Capacity (MW)	County Name	Year Online
Demille Solar Farm	28.56	Lapeer County	2017
Turrill Solar Farm	19.72	Lapeer County	2017
Delta Solar Power I	24	Eaton County	2018
Assembly Solar Project	239	Shiawassee County	2020
Bingham Solar	20	Clinton County	2021
Temperance Solar, LLC	20	Monroe County	2021
Cement City Solar	20	Jackson County	2022
Lyons Road Solar Farm	20	Shiawassee County	2022
Macbeth Solar	20	Muskegon County	2022
Pullman Solar	20	Allegan County	2022
Letts Creek Solar Project	15	Jackson County	2022
Calhoun Solar Energy Center	200	Calhoun County	2023
Cereal City Solar	100	Calhoun County	2023
Blue Elk Solar	72.5	Genesee County	2023
Greenstone Solar	20	Branch County	2023
Midcontinent Solar Project	20	Shiawassee County	2023
Shipsterns Solar	20	Calhoun County	2023
Willford Solar	20	Gladwin County	2023
River Fork Solar Project	149	Calhoun County	2024
Calhoun County Solar Project	125	Calhoun County	2024
Holcim - Alpena Solar Project	25	Alpena County	2024
Surbrook Solar	20	Jackson County	2024
Sauk Solar	150	Branch County	2025

Figure 2.4 – Solar Company Locations in Michigan



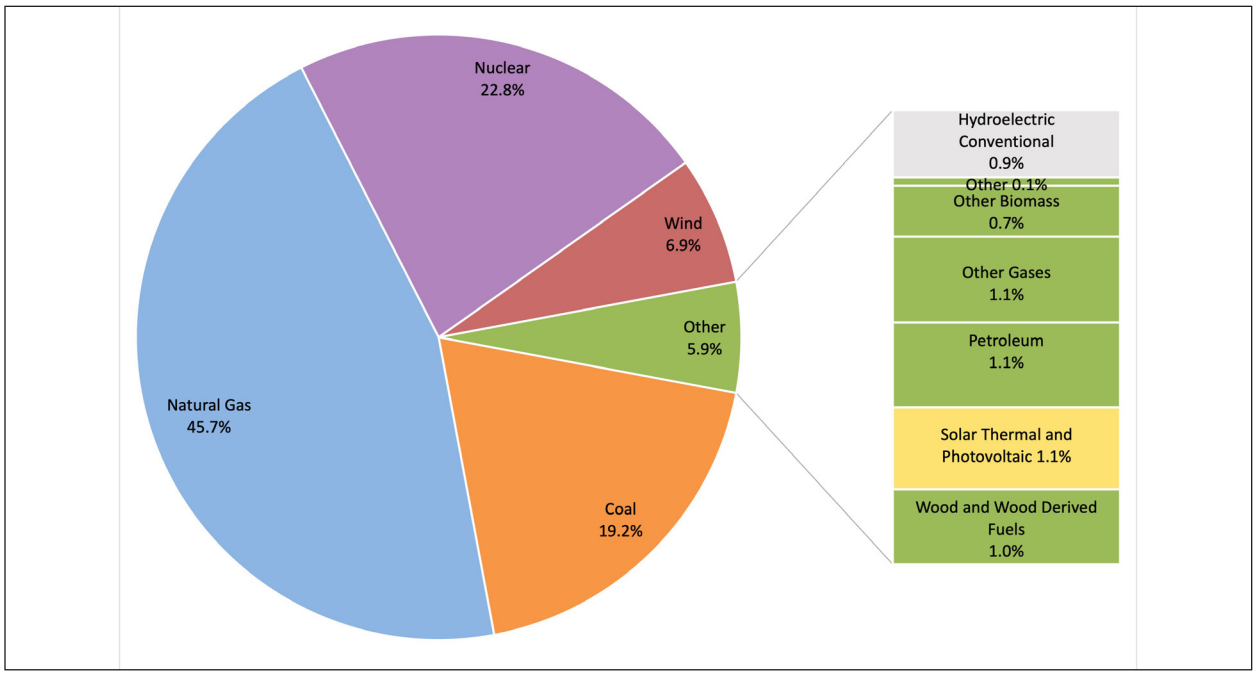
Source: Solar Energy Industries Association, Solar Spotlight: Michigan Q1 2025

Figure 2.5 – Michigan Annual Solar Installations



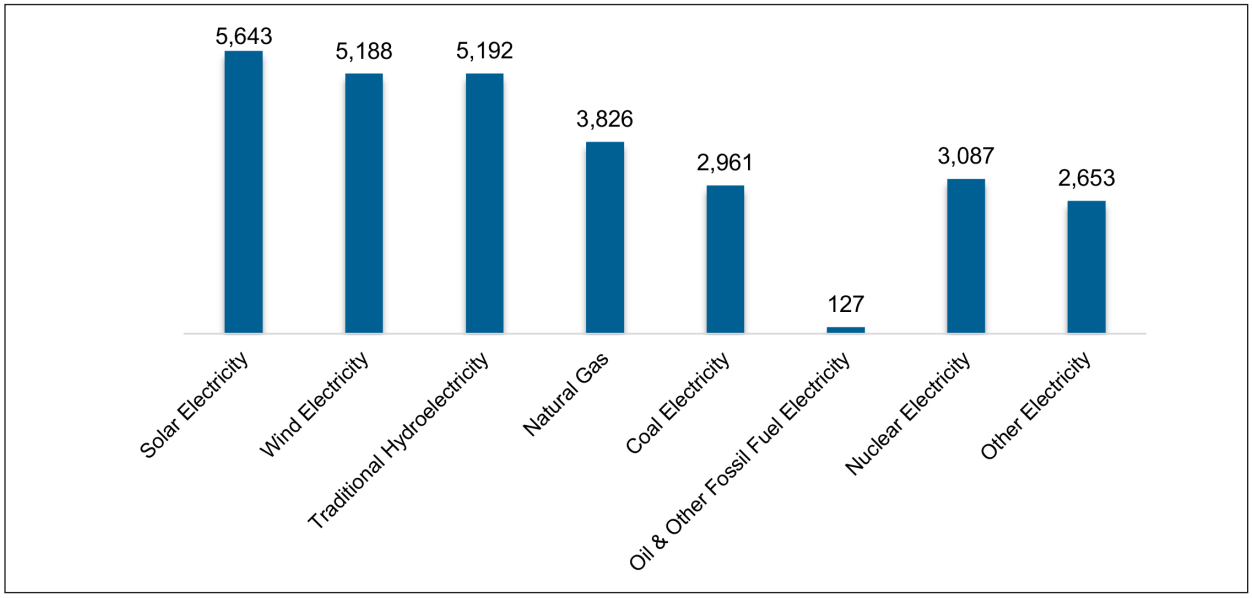
Source: Solar Energy Industries Association, Solar Spotlight: Michigan Q1 2025

Figure 2.6 – Electric Generation by Fuel Type for Michigan in 2023



Source: U.S. Energy Information Association (EIA): Michigan 2023

Figure 2.7 – Electric Generation Employment by Technology



Source: U.S. Energy and Employment Report 2024: Michigan

c. Economic Benefits of Utility-Scale Solar PV Energy

Utility-scale solar-powered electric generation facilities provide numerous economic benefits. Solar PV installations create job opportunities in the local area during both the short-term construction phase and the long-term operational phase. In addition to the workers directly involved in the construction and maintenance of the solar energy project, numerous other jobs are supported through indirect supply chain purchases and the higher spending that is induced by these workers. Solar PV projects strengthen the local tax base and help improve county services and local infrastructure, such as public roads.

Bessette et al. (2024) state that the potential economic benefits of a utility-scale solar project would include "increased property tax revenue, landowner payments, and increased employment" (Bessette et al., 2024, 7). They highlight the fact that the tax benefits are difficult for residents to understand – perhaps because they are not quantified clearly. They also mention both the direct and indirect (supply chain) economic impacts.

Numerous studies have quantified the economic benefits of United States solar PV projects and been published in peer-reviewed academic journals using the same methodology as this report. Some of these studies examine smaller-scale solar systems while some examine utility-scale solar energy. Croucher (2012) uses NREL's Jobs and Economic Development Impacts ("JEDI") modeling methodology to determine which states would receive the greatest economic impact from installing one hundred 2.5 kW residential systems. According to the report, Pennsylvania ranked first, supporting 28.98 jobs during installation and 0.20 jobs during operations. Illinois ranked second, supporting 27.65 jobs during construction and 0.18 jobs during operations.

More recently, Michaud et al. (2020) performed economic impact analyses of utility-scale solar energy projects in the State of Ohio. They detail three scenarios: low (2.5 GW), moderate (5 GW), and high (7.5 GW). Using the JEDI model, they conclude that between 18,039 and 54,113 jobs would be supported during construction and between 207 and 618 jobs would be supported annually during operations. In addition, these projects would generate between $22.5 million and $67.5 million annually in tax revenues.

Loomis et al. (2016) estimates the economic impact for the State of Illinois if it were to reach its maximum potential for solar PV. This study details three different scenarios — new solar project installations of either 2,292 MW, 2,714 MW or 11,265 MW. The study assumes that 60% of the capacity is utility-scale solar, 30% of the capacity is commercial, and 10% of the capacity is residential. It concludes that employment impacts would vary from 26,753 to 131,779 job years during construction and from 1,223 to 6,010 job years during operations.

The Michigan Conservative Energy Forum (2018) commissioned a study by The Hill Group in 2018 to examine the economic impacts of different renewable portfolio standards for the State of Michigan. They found that "the 12.5 percent by 2019 scenario indicates that the selected activities as a whole could have a potential gross impact of nearly $3.8 billion on Michigan, including more than 20,100 job-years supported and nearly $1.4 billion in employee compensation."

Finally, Jenniches (2018) performed a literature review assessing the regional economic impacts of renewable energy sources. After reviewing all of the different techniques for analyzing the economic impacts, he concludes "for assessment of current renewable energy developments, beyond employment in larger regions, IO [Input-Output] tables are the most suitable approach" (Jenniches, 2018, 48). Input-Output analysis is the basis for the methodology used in the economic impact analysis of this report.

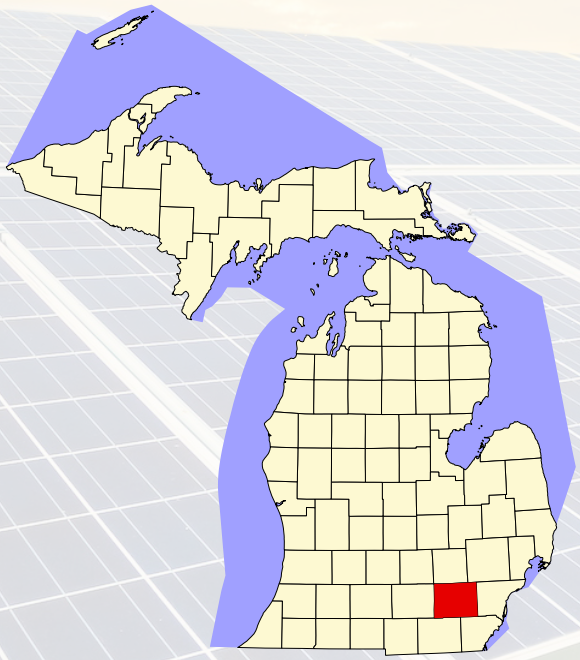
a. Washtenaw Solar

Invenergy is developing the Washtenaw Solar Project in Washtenaw County, Michigan. The Project consists of an estimated 150-megawatt alternating current (MWac) utility-scale solar powered-electric generation facility that will utilize photovoltaic (PV) panels installed on a single-axis tracking system. The total Project represents an investment in excess of $237 million.

b. Washtenaw County Economic and Demographic Statistics

Washtenaw County is located in the southern part of Michigan (see Figure 3.1). It has a total area of 722 square miles, and the U.S. Census estimates that the population was 373,875 with 163,177 housing units in 2024. The county has a population density of 529 (persons per square mile) compared to 174 for the State of Michigan (2024). Median household income in the county was $87,156 in 2023 (U.S. Census Bureau, 2024).

Figure 3.1 – Location of Washtenaw County, Michigan



Source: Wikipedia, 2024. Data from nationalatlas.gov

Table 3.1 – Employment by Industry in Washtenaw County

Industry	Number	Percent
Administrative Government	73,407	25.8%
Professional, Scientific, and Technical Services	36,060	12.7%
Health Care and Social Assistance	31,518	11.1%
Accommodation and Food Services	17,781	6.2%
Retail Trade	17,443	6.1%
Other Services (except Public Administration)	13,088	4.6%
Manufacturing	12,932	4.5%
Real Estate and Rental and Leasing	12,405	4.4%
Administrative and Support and Waste Management and Remediation Services	11,458	4.0%
Finance and Insurance	9,391	3.3%
Construction	8,892	3.1%
Transportation and Warehousing	8,606	3.0%
Information	7,531	2.6%
Wholesale Trade	7,419	2.6%
Arts, Entertainment, and Recreation	6,039	2.1%
Educational Services	5,701	2.0%
Management of Companies and Enterprises	2,116	0.7%
Agriculture, Forestry, Fishing and Hunting	1,456	0.5%
Government Enterprises	896	0.3%
Utilities	393	0.1%
Mining, Quarrying, and Oil and Gas Extraction	319	0.1%

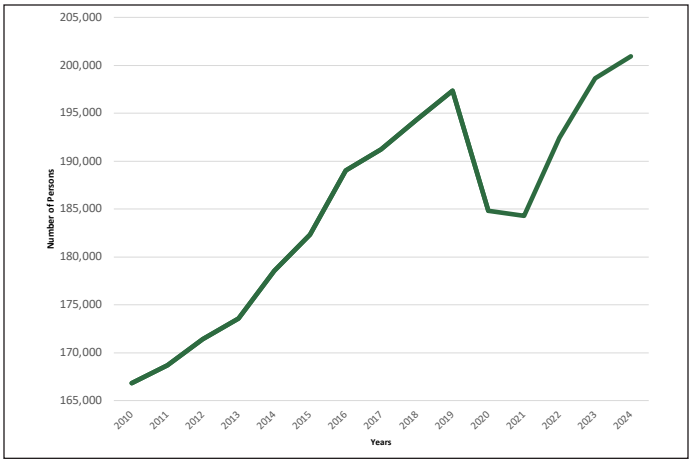
Source: Impact Analysis for Planning (IMPLAN), County Employment by Industry, 2023

As shown in Table 3.1, the largest industries in the county are "Administrative Government" followed by "Professional, Scientific, and Technical Services," "Health Care and Social Assistance," and "Accommodation and Food Services." These data for Table 3.1 come from IMPLAN covering the year 2023 (the latest year available).

Table 3.1 provides the most recent snapshot of total employment but does not examine the historical trends within the county.

Figure 3.2 shows the number of employed persons in Washtenaw County from 2010 to 2024. The total number of employed persons was at its lowest at 166,815 in 2010 and its highest at 200,958 in 2024 (FRED, 2025).

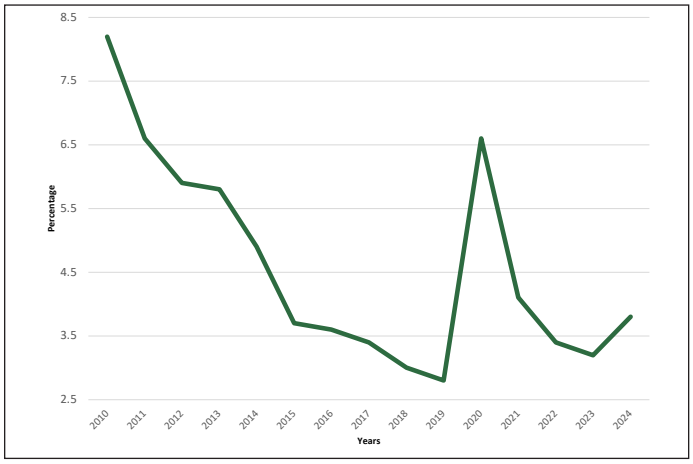
Figure 3.2 – Total Employed Persons in Washtenaw County from 2010 to 2024



Source: Federal Reserve Bank of St. Louis Economic Data, U.S. Census Bureau, Employed Persons, 2010-2024

The unemployment rate signifies the percentage of the labor force without employment in the county. Figure 3.3 shows the unemployment rates from 2010 to 2024. Unemployment in Washtenaw County was at its highest at 8.2% in 2010 and its lowest at 2.8% in 2019 (FRED, 2025). The unemployment rate spiked to 6.6% in 2020 but normalized to 3.2% in 2023.

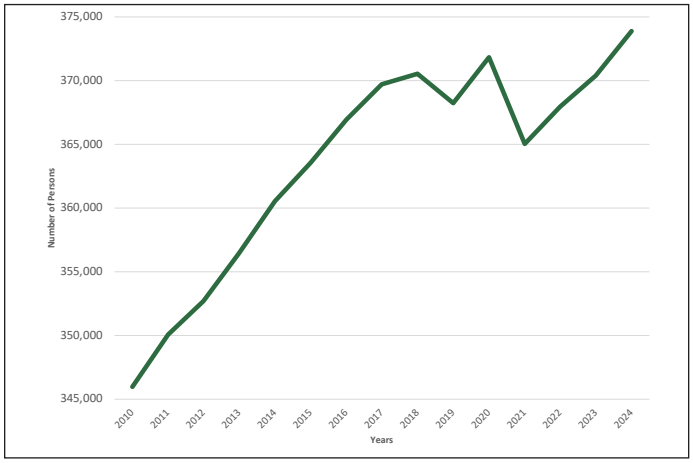
Figure 3.3 – Unemployment Rate in Washtenaw County from 2010 to 2024



Source: Federal Reserve Bank of St. Louis Economic Data, U.S. Census Bureau, Unemployment Rates, 2010-2024

The overall population in the county has trended upward, as shown in Figure 3.4. Washtenaw County's population was 345,980 in 2010 and 373,875 in 2024, a gain of 27,895 people (FRED, 2025). The average annual population increase over this time period was 1,993 people.

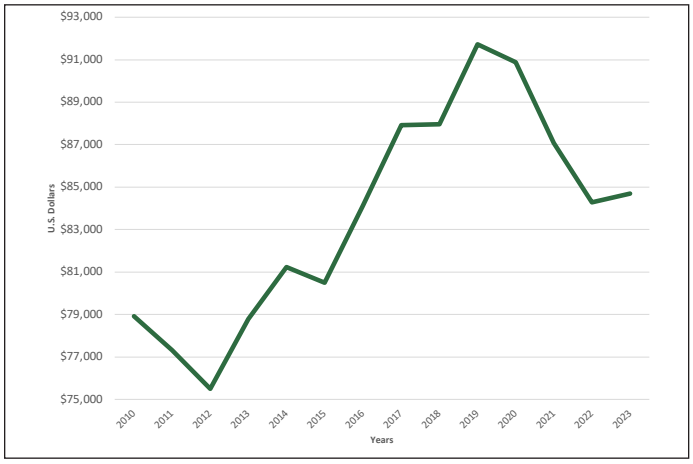
Figure 3.4 – Population in Washtenaw County from 2010 to 2024



Source: Federal Reserve Bank of St. Louis Economic Data, U.S. Census Bureau, Population Estimates, 2010-2024

Household income has trended upward in the county. Figure 3.5 shows the real median household income in Washtenaw County from 2010 to 2023. Using the national Consumer Price Index (CPI), the nominal median household income for each year was adjusted to 2023 dollars. Household income was at its lowest at $75,507 in 2012 and its highest at $91,735 in 2019 (FRED, 2024).

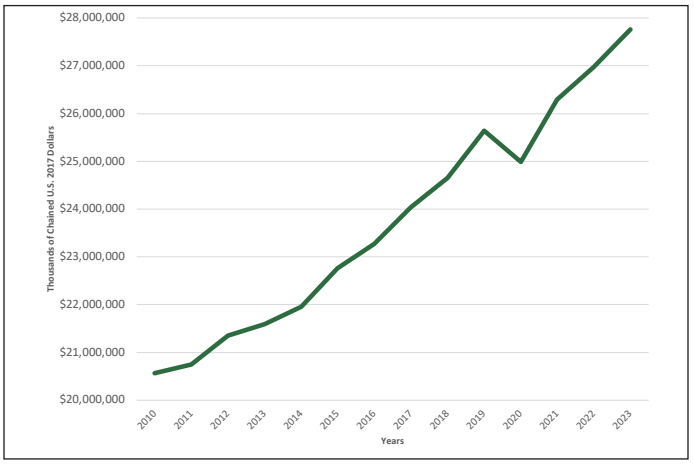
Figure 3.5 – Real Median Household Income in Washtenaw County from 2010 to 2023



Source: Federal Reserve Bank of St. Louis Economic Data, U.S. Census Bureau, Estimate of Median Household Income, 2010-2023

Real Gross Domestic Product (GDP) is a measure of the value of goods and services produced in an area and adjusted for inflation over time. The Real GDP for Washtenaw County has increased since hitting a low in 2010, as shown in Figure 3.6 (FRED, 2024).

Figure 3.6 – Real Gross Domestic Product (GDP) in Washtenaw County from 2010 to 2023



Source: Federal Reserve Bank of St. Louis Economic Data, U.S. Census Bureau, Real Gross Domestic Product, 2010-2023

IV. Economic Impact Methodology

The economic analysis of the Project was created using IMPLAN (IMpact analysis for PLANning). IMPLAN software and parameters are based on government data collected at federal, state, and local levels. IMPLAN is a leading provider of economic development software that is widely used by economists and economic development professionals. More information about IMPLAN can be found at implan.com.

IMPLAN is an input-output model that measures the spending patterns and location-specific economic structures that reflect expenditures supporting varying levels of employment, income, and output. In other words, IMPLAN demonstrates how one industry's output can be used as an input for another. For example, when a PV system is installed, there are both soft costs — consisting of permitting, installation, and customer acquisition costs — and hardware costs, of which the PV module is the largest component. The purchase of a module not only increases demand for manufactured components and raw materials, but it also supports the labor required to build and install the module. When a module is purchased from a manufacturing facility, the manufacturer uses some of that money to pay its employees. Then, the employees spend that money on goods and services within their community. Likewise, when a developer pays workers to install the systems, those workers spend money in the local economy which boosts economic activity and supports employment in other sectors. The goal of an economic impact analysis is to quantify all reverberations throughout the county and state economies.

IMPLAN modeling uses construction cost data, operations cost data, and data relating to the percentage of goods and services acquired in the county and state to calculate the jobs, earnings, and economic output associated with this information.

The results are split into the construction period and the annual operations period of the solar project. Within each period, impacts are further divided into direct, indirect, and induced impacts.

Direct impacts during the construction period refer to the changes that occur in the on-site construction industries in which the direct final demand (i.e., spending on construction labor and services) change is made. On-site construction-related services include installation labor, engineering, design, and other professional services. **Direct impacts during operating years** refer to the final demand changes in on-site spending required for solar operations and maintenance workers, their managers, and administrative/clerical staff.

The initial spending for a project's construction and operation will create a second layer of impacts, referred to as "supply chain impacts" or "indirect impacts." **Indirect impacts during the construction** period consist of changes in inter-industry purchases resulting from the direct final demand changes. These impacts stem from construction spending on solar farm materials (PV modules, inverters, tracking systems, cabling, foundations, etc.) as well as purchases of offsite services like materials transportation, road repair, accounting/payroll, legal guidance, etc. **Indirect impacts during the operations period** also consist of changes in inter-industry purchases resulting from the direct final demand changes, but these impacts result from spending on equipment/materials pertaining to a solar farm's annual operations and maintenance (vehicles, gasoline, tools, etc.) and other services (i.e. repair work, vegetation management, wildlife monitoring, etc.). Property tax payments during annual operations create indirect impacts in the county and state that show up in the operations portion of the results.

These payments do not support the day-to-day operations and maintenance of the solar farm; they are more of a latent effect resulting from the solar farm's presence.

Induced impacts during construction refer to the changes that occur in household spending as household income increases or decreases as a result of the direct and indirect effects of final demand changes during construction. Local employees (working directly or indirectly on the project), who receive their paychecks and then spend money in the community, are supporting additional local jobs and economic activity. For example, in-county and in-state construction workers constructing the solar farm will spend a portion of their wages in the local economy at restaurants, grocery stores, retail establishments, hospitals, medical offices, etc. **Induced impacts during operating years** refer to the changes that occur in household spending as household income increases or decreases as a result of the direct and indirect effects from final demand changes during annual operations and maintenance work. For example, when on-site solar technicians and contracted landscapers residing in-county and in-state are paid for their work on the solar farm, they can then spend their wages at local establishments which spurs more local economic activity.

To estimate the economic impacts of the Project, SER uses two separate Multi-Regional Input-Output (MRIO) IMPLAN models with 2023 economic data, the most recent data year available at the time of analysis. The first IMPLAN model calculates construction period impacts using the project specific county economic data in conjunction with aggregated economic data that is combined from every other county in the state. Costs are then assigned to either region according to client-provided expected spending patterns, SER industry knowledge honed from over 400 previous analyses, and IMPLAN data related to the availability of relevant goods and services within the county and state economies. When results for the two regions are combined, they create the state's total construction period impacts. This method allows for more precise assignment of construction spending within the project's county and/or state.

The second model calculates impacts stemming from the annual operations and maintenance of the solar project. Like the construction period model, the operations period model also utilizes economic data from both the project's county and a region comprised of every other county in the state combined. Results from these two regions create the state's total annual operations period economic impacts.

The majority of project employees needed during the construction phase are construction workers, but there are other occupations involved as well. Likewise, there are more occupations than solar technicians involved during the project's operations phase. A sample of those occupations, the education/training they require, and wage percentiles are contained in Table 7.1 in the Appendix. A larger description of those occupations, including their work environment and future growth potential, is located in Table 7.2 in the Appendix.

SER analyzes the gross number of jobs a new solar project development supports but not the potential loss of jobs due to declines in other forms of electricity generation. Impacts are determined by the robustness and applicability of the county and state economies, the client's intended spending in the project's county and state, and the labor levels within the county and state.

V. Economic Impact Results

The economic impact results[4] were derived from detailed project cost estimates supplied by Invenergy. In addition, Invenergy and SER estimated the percentages of project materials and labor that will be coming from within Washtenaw County and the State of Michigan.

The results from these models are shown in Tables 5.1 to 5.3. Table 5.1 lists the Project's total employment impacts for Washtenaw County and the State of Michigan. Table 5.2 shows the total earnings impacts, and Table 5.3 contains the total output impacts. The results are divided into one-time construction impacts and ongoing annually recurring operations impacts that are expected to last the Project's lifetime. Project Development and On-site Labor Impacts correspond to direct impacts as defined in the methodology section. Supply Chain Impacts are the indirect impacts during construction, and Local Revenue and Supply Chain Impacts are indirect impacts during operations.

Table 5.1 – Total Employment Impacts from the Washtenaw Solar Project

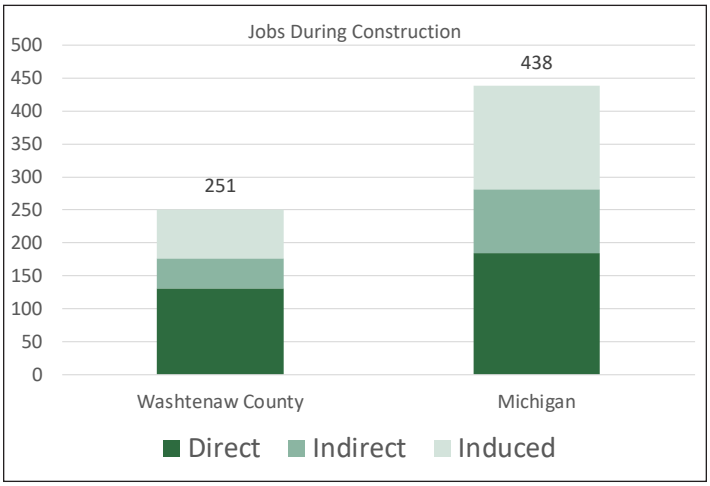
	Washtenaw County Jobs	State of Michigan Jobs
Construction		
Project Development and On-site Labor Impacts	131	184
Supply Chain Impacts	46	97
Induced Impacts	74	157
Local Jobs during Construction	251	438
Operations (Annual/Ongoing)		
On-site Direct Impacts	1.8	3.5
Local Revenue and Supply Chain Impacts	3.9	4.8
Induced Impacts	7.4	9.9
Local Long-Term Jobs	13.1	18.2

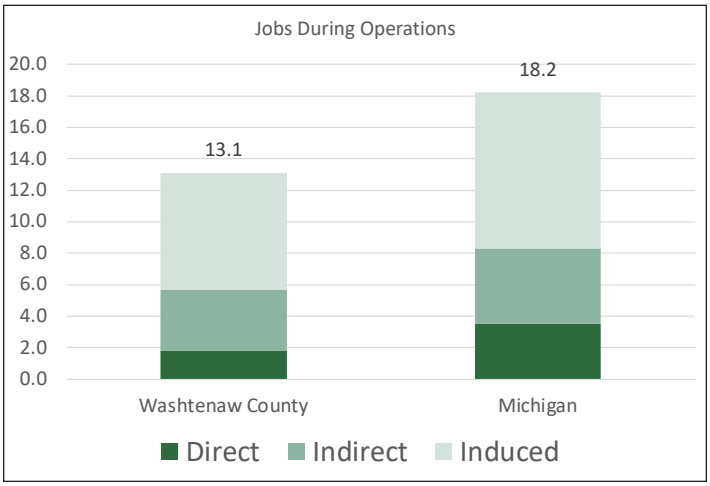
[4] Results are not intended to be a precise forecast; they are an estimate of potential activity resulting from a specific set of intended costs and assumed spending in-county and in-state.

The results from the IMPLAN model show significant employment impacts from the Washtenaw Solar Project. Direct jobs created during the construction phase typically last anywhere from 12 to 18 months depending on the size of the project; however, the direct job numbers present in Table 5.1 from the IMPLAN model are based on a full time equivalent (FTE) basis for a year. In other words, 1 job = 1 FTE = 2,080 hours worked in a year. A part time or temporary job would constitute only a fraction of a job according to the model. For example, the IMPLAN model results show 131 new direct jobs during construction in Washtenaw County, though the construction of the project could involve closer to 262 workers working half-time for a year. Thus, due to the short-term nature of construction projects, IMPLAN often significantly understates the actual number of people, i.e. "boots on the ground," hired to work on the project. Conversely, if the construction period lasts for two years, the job numbers from Table 5.1 would mean that the actual number of workers at any given time would be half of the reported number. It is important to keep this fact in mind when viewing or reporting the numbers.

As shown in Table 5.1, new local jobs created or retained during construction total 251 for Washtenaw County and 438 for the State of Michigan. New local long-term jobs created from the Washtenaw Solar Project total 13.1 for Washtenaw County and 18.2 for the State of Michigan.

Figure 5.1 – Total Employment Impacts from the Washtenaw Solar Project





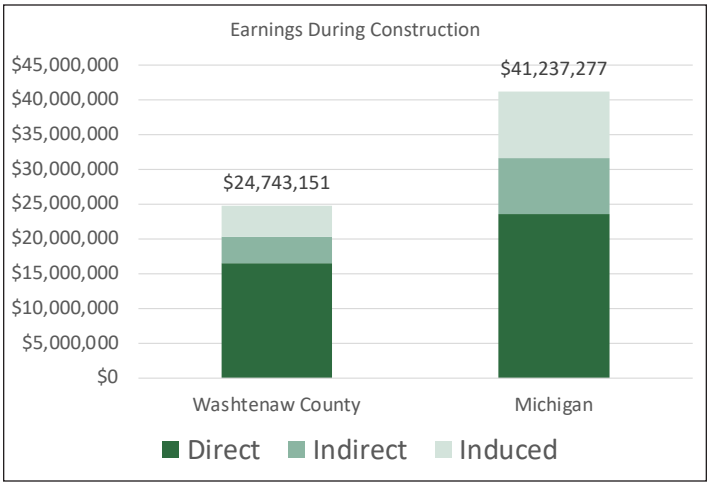
Direct jobs created during the operational phase last the life of the project, typically 20-30 years. Direct construction jobs and operations and maintenance jobs both require highly skilled workers in the fields of construction, management, and engineering. These well-paid professionals can boost economic development in communities where new employment opportunities are welcome due to economic downturns. For a list of occupations expected to be employed, their wages, benefits, total compensation, and hours worked, please see Tables 7.3 to 7.5 in the Appendix.

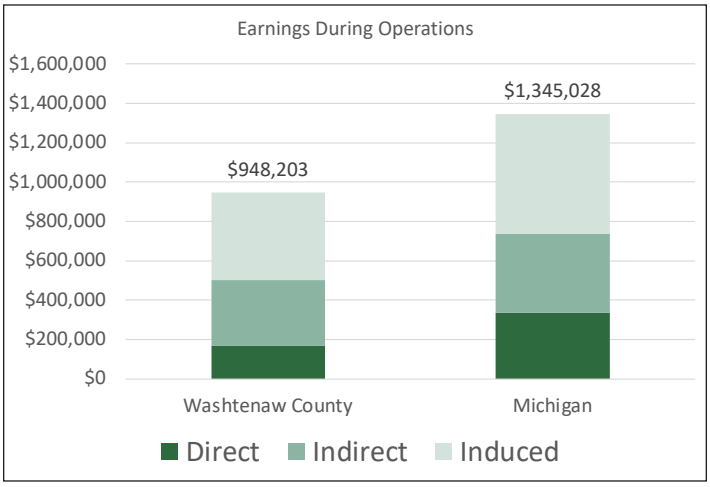
Accordingly, it is important to look at both the number of jobs and the earnings they produce. Table 5.2 shows the earnings impacts from the Washtenaw Solar Project, which are categorized by construction impacts and annual operations impacts. The new local earnings during construction total over $24.7 million for Washtenaw County and over $41.2 million for the State of Michigan. The new local long-term earnings total over $948 thousand for Washtenaw County and over $1.3 million for the State of Michigan.

Table 5.2 – Total Earnings Impacts from the Washtenaw Solar Project

	Washtenaw County	State of Michigan
Construction		
Project Development and On-site Labor Earnings Impacts	$16,481,424	$23,638,719
Supply Chain Impacts	$3,798,785	$8,003,204
Induced Impacts	$4,462,942	$9,595,354
Local Earnings during Construction	$24,743,151	$41,237,277
Operations (Annual/Ongoing)		
On-site Labor Earnings Impacts	$167,243	$334,487
Local Revenue and Supply Chain Impacts	$335,790	$404,929
Induced Impacts	$445,170	$605,612
Local Long-Term Earnings	$948,203	$1,345,028

Figure 5.2 – Total Earnings Impacts from the Washtenaw Solar Project





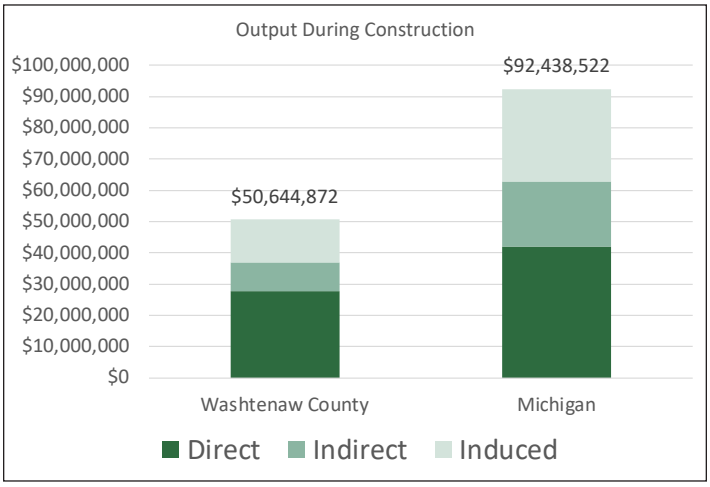
Output is akin to Gross Domestic Product (GDP) and refers to economic activity or the value of production in the state or county economy. Economic output includes the earnings reported in Table 5.2 but also measures other factors such as landowner payments, property taxes, and other economic activity that is neither earnings nor benefits from employment.

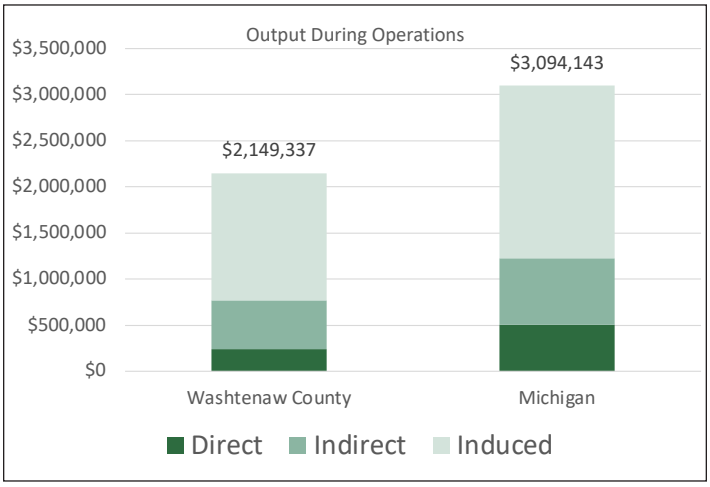
According to Table 5.3, the new local output during construction totals over $50.6 million for Washtenaw County and over $92.4 million for the State of Michigan. The new local long-term output totals over $2.1 million for Washtenaw County and over $3.0 million for the State of Michigan.

Table 5.3 – Total Output Impacts from the Washtenaw Solar Project

	Washtenaw County	State of Michigan
Construction		
Project Development and On-site Labor Impacts on Output	$27,649,605	$42,089,045
Supply Chain Impacts	$9,172,492	$20,845,946
Induced Impacts	$13,822,775	$29,503,531
Local Output during Construction	$50,644,872	$92,438,522
Operations (Annual/Ongoing)		
On-site Labor Impacts on Output	$239,790	$505,059
Local Revenue and Supply Chain Impacts	$531,716	$720,911
Induced Impacts	$1,377,831	$1,868,173
Local Long-Term Output	$2,149,337	$3,094,143

Figure 5.3 – Total Output Impacts from the Washtenaw Solar Project





VI. Tax Benefits

Solar projects increase the property tax base of a county, creating a new revenue source for education and other local government services, such as fire protection, parks, health, and safety. Estimates of the taxable value of each type of property were obtained from the client. In Michigan, qualified solar facilities, excluding the transmission line, are exempt from property taxes for 20 years after applying for exemption. Projects that receive this exemption will pay a solar energy facilities tax of $7,000 per megawatt of nameplate capacity in most cases during operations. After 20 years, ordinary property taxes resume.

Tables 6.1 to 6.4 detail the tax implications of the Washtenaw Solar Project. There are several important assumptions built into the analysis, as follows:

- The analysis assumes that the Project qualifies for the Solar Energy Facilities Tax of $7,000/MW for the first 20 years of operations and is otherwise exempt from industrial personal property tax.[5]
- It assumes that the nameplate capacity for the Project is 150 MW.
- It assumes that the Solar Energy Facilities Tax is allocated to the taxing jurisdictions according to their relative millage rates.
- The analysis only includes taxes during operations for the Project starting in 2028 and lasting for 30 years. The analysis does not include taxes paid while construction is in progress.
- The analysis assumes that after 20 years of eligibility, ordinary industrial personal property taxes will be paid and that the total taxable industrial personal property will be $215 million.
- The tables assume that once the Project is eligible for ordinary property taxes, it has depreciated to the minimum depreciable value of 12% based on the 2022 Solar Energy System Report Form 5762. It will be assessed at the 50% assessment ratio.
- All tax (millage) rates are assumed to stay constant at their 2025 (2024 tax year) rates. Assumed millage rates are 6 for the State Education Tax, 7.5495 for Washtenaw County, 18 for Clinton Community Schools Operating, 5.75 for Clinton Community Schools Bond, 18 for Saline Area School District Operating, 7.5 for Saline Area School District Debt, 7.2922 for Lenawee Intermediate School District, 5.4889 for Washtenaw Intermediate School District, 3.3548 for Washtenaw Community College, 0.9105 for Saline Township, 0.9968 for Saline Township Roads, 0.3436 for Saline Sinking Fund, 0.491 for Saline Recreation, 1 for Saline Fire, and 1.1392 for Saline District Library.

[5] https://www.legislature.mi.gov/documents/2023-2024/publicact/pdf/2023-PA-0108.pdf

- The Project is assumed to be exempted from school operating fund taxes and the state education fund taxes, both under the Solar Energy Facilities Tax and Industrial Personal Property tax.
- The Project is assumed to pay Utility Personal Property taxes on the transmission line ($560 thousand of assessed value) that is not eligible for the Solar Energy Facilities Tax exemption.
- The Project is assumed to pay a 1% administrative fee on all taxes paid.
- The names of the taxing bodies used in this section come from the county and state tax websites.
- The comprehensiveness and accuracy of the analysis below is dependent upon the assumptions listed above and used to calculate the property tax results. The analysis is to serve as a projection of property tax benefits to the local community and is not a guarantee of property tax revenue.
- If the inputs received from Invenergy, the laws surrounding renewable energy taxation in Michigan, or the millage rates in Washtenaw County change in a material way after the completion of this report, this analysis may no longer accurately reflect the property taxes to be paid by the Washtenaw Solar Project.
- No comprehensive tax payment was calculated, and these calculations are only to be used to illustrate the economic impact of the Project.

Figure 6.1 – Percentages of Property Taxes Paid to Taxing Jurisdictions

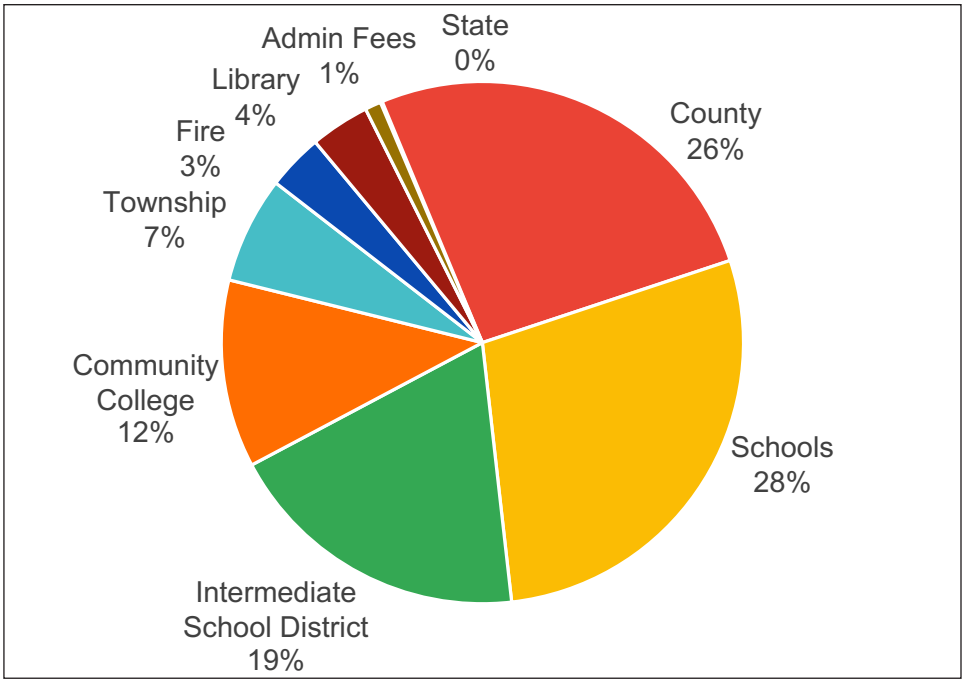


Table 6.1 – Total Property Taxes Paid by the Washtenaw Solar Project

Year	Total Paid
2028	$1,074,796
2029	$1,074,349
2030	$1,073,903
2031	$1,073,307
2032	$1,072,711
2033	$1,072,116
2034	$1,071,520
2035	$1,070,924
2036	$1,070,477
2037	$1,070,031
2038	$1,069,584
2039	$1,069,137
2040	$1,068,690
2041	$1,068,244
2042	$1,067,946
…	$1,067,946
2047	$1,067,946
2048	$360,512
…	$360,512
2057	$360,512
TOTAL	$25,012,585
AVG ANNUAL	$833,753

As shown in Table 6.1, a conservative estimate of the total property taxes paid by the Project starts out at over $1.0 million and declines due to depreciation until it reaches the maximum depreciation in year 15. In year 20, ordinary industrial personal property taxes resume. The expected total property taxes paid over the 30-year lifetime of the Project are over $25.0 million, and the average annual property taxes paid will be over $833 thousand.

Table 6.2 shows an estimate of the likely taxes paid to the following taxing bodies: State Education Tax, Washtenaw County, Saline Township, Saline Township Roads, Saline Sinking Fund, and Saline Recreation. According to Table 6.2, the total amounts paid over 30 years are over $30.6 thousand for the State Education Tax, over $6.5 million for Washtenaw County, over $789 thousand for Saline Township, over $864 thousand for Saline Township Roads, over $277 thousand for Saline Sinking Fund, and over $396 thousand for Saline Recreation over the Project's lifetime.

Table 6.2 – Tax Benefits from the Washtenaw Solar Project for the County & Other Taxing Bodies

Year	State Education Tax	Washtenaw County	Saline Township	Saline Township Roads	Saline Sinking Fund	Saline Recreation
2028	$1,613	$278,635	$33,604	$36,790	$11,914	$17,025
2029	$1,562	$278,571	$33,597	$36,781	$11,911	$17,021
2030	$1,512	$278,508	$33,589	$36,773	$11,908	$17,017
2031	$1,445	$278,423	$33,579	$36,762	$11,905	$17,012
2032	$1,378	$278,339	$33,569	$36,751	$11,901	$17,007
2033	$1,310	$278,254	$33,559	$36,739	$11,898	$17,001
2034	$1,243	$278,170	$33,548	$36,728	$11,894	$16,996
2035	$1,176	$278,085	$33,538	$36,717	$11,890	$16,991
2036	$1,126	$278,022	$33,531	$36,709	$11,888	$16,987
2037	$1,075	$277,958	$33,523	$36,700	$11,885	$16,983
2038	$1,025	$277,895	$33,515	$36,692	$11,882	$16,980
2039	$974	$277,832	$33,508	$36,684	$11,880	$16,976
2040	$924	$277,768	$33,500	$36,675	$11,877	$16,972
2041	$874	$277,705	$33,492	$36,667	$11,874	$16,968
2042	$840	$277,662	$33,487	$36,661	$11,872	$16,965
…	$840	$277,662	$33,487	$36,661	$11,872	$16,965
2047	$840	$277,662	$33,487	$36,661	$11,872	$16,965
2048	$840	$98,564	$11,887	$13,014	$3,962	$5,662
…	$840	$98,564	$11,887	$13,014	$3,962	$5,662
2057	$840	$98,564	$11,887	$13,014	$3,962	$5,662
TOTAL	$30,677	$6,545,784	$789,448	$864,274	$277,360	$396,345
AVG ANNUAL	$1,023	$218,193	$26,315	$28,809	$9,245	$13,211

Table 6.3 shows an estimate of the likely taxes paid to the relevant taxing bodies. According to Table 6.3, the total amounts paid over 30 years are over $329 thousand for Lenawee Intermediate School District, over $4.4 million for the Washtenaw Intermediate School District, over $2.9 million for Washtenaw Community College, over $867 thousand for the Saline Fire, over $919 thousand for Saline District Library, and over $247 thousand for Admin Fees over the Project's lifetime.

Table 6.3 – Tax Benefits from the Washtenaw Solar Project for Other Taxing Bodies

Year	Lenawee Intermediate School District	Washtenaw Intermediate School District	Washtenaw Community College	Saline Fire	Saline District Library	Admin Fees
2028	$16,292	$190,320	$123,818	$36,908	$39,500	$10,642
2029	$16,288	$190,277	$123,790	$36,899	$39,491	$10,637
2030	$16,284	$190,233	$123,762	$36,891	$39,482	$10,633
2031	$16,279	$190,176	$123,724	$36,880	$39,470	$10,627
2032	$16,274	$190,118	$123,687	$36,869	$39,458	$10,621
2033	$16,269	$190,060	$123,649	$36,857	$39,446	$10,615
2034	$16,264	$190,002	$123,611	$36,846	$39,434	$10,609
2035	$16,259	$189,945	$123,574	$36,835	$39,422	$10,603
2036	$16,256	$189,901	$123,546	$36,827	$39,413	$10,599
2037	$16,252	$189,858	$123,517	$36,818	$39,404	$10,594
2038	$16,248	$189,815	$123,489	$36,810	$39,395	$10,590
2039	$16,245	$189,771	$123,461	$36,801	$39,386	$10,586
2040	$16,241	$189,728	$123,433	$36,793	$39,377	$10,581
2041	$16,237	$189,685	$123,405	$36,785	$39,368	$10,577
2042	$16,235	$189,656	$123,386	$36,779	$39,362	$10,574
…	$16,235	$189,656	$123,386	$36,779	$39,362	$10,574
2047	$16,235	$189,656	$123,386	$36,779	$39,362	$10,574
2048	$407	$63,292	$43,799	$13,056	$13,136	$3,569
…	$407	$63,292	$43,799	$13,056	$13,136	$3,569
2057	$407	$63,292	$43,799	$13,056	$13,136	$3,569
TOTAL	$329,168	$4,430,745	$2,908,775	$867,049	$919,584	$247,649
AVG ANNUAL	$10,972	$147,692	$96,959	$28,902	$30,653	$8,255

The largest taxing jurisdictions for property taxes are local school districts. However, the tax implications for school districts are more complicated than for other taxing bodies. School districts receive state aid based on the assessed value of the taxable property within their district. As assessed value increases, the state aid to the school district is decreased.

Although the exact amount of the reduction in state aid to the school districts is uncertain, local project tax revenue is superior to relying on state aid for the following reasons: (1) the solar project can't relocate – it is a permanent structure that will be within the school district's footprint for the life of the Project; (2) the school district can raise the tax rate and increase its revenues as needed; (3) the school district does not have to deal with the year-to-year uncertainty of state aid amounts; (4) the school district does not have to wait for months (or even into the next Fiscal Year) for payment; (5) the Project does not increase the overall cost of education in the way that a new residential development would.

Table 6.4 shows the direct property tax revenue coming from the Project to Clinton Community Schools and Saline Area School District. This tax revenue uses the assumptions outlined earlier to calculate the other tax revenue and assumes that 6.05% of the Project area is in the Clinton Community Schools and 93.95% of the Project area is in the Saline Area School District. Over the 30-year life of the Project, these school districts are expected to receive over $7.0 million in tax revenue.

Table 6.4 – Tax Benefits from the Washtenaw Solar Project for the School Districts

Year	Clinton Community Schools Operating	Clinton Community Schools Bond	Saline Area School District Operating	Saline Area School District Debt
2028	$293	$12,846	$4,546	$260,052
2029	$284	$12,843	$4,403	$259,993
2030	$275	$12,840	$4,261	$259,934
2031	$262	$12,836	$4,072	$259,855
2032	$250	$12,833	$3,883	$259,776
2033	$238	$12,829	$3,693	$259,697
2034	$226	$12,825	$3,504	$259,618
2035	$214	$12,821	$3,314	$259,539
2036	$204	$12,818	$3,172	$259,480
2037	$195	$12,815	$3,030	$259,421
2038	$186	$12,812	$2,888	$259,362
2039	$177	$12,809	$2,746	$259,302
2040	$168	$12,806	$2,604	$259,243
2041	$159	$12,803	$2,462	$259,184
2042	$153	$12,801	$2,367	$259,145
…	$153	$12,801	$2,367	$259,145
2047	$153	$12,801	$2,367	$259,145
2048	$153	$321	$2,367	$86,482
…	$153	$321	$2,367	$86,482
2057	$153	$321	$2,367	$86,482
TOTAL	$5,571	$259,553	$86,460	$6,054,143
AVG ANNUAL	$186	$8,652	$2,882	$201,805

Table 7.1 – Local and Statewide Compensation by Occupation

BLS Occupation Code	Job Type	Education/ Training Required	Michigan 10th Percentile of Wages	Michigan 90th Percentile of Wages	Michigan Mean Wages	Ann Arbor, MI 10th Percentile of Wages	Ann Arbor, MI 90th Percentile of Wages	Ann Arbor, MI Mean Wages	US Fringe Benefits Median	Total Compensation Local mean wages plus US Fringe
	Jobs during Construction									
47-2231	Solar Photovoltaic Installers	High school diploma or equivalent	$34,210	$171,070	$64,180	#N/A	#N/A	#N/A	$27,394	#N/A
47-3013	Helpers – Electricians	High school diploma or equivalent	$29,770	$46,600	$37,660	#N/A	#N/A	#N/A	$27,394	#N/A
47-2111	Electricians	High school diploma or equivalent	$36,560	$87,690	$62,850	$39,070	$90,300	$71,650	$27,394	$99,044
47-2061	Construction Laborers	No formal educational credential	$31,540	$59,970	$46,020	$35,860	$63,770	$49,430	$27,394	$76,824
47-2073	Operating Engineers and Other Construction Equipment Operators	High school diploma or equivalent	$40,360	$79,210	$60,340	$38,270	$82,270	$62,850	$27,394	$90,244
47-1011	First-Line Supervisors of Construction Trades	High school diploma or equivalent	$46,820	$104,510	$72,600	$50,510	$105,830	$75,330	$27,394	$102,724
13-1082	Project Management Specialists and Business Operations Specialists		$52,530	$134,910	$94,570	$55,310	$132,840	$92,350	$27,394	$119,744
49-9071	Maintenance and Repair Workers, General (Operations)	High school diploma or equivalent	$28,360	$61,860	$43,440	$29,510	$64,700	$45,980	$27,394	$73,374
13-1111	Management Analysts	Bachelor's degree	$49,700	$150,720	$102,780	$62,190	$127,740	$95,260	$27,394	$122,654
11-1021	General and Operations Managers	Bachelor's degree	$42,660	$213,620	$115,640	$46,680	#N/A	$129,420	$27,394	$156,814
17-2071	Electrical Engineers		$67,080	$132,940	$100,610	$62,720	$132,120	$100,430	$27,394	$127,824
41-3091	Sales Representatives of Services		$34,950	$133,450	$76,120	$37,610	$138,040	$85,250	$27,394	$112,644
53-7062	Laborers and Freight, Stock and Material Movers	No formal educational credential	$26,500	$51,380	$37,660	$29,800	$50,630	$37,600	$27,394	$64,994
43-3031	Bookkeeping, Accounting and Auditing	Some college, no degree	$30,450	$60,560	$45,090	$33,280	$62,230	$46,870	$27,394	$74,264
	Jobs during Operations									
51-8013	Power Plant Operators	High school diploma or equivalent	$71,150	$107,660	$91,810	$69,090	$103,890	$92,310	$27,394	$119,704
37-3011	Landscaping and Groundskeeping	No formal educational credential	$27,060	$45,890	$35,790	$26,160	$48,350	$37,060	$27,394	$64,454
51-1011	First-Line Supervisors of Production and Operating Workers	High school diploma or equivalent	$41,850	$101,210	$68,190	$43,850	$98,810	$68,650	$27,394	$96,044

Table 7.2 – Occupational Description and Future Outlook

Occupation Code	Occupation Title	Description	Work Environment	Current Employment	Job Growth, 2021-2031 (percent)
11-1021	General and Operations Managers	Plan, direct, or coordinate the operations of public or private sector organizations, overseeing multiple departments or locations. Duties and responsibilities include formulating policies, managing daily operations, and planning the use of materials and human resources, but are too diverse and general in nature to be classified in any one functional area of management or administration, such as personnel, purchasing, or administrative services. Usually manage through subordinate supervisors. Excludes First-Line Supervisors.	Top executives work in nearly every industry, for both small and large organizations. They often have irregular schedules, which may include working evenings and weekends. Travel is common, particularly for chief executives.	3,328,200	209,800 (7%)
13-1082	Project Management Specialists and Business Operations Specialists	Analyze and coordinate the schedule, timeline, procurement, staffing, and budget of a product or service on a per project basis. Lead and guide the work of technical staff. May serve as a point of contact for the client or customer. Excludes "Management Occupations" (11-0000), "Logisticians" (13-1081), "Meeting, Convention, and Event Planners" (13-1121), and "Production, Planning, and Expediting Clerks" (43-5061).	Project management specialists usually work in an office setting. Although project management specialists may collaborate on teams, some work independently. Project management specialists also may travel to their clients' places of business.	781,400	56,300 (7%)
13-1111	Management Analysts	Conduct organizational studies and evaluations, design systems and procedures, conduct work simplification and measurement studies, and prepare operations and procedures manuals to assist management in operating more efficiently and effectively. Includes program analysts and management consultants. Excludes "Computer Systems Analysts" (15-1211) and "Operations Research Analysts" (15-2031).	Management analysts may travel frequently to meet with clients. Some work more than 40 hours per week.	950,600	108,400 (11%)
17-2071	Electrical Engineers	Research, design, develop, test, or supervise the manufacturing and installation of electrical equipment, components, or systems for commercial, industrial, military, or scientific use. Excludes "Computer Hardware Engineers" (17-2061).	Electrical and electronics engineers work in industries including research and development, engineering services, manufacturing, telecommunications, and the federal government. Electrical and electronics engineers generally work indoors in offices. However, they may have to visit sites to observe a problem or a piece of complex equipment.	303,800	9,800 (3%)
37-3011	Landscaping and Groundskeeping	Landscape or maintain grounds of property using hand or power tools or equipment. Workers typically perform a variety of tasks, which may include any combination of the following: sod laying, mowing, trimming, planting, watering, fertilizing, digging, raking, sprinkler installation, and installation of mortarless segmental concrete masonry wall units. Excludes "Farmworkers and Laborers, Crop, Nursery, and Greenhouse" (45-2092).	Most grounds maintenance work is done outdoors in all weather conditions. Some work is seasonal, available mainly in the spring, summer, and fall. The work may be repetitive and physically demanding, requiring frequent bending, kneeling, lifting, or shoveling.	1,299,000	61,300 (5%)
41-3091	Sales Representatives of Services	Sell services to individuals or businesses. May describe options or resolve client problems. Excludes "Advertising Sales Agents" (41-3011), "Insurance Sales Agents" (41-3021), "Securities, Commodities, and Financial Services Sales Agents" (41-3031), "Travel Agents" (41-3041), "Sales Representatives, Wholesale and Manufacturing" (41-4010), and "Telemarketers" (41-9041).	Wholesale and manufacturing sales representatives work under pressure because their income and job security depend on the amount of merchandise they sell. Some sales representatives travel frequently.	1,597,600	63,300 (4%)
43-3031	Bookkeeping, Accounting and Auditing	Compute, classify, and record numerical data to keep financial records complete. Perform any combination of routine calculating, posting, and verifying duties to obtain primary financial data for use in maintaining accounting records. May also check the accuracy of figures, calculations, and postings pertaining to business transactions recorded by other workers. Excludes "Payroll and Timekeeping Clerks" (43-3051).	Most accountants and auditors work full time. Overtime hours are typical at certain periods of the year, such as for quarterly audits or during tax season.	1,449,800	81,800 (6%)
47-1011	First-Line Supervisors of Construction Trades	Directly supervise and coordinate activities of construction or extraction workers.	N/A	735,500	29,900 (4%)

Table 7.2 – Occupational Description and Future Outlook (Cont.)

47-2061	Construction Laborers	Perform tasks involving physical labor at construction sites. May operate hand and power tools of all types: air hammers, earth tampers, cement mixers, small mechanical hoists, surveying and measuring equipment, and a variety of other equipment and instruments. May clean and prepare sites, dig trenches, set braces to support the sides of excavations, erect scaffolding, and clean up rubble, debris, and other waste materials. May assist other craft workers. Construction laborers who primarily assist a particular craft worker are classified under "Helpers, Construction Trades" (47-3010). Excludes "Hazardous Materials Removal Workers" (47-4041).	Most construction laborers and helpers typically work full time and do physically demanding work. Some work at great heights or outdoors in all weather conditions. Construction laborers have one of the highest rates of injuries and illnesses of all occupations.	1,572,200	69,500 (4%)
47-2073	Operating Engineers and Other Construction Equipment Operators	Operate one or several types of power construction equipment, such as motor graders, bulldozers, scrapers, compressors, pumps, derricks, shovels, tractors, or front-end loaders to excavate, move, and grade earth, erect structures, or pour concrete or other hard surface pavement. May repair and maintain equipment in addition to other duties. Excludes "Extraction Workers" (47-5000) and "Crane and Tower Operators" (53-7021).	Construction equipment operators may work even in unpleasant weather. Most operators work full time, and some have irregular work schedules that include nights.	466,900	22,000 (5%)
47-2111	Electricians	Install, maintain, and repair electrical wiring, equipment, and fixtures. Ensure that work is in accordance with relevant codes. May install or service street lights, intercom systems, or electrical control systems. Excludes "Security and Fire Alarm Systems Installers" (49-2098).	Almost all electricians work full time. Work schedules may include evenings and weekends. Overtime is common.	711,200	50,200 (7%)
47-2231	Solar Photovoltaic Installers	Assemble, install, or maintain solar photovoltaic (PV) systems on roofs or other structures in compliance with site assessment and schematics. May include measuring, cutting, assembling, and bolting structural framing and solar modules. May perform minor electrical work such as current checks. Excludes solar PV electricians who are included in "Electricians" (47-2111) and solar thermal installers who are included in "Plumbers, Pipefitters, and Steamfitters" (47-2152).	Most solar panel installations are done outdoors, but PV installers sometimes work in attics and crawl spaces to connect panels to the electrical grid. Installers also must travel to jobsites.	17,100	4,600 (27%)
47-3013	Helpers – Electricians	Help electricians by performing duties requiring less skill. Duties include using, supplying, or holding materials or tools, and cleaning work area and equipment. Construction laborers who do not primarily assist electricians are classified under "Construction Laborers" (47-2061). Apprentice workers are classified with the appropriate skilled construction trade occupation (47-2011 through 47-2231).	Most construction laborers and helpers typically work full time and do physically demanding work. Some work at great heights or outdoors in all weather conditions. Construction laborers have one of the highest rates of injuries and illnesses of all occupations.	1,572,200	69,500 (4%)
49-9071	Maintenance and Repair Workers, General (Operations)	Perform work involving the skills of two or more maintenance or craft occupations to keep machines, mechanical equipment, or the structure of a building in repair. Duties may involve pipe fitting; HVAC maintenance; insulating; welding; machining; carpentry; repairing electrical or mechanical equipment; installing, aligning, and balancing new equipment; and repairing buildings, floors, or stairs. Excludes "Facilities Managers" (11-3013) and "Maintenance Workers, Machinery" (49-9043).	General maintenance and repair workers often carry out many different tasks in a single day. They could work at any number of indoor or outdoor locations. They may work inside a single building, such as a hotel or hospital, or be responsible for the maintenance of many buildings, such as those in an apartment complex or on a college campus.	1,539,100	76,300 (5%)
51-1011	First-Line Supervisors of Production and Operating Workers	Directly supervise and coordinate the activities of production and operating workers, such as inspectors, precision workers, machine setters and operators, assemblers, fabricators, and plant and system operators. Excludes team or work leaders.	N/A	646,800	12,200 (2%)
51-8013	Power Plant Operators	Control, operate, or maintain machinery to generate electric power. Includes auxiliary equipment operators. Excludes "Nuclear Power Reactor Operators" (51-8011).	Most power plant operators, distributors, and dispatchers work full time. Many work rotating 8- or 12-hour shifts.	43,700	(6,500) (-15%)
53-7062	Laborers and Freight, Stock and Material Movers	Manually move freight, stock, luggage, or other materials, or perform other general labor. Includes all manual laborers not elsewhere classified. Excludes "Construction Laborers" (47-2061) and "Helpers, Construction Trades" (47-3011 through 47-3019). Excludes "Material Moving Workers" (53-7011 through 53-7199) who use power equipment.	Most hand laborers and material movers work full time. Because materials are shipped around the clock, some workers, especially those in warehousing, work overnight shifts.	6,473,000	358,300 (6%)

Table 7.3 – Occupational Output from IMPLAN Construction Model, Direct Jobs, Employment Greater than 1.0

This table is directly modeled for this project.

Occ Code	Occupation	Wage and Salary Employment	Wage and Salary Income	Supplements to Wages and Salaries	Employee Compensation	Hours Worked
47-2000	Construction Trades Workers	38.70	$3,298,210.38	$568,051.48	$3,866,261.86	74,842.06
49-9000	Other Installation, Maintenance, and Repair Occupations	30.84	$3,092,704.56	$532,657.17	$3,625,361.72	65,218.58
47-1000	Supervisors of Construction and Extraction Workers	10.26	$1,273,388.82	$219,316.03	$1,492,704.85	22,208.84
49-1000	Supervisors of Installation, Maintenance, and Repair Workers	7.42	$999,067.26	$172,069.57	$1,171,136.82	16,128.04
13-1000	Business Operations Specialists	6.32	$811,153.13	$139,705.08	$950,858.21	12,684.62
11-9000	Other Management Occupations	4.94	$882,452.06	$151,984.91	$1,034,436.97	10,625.82
11-1000	Top Executives	3.66	$817,953.46	$140,876.29	$958,829.75	8,050.64
43-9000	Other Office and Administrative Support Workers	2.62	$164,432.30	$28,320.21	$192,752.51	4,239.28
43-3000	Financial Clerks	2.20	$171,771.18	$29,584.18	$201,355.36	3,947.94
49-2000	Electrical and Electronic Equipment Mechanics, Installers, and Repairers	2.02	$193,043.30	$33,247.89	$226,291.18	4,191.14
43-6000	Secretaries and Administrative Assistants	1.90	$137,294.52	$23,646.27	$160,940.79	3,348.80
53-3000	Motor Vehicle Operators	1.86	$152,568.73	$26,276.94	$178,845.69	3,811.08
53-7000	Material Moving Workers	1.80	$129,092.10	$22,233.55	$151,325.65	3,217.10
49-3000	Vehicle and Mobile Equipment Mechanics, Installers, and Repairers	1.72	$162,963.30	$28,067.20	$191,030.50	3,681.94
47-4000	Other Construction and Related Workers	1.36	$165,065.28	$28,429.23	$193,494.50	2,670.22
17-2000	Engineers	1.36	$189,000.36	$32,551.57	$221,551.93	2,721.18
17-3000	Drafters, Engineering Technicians, and Mapping Technicians	1.18	$104,757.88	$18,042.47	$122,800.36	2,294.74
13-2000	Financial Specialists	1.10	$142,549.32	$24,551.30	$167,100.62	2,188.56
11-3000	Operations Specialties Managers	1.10	$217,612.12	$37,479.38	$255,091.51	2,266.70
51-4000	Metal Workers and Plastic Workers	1.04	$102,142.95	$17,592.10	$119,735.05	2,114.66

Table 7.4 – Occupational Output from IMPLAN Construction Model, Indirect Jobs, Employment Greater than 1.0

This table is directly modeled for this project.

Occ Code	Occupation	Wage and Salary Employment	Wage and Salary Income	Supplements to Wages and Salaries	Employee Compensation	Hours Worked
47-2000	Construction Trades Workers	11.43	$642,526.19	$110,691.35	$753,217.54	22,019.23
47-1000	Supervisors of Construction and Extraction Workers	2.88	$216,774.62	$37,338.88	$254,113.50	6,310.93
13-1000	Business Operations Specialists	2.56	$233,626.65	$39,796.91	$273,423.56	5,226.78
11-9000	Other Management Occupations	2.15	$232,865.84	$40,011.54	$272,877.38	4,667.82
53-3000	Motor Vehicle Operators	1.19	$68,517.49	$12,735.48	$81,252.97	2,445.31
11-1000	Top Executives	1.04	$157,608.07	$26,891.68	$184,499.75	2,305.06

Table 7.5 – Occupational Output from IMPLAN Construction Model, Induced Jobs, Employment Greater than 1.0

This table is directly modeled for this project.

Occ Code	Occupation	Wage and Salary Employment	Wage and Salary Income	Supplements to Wages and Salaries	Employee Compensation	Hours Worked
41-2000	Retail Sales Workers	5.54	$158,584.33	$33,516.43	$192,100.75	7,468.59
35-3000	Food and Beverage Serving Workers	5.45	$131,901.42	$17,939.64	$149,841.07	5,998.12
29-1000	Healthcare Diagnosing or Treating Practitioners	2.95	$410,746.31	$79,679.43	$490,425.74	5,399.01
31-1100	Home Health and Personal Care Aides; and Nursing Assistants, Orderlies, and Psychiatric Aides	2.92	$89,722.08	$17,762.64	$107,484.72	4,643.78
35-2000	Cooks and Food Preparation Workers	2.60	$75,794.21	$10,759.59	$86,553.79	3,547.46
53-7000	Material Moving Workers	2.05	$77,682.21	$15,932.54	$93,614.75	3,221.07
43-4000	Information and Record Clerks	1.91	$84,992.04	$15,647.76	$100,639.80	3,106.57
13-1000	Business Operations Specialists	1.85	$170,108.63	$28,386.71	$198,495.35	3,534.26
29-2000	Health Technologists and Technicians	1.53	$81,460.20	$16,074.76	$97,534.97	2,666.90
11-1000	Top Executives	1.50	$197,599.96	$33,926.90	$231,526.85	3,179.78
43-6000	Secretaries and Administrative Assistants	1.25	$63,119.23	$11,110.63	$74,229.86	2,207.20
15-1200	Computer Occupations	1.23	$171,413.99	$27,112.74	$198,526.73	2,422.05
37-2000	Building Cleaning and Pest Control Workers	1.23	$32,825.14	$5,518.85	$38,344.01	1,947.08
31-9000	Other Healthcare Support Occupations	1.21	$52,233.23	$9,819.96	$62,053.19	1,983.83
53-3000	Motor Vehicle Operators	1.08	$57,290.35	$11,907.42	$69,197.76	2,094.16
35-9000	Other Food Preparation and Serving Related Workers	1.07	$23,668.30	$3,121.72	$26,790.03	1,060.25
35-1000	Supervisors of Food Preparation and Serving Workers	1.05	$50,431.06	$6,926.89	$57,357.94	1,743.38
11-9000	Other Management Occupations	1.01	$108,914.13	$18,827.69	$127,741.83	2,005.55

Bb

Battery Energy Storage Systems (BESS)

An array of hundreds or thousands of small batteries that enable energy from renewables, like solar and wind, to be stored and released at a later time.

Cc

Consumer Price Index (CPI)

An index of the changes in the cost of goods and services to a typical consumer, based on the costs of the same goods and services at a base period.

Dd

Direct impacts

During the construction period: the changes that occur in the on-site construction industries in which the direct final demand change is made.

During operating years: the final demand changes that occur in the on-site spending for the solar operations and maintenance workers.

Ee

Equalized Assessed Value (EAV)

The product of the assessed value of property and the state equalization factor. This is typically used as the basis for the value of property in a property tax calculation.

Ff

Full-time equivalent (FTE)

A unit that indicates the workload of an employed person. One FTE is equivalent to one worker working 2,080 hours in a year. One half FTE is equivalent to a half-time worker or someone working 1,040 hours in a year.

Hh

HV line extension

High-voltage electric power transmission links used to connect generators to the electric transmission grid.

Ii

IMPLAN (IMpact analysis for PLANning)

A business who is the leading provider of economic impact data and analytic applications. IMPLAN data is collected at the federal, state, and local levels and used to create state-specific and county-specific industry multipliers.

Indirect impacts

Impacts that occur in industries that make up the supply chain for that industry.

During the construction period: the changes in inter-industry purchases resulting from the direct final demand changes, including construction spending on materials and equipment and other purchases of goods and off-site services.

During operating years: the changes in inter-industry purchases resulting from the direct final demand changes.

Induced impacts

The changes that occur in household spending as household income increases or decreases as a result of the direct and indirect effects of final demand changes.

Inflation

A persistent rise in the general level of prices related to an increase in the volume of money and resulting in the loss of value of currency. Inflation is typically measured by the CPI.

Mm

Median Household Income (MHI)

The income amount that divides a population into two equal groups; half having an income above that amount and half having an income below that amount.

Millage rate

The tax rate, as for property, assessed in mills per dollar.

Multiplier

A factor of proportionality that measures how much a variable changes in response to a change in another variable.

MW

A unit of power, equal to one million watts or one thousand kilowatts.

MWac (megawatt alternating current)

The power capacity of a utility-scale solar PV system *after* its direct current output has been fed through an inverter to create an alternating current (AC). A solar system's rated MWac will always be lower than its rated MWdc due to inverter losses. AC is the form in which electric energy is delivered to businesses and residences and that consumers typically use when plugging electric appliances into a wall socket.

MWdc (megawatt direct current)

The power capacity of a utility-scale solar PV system *before* its direct current output has been fed through an inverter to create an alternating current. A solar system's rated MWdc will always be higher than its rated MWac.

Nn

Net economic impact

Total change in economic activity in a specific region, caused by a specific economic event.

Oo

Output

Economic output measures the value of goods and services produced in a given area. Gross Domestic Product is the economic output of the United States as a whole.

Pp

PV (photovoltaic) system

Solar modules, each comprising a number of solar cells, which generate electrical power.

Rr

Real Gross Domestic Product (GDP)

A measure of the value of goods and services produced in an area and adjusted for inflation over time.

Tt

Tax rate

The percentage (or millage) of the value of a property to be paid as a tax.

Total economic output

The quantity of goods or services produced in a given time period by a firm, industry, county, or country.

Uu

Utility-scale solar

Solar-powered electric generation facilities intended for wholesale distribution typically over 5MW in capacity.

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X. Curriculum Vitae (Abbreviated)

David G. Loomis
Strategic Economic Research, LLC
President

Education

Doctor of Philosophy, Economics, Temple University, Philadelphia, Pennsylvania, May 1995.

Bachelor of Arts, Mathematics and Honors Economics, Temple University, Magna Cum Laude, May 1985.

Experience

2011-present Strategic Economic Research, LLC

- Performed over 400 economic impact analyses on policy initiatives and energy projects such as wind energy, solar energy, natural gas plants and transmission lines at the county and state level
- Provided expert testimony over 90 times in formal proceedings before state legislative bodies, state public utility commissions, and county boards regarding wind, solar and transmission projects
- Grew the company from a single employee to a twenty-member staff team.

1996-2023 Illinois State University, Normal, IL

Professor Emeritus – Department of Economics (2023-present)

Full Professor – Department of Economics (2010-2023)

Associate Professor - Department of Economics (2002-2009)

Assistant Professor - Department of Economics (1996-2002)

- Taught Regulatory Economics; Telecommunications Economics and Public Policy; Industrial Organization and Pricing; Individual and Social Choice; Economics of Energy and Public Policy; and a Graduate Seminar Course in Electricity, Natural Gas, and Telecommunications Issues
- Supervised as many as 5 graduate students in research projects each semester
- Served on numerous departmental committees

1997-2023 Institute for Regulatory Policy Studies, Normal, IL

Executive Director (2005-2023)

Co-Director (1997-2005)

- Grew contributing membership from 5 companies to 16 organizations
- Doubled the number of workshop/training events annually
- Supervised 2 Directors, Administrative Staff and internship program
- Developed and implemented state-level workshops concerning regulatory issues related to the electric, natural gas, and telecommunications industries

2006-2018 Illinois Wind Working Group, Normal, IL

Director

- Founded the organization and grew the organizing committee to over 200 key wind stakeholders
- Organized annual wind energy conference with over 400 attendees
- Organized strategic conferences to address critical wind energy issues
- Initiated monthly conference calls to stakeholders
- Devised organizational structure and bylaws

2007-2018 Center for Renewable Energy, Normal, IL

Director

- Created founding document approved by the Illinois State University Board of Trustees and Illinois Board of Higher Education
- Secured over $150,000 in funding from private companies
- Hired and supervised 4 professional staff members and supervised 3 faculty members as Associate Directors
- Reviewed renewable energy manufacturing grant applications for Illinois Department of Commerce and Economic Opportunity for a $30 million program
- Created technical "Due Diligence" documents for the Illinois Finance Authority loan program for wind farm projects in Illinois
- Published 40 articles in leading journals such as AIMS Energy, Renewable Energy, National Renewable Energy Laboratory Technical Report, Electricity Journal, Energy Economics, Energy Policy, and many others
- Raised over $7.7 million in grants
- Raised over $2.7 million in external funding

Bryan A. Loomis
Strategic Economic Research, LLC
Vice President

Education

Master of Business Administration (M.B.A.), Belmont University, Nashville, Tennessee, 2017.

Experience

2019-present Strategic Economic Research, LLC, Bloomington, IL

- Serve as lead analyst on economic impact reports, overseeing all aspects of analysis and report creation.
- Communicate with developers about economic impact, property tax, and land use analyses
- Provide third-party expert testimony on behalf of developers for special use permitting hearings
- Conduct non-standard analyses and memos for unique energy-related projects, such as statewide legislation, property tax impacts on school district state aid, and analyzing eligibility for energy community bonus adders to tax credits
- Oversee improvements to both reports and team processes

Property Tax Analysis and Land Use Director (2019-2021)

- Directed the property tax analysis by training other associates on the methodology and overseeing the process for over twenty states
- Improved the property tax analysis methodology by researching various state taxing laws and implementing depreciation, taxing jurisdiction millage rates, and other factors into the tax analysis tool
- Executed land use analyses by running Monte Carlo simulations of expected future profits from farming and comparing that to the solar lease
- Performed economic impact modeling using JEDI and IMPLAN tools
- Improved workflow processes by capturing all tasks associated with economic modeling and report-writing, and created automated templates in Asana workplace management software

Expert Testimony

- Harper County (Kansas) Planning Board and Board of Zoning Appeals, on behalf of Flat Ridge Wind Farm (Invenergy), Direct Oral Testimony, October 18, 2022.
- Kingman County (Kansas) Planning Board and Board of Zoning Appeals, on behalf of Flat Ridge Wind Farm (Invenergy), Direct Oral Testimony, October 24, 2022.
- Logan County (Illinois) Board of Zoning Appeals, on behalf of Top Hat Wind Farm (Invenergy), Direct Oral Testimony, October 25, 2022.
- Knox County (Indiana) Board of Zoning Appeals, on behalf of Wheatland Solar Farm (Origis Energy), Direct Oral Testimony, November 1, 2022.
- Howard County (Indiana) Board of Zoning Appeals, on behalf of Emerald Green Solar Farm (Origis Energy), Direct Oral Testimony, February 28, 2023.
- Fulton County (Illinois) Board of Zoning Appeals, on behalf of South Fulton Solar Farm (Leeward), Direct Oral Testimony, March 1, 2023.

- Sedgwick County (Colorado) Board of Zoning Appeals, on behalf of Overland Pass East Solar Farm (National Renewable Solutions), Direct Oral Testimony, August 8, 2023.
- Dickinson and Emmet Counties (Kansas) Open House, on behalf of Red Rock Wind Farm (Invenergy), Subject Matter Expert, August 28-29, 2023.
- Vermilion County (Illinois) Board of Zoning Appeals, on behalf of Mural Solar Farm (Liberty Power), Direct Oral Testimony, January 10, 2024.

2019-2021 Viral Healthcare Founders LLC, Nashville, TN

CEO and Founder

- Founded and directed marketing agency for healthcare startups
- Managed three employees
- Mentored and worked with over 30 startups to help them grow their businesses
- Grew an email list to more than 2,000 and LinkedIn following to 3,500

Christopher Thankan
Strategic Economic Research, LLC
Director of Economic Impact Analysis

Education

Bachelor of Science in Sustainable & Renewable Energy (B.S.), Minor in Economics, Illinois State University, Summa Cum Laude, Normal, IL, 2021

Experience

2021-present Strategic Economic Research, LLC, Bloomington, IL

- Create economic impact results on numerous renewable energy projects Feb 2021-Present
- Utilize IMPLAN multipliers along with NREL's JEDI model for analyses
- Review project cost Excel sheets
- Conduct property tax analysis for different US states
- Research taxation in states outside research portfolio
- Complete ad hoc research requests given by the president
- Hosted a webinar on how to run successful permitting hearings
- Research school funding and the impact of renewable energy on state aid to school districts
- Quality check coworkers JEDI models
- Started more accurate methodology for determining property taxes that became the main process used

by Dr. David G. Loomis,
Bryan Loomis, and Chris Thankan

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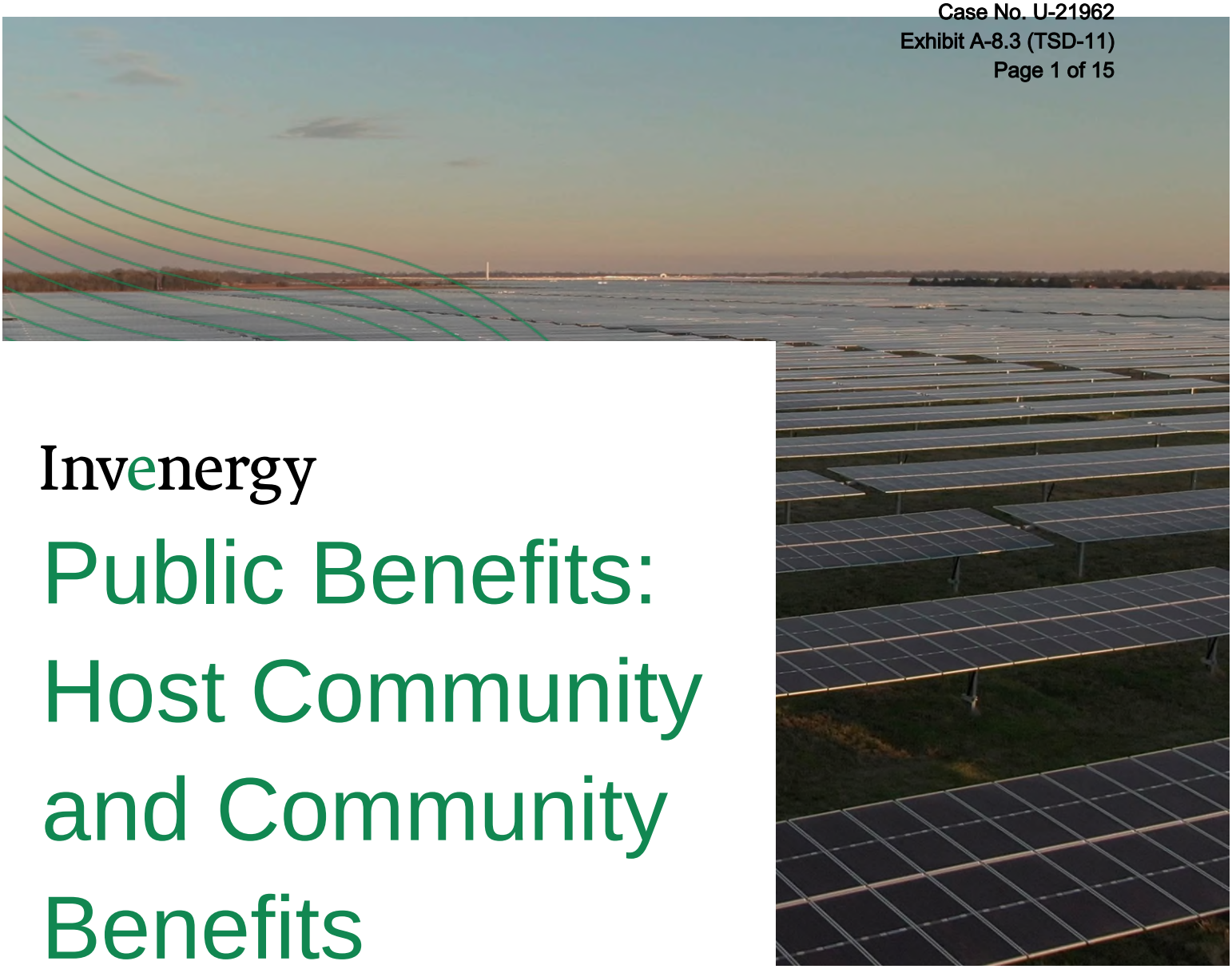

Invenergy

Public Benefits: Host Community and Community Benefits Agreements

Exhibit A-8.3 (TSD-11)

PREPARED FOR:

WASHTENAW SOLAR ENERGY LLC

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Invenergy

1.0 Public Benefits Agreements

1.1 Introduction

Washtenaw Solar Energy LLC ("Washtenaw Solar") is proposing a 150 MW solar facility located on privately-owned land in Saline Township, Washtenaw County, Michigan (the "Project"). As part of the 2023 PA 233 process, Washtenaw Solar has entered into certain agreements to provide benefits to Saline Township and the surrounding community. This exhibit summarizes the agreements that Washtenaw Solar contemplates as part of the Project.

1.2 Host Community Agreement

Washtenaw Solar proposed a Host Community Agreement to Saline Township to provide payment of $2,000 per megawatt ("MW") of nameplate capacity upon commencement of operation. The total benefit offered by the Host Community Agreement is $300,000. The Saline Township Board of Trustees approved this Agreement at its September 10, 2025, public meeting. A copy of the signed Host Community Agreement is provided as **Appendix A**.

1.3 Community Benefits Agreement

To meet the demonstrated capacity need of the Saline Area Fire Department (as discussed in the Fire Response Plan included as **Exhibit A-1.10 (JMP-4)**, Washtenaw Solar also proposed a Community Benefits Agreement to supply the Saline Area Fire Department with a new sports utility vehicle (2026 Chevy Tahoe), a trailer, and a four-person utility task vehicle to respond to emergencies occurring between the solar array areas. A copy of the Community Benefits Agreement proposed to the Saline Area Fire Department is included as **Appendix B**.

Appendices

Invenergy

2.0 Appendices

Appendix A: Host Community Agreement

HOST COMMUNITY AGREEMENT

This Host Community Agreement (this "Agreement") is entered into effective as of September 10, 2025 (the "Effective Date"), by and between Washtenaw Solar Energy LLC a Delaware limited liability company ("Washtenaw Solar") authorized to do business in the state of Michigan, and Saline Township, acting by and through its Township Board (the "Township Board"), herein sometimes referred to individually as a "Party" and collectively as the "Parties".

RECITALS

1. Washtenaw Solar is developing a 150 MW solar energy facility in Saline Township (the "Project").

2. Washtenaw Solar offered to make certain commitments to the Township Board in connection with the Project, and the Township Board has accepted those commitments as consideration for this Agreement.

AGREEMENT

NOW, THEREFORE, in consideration of the mutual promises contained herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereby agree as follows:

ARTICLE I

1.1 Community Benefit Commitments. Washtenaw Solar shall pay three-hundred thousand dollars ($300,000.00), calculated on the basis of two thousand dollars ($2,000.00) per megawatt of nameplate capacity of the Project, upon the commencement of operations date ("COD") of the Project. For purposes of this Agreement, the COD shall be defined as the date upon which the Project first delivers electricity to the electrical grid.

1.2 Defaults and Remedies. In the event of a breach by Washtenaw Solar of its obligations under this Agreement, the Township Board shall have the right to exercise all remedies that may be available at law or in equity and collect all costs incurred in enforcing this Agreement, including, but not limited to, reasonable attorneys' fees, subject to the limitations of this Agreement.

ARTICLE II

2.1 Notices. All notices, requests or statements shall be made in writing to the addresses set out below. Notices required to be in writing shall be delivered by hand, express courier, or electronic mail. All notices, requests, statements and other communications shall be deemed to have been duly given on (a) the date of delivery if delivered by hand or by express courier, (b) the time stamp upon delivery if sent by electronic mail; provided that deliveries under (b) shall be deemed to have been made upon the next business day if made after the close of business on any business day or on any other day. A Party may change its address by providing the other Party with at least three (3) days prior notice thereof in accordance herewith:

To Township Board:	Address: 4254 Arkona Road Saline, MI 48176 Attn: Township Supervisor cc Township Clerk E-mail: salinetownship@gmail.com With copy to: Frederick Lucas, Township Attorney
To Washtenaw Solar	Address: One South Wacker Drive, Suite 1500, Chicago, IL 60606 Attn: General Counsel E-mail: generalcounselforwarding@invenergy.com Phone: 312-224-1400 Fax: 312-224-1444

ARTICLE 2

MISCELLANEOUS

2.2 **Entirety.** This Agreement constitutes the entire agreement between the Parties and supersedes all prior or contemporaneous discussions, agreements, proposals, solicitations, terms and conditions, and representations of the Parties affecting the same subject matter.

2.3 **Amendment; Termination.** No amendment, modification or change to this Agreement shall be enforceable unless set forth in writing and executed by both Parties. This Agreement shall terminate in the following circumstances:

a. By agreement, in writing, by both Parties;

b. If the Project has begun Decommissioning, which is initiated by any of the following:

i. The Project is no longer in production of energy or the condition of the Project is no longer producing capital revenue from electric power generation.

ii. The system electrical generation is terminated for reasons other than Operations and Maintenance for a duration not to exceed 180 days.

iii. The system is damaged by an Act-of-God, and the system is no longer considered recoverable.

iv. If after 30 years of life, and the Washtenaw Solar cannot secure agreements to continue the operation of the Project.

2.4 **Choice of Law and Forum.** This Agreement shall be governed, construed, enforced and performed in accordance with Michigan law, without regard to principles of conflicts of law. Any and all litigation arising out of or relating to this Agreement shall be brought and maintained exclusively in the federal or state courts sitting in Washtenaw County, Michigan. To the extent permissible under applicable Law, each Party irrevocably waives its respective rights to a jury trial of any claim in any court in any jurisdiction based upon or arising out of or relating to this Agreement. The Parties irrevocably and unconditionally submit to the jurisdiction and venue of any federal or state courts sitting in Washtenaw County, Michigan, over any litigation arising out of or relating to this Agreement.

2.5 **Relationships of Parties**. The Parties shall not be deemed to be in a relationship of partners or joint venturers by virtue of this Agreement, nor shall any Party be an agent, representative, trustee or fiduciary of the other Party. Neither Party shall have any authority to bind the other to any agreement.

2.6 **Counterparts**. This Agreement may be executed in several counterparts, each of which is an original and all of which constitute one and the same instrument. Delivery of an executed counterpart of this Agreement by electronic pdf transmission will be deemed as effective delivery of an originally executed counterpart.

2.7 **Consequential Damages; Limitation of Liability**. IN NO EVENT SHALL EITHER PARTY OR ANY OF ITS AFFILIATES, DIRECTORS, EMPLOYEES, ATTORNEYS OR AGENTS BE LIABLE TO THE OTHER PARTY OR ANY OF ITS AFFILIATES, DIRECTORS, EMPLOYEES, ATTORNEYS OR AGENTS FOR ANY SPECIAL, INCIDENTAL, CONSEQUENTIAL, PUNITIVE OR EXEMPLARY DAMAGES (INCLUDING DAMAGES FOR LOST OPPORTUNITY, LOST PROFITS OR REVENUES OR LOSS OF USE OF SUCH PROFITS OR REVENUES) (WHETHER OR NOT THE CLAIM THEREFORE IS BASED ON CONTRACT, TORT, DUTY IMPOSED BY LAW OR OTHERWISE), IN CONNECTION WITH, ARISING OUT OF OR IN ANY WAY RELATED TO, THE PROJECT OR ANY ACT OR OMISSION OR EVENT OCCURRING IN CONNECTION THEREWITH; AND EACH PARTY HEREBY WAIVES, RELEASES AND AGREES NOT TO SUE UPON ANY SUCH CLAIM FOR ANY SUCH SPECIAL, INCIDENTAL, CONSEQUENTIAL, PUNITIVE OR EXEMPLARY DAMAGES, WHETHER OR NOT ACCRUED AND WHETHER OR NOT KNOWN OR SUSPECTED TO EXIST IN ITS FAVOR. EACH PARTY'S AGGREGATE LIABILITY TO THE OTHER PARTY ARISING OUT OF OR RELATED TO THE PROJECT, WHETHER IN CONTRACT, TORT (INCLUDING NEGLIGENCE), OR OTHERWISE, SHALL NOT EXCEED, IN THE AGGREGATE, AN AMOUNT EQUAL TO FIFTY THOUSAND DOLLARS ($50,000).

2.8 **Assignment.** This Agreement and all rights and obligations hereunder may be assigned, delegated, or otherwise transferred, in whole or in part, by either Party hereto without the consent of the other Party. Any such assignment shall be effective upon written notice to the non-assigning Party.

2.9 **Successors and Assigns.** This Agreement shall be binding and inure to the benefit of the Parties and their respective successors and assigns.

IN WITNESS WHEREOF, the Parties have executed this Agreement as of the Effective Date. This Agreement shall not become effective as to either Party unless and until executed by both Parties.

SALINE TOWNSHIP, acting by and through the Township Board

By: James C. Marion
Name:
Title Supervisor

Washtenaw Solar Energy LLC
By Invenergy LLC, its Manager

By: Kelly Marion
Name:
Title: Cuch

IN WITNESS WHEREOF, the Parties have executed this Agreement as of the Effective Date. This Agreement shall not become effective as to either Party unless and until executed by both Parties.

SALINE TOWNSHIP, acting by and through the Township Board

By:_____
Name:
Title

DS
Legal Reviewed
MAH

Washtenaw Solar Energy LLC
By Invenergy LLC, its Manager

Signed by:
By:_____
EB4B0326408A4CC...
Name: Michael Kaplan
Title: Authorized Signatory

Invenergy

Appendix B: Community Benefits Agreement

COMMUNITY BENEFITS AGREEMENT

This Community Benefits Agreement (this "Agreement") is entered into effective as of _____, 2025 (the "Effective Date"), by and between Washtenaw Solar Energy LLC a Delaware limited liability company ("Washtenaw Solar") authorized to do business in the state of Michigan, and the Saline Area Fire Department (the "SAFD"), herein sometimes referred to individually as a "Party" and collectively as the "Parties".

RECITALS

1. Washtenaw Solar is developing a 150 MW solar energy facility within the response area of the SAFD (the "Project").

2. Washtenaw Solar offered to make certain commitments to the SAFD in connection with the Project, and the SAFD has accepted those commitments as consideration for this Agreement.

AGREEMENT

NOW, THEREFORE, in consideration of the mutual promises contained herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereby agree as follows:

ARTICLE 1

1.**1 Community Benefit Commitments.** Pursuant to Michigan Compiled Laws Section 460.1227 and in response to an SAFD analysis of additional specific equipment and training needed to address existing deficiencies in local emergency response capacity, Washtenaw Solar makes the following commitments to the SAFD:

ARTICLE 1 Washtenaw Solar will provide an initial payment of One-Hundred-Ten Thousand and No/100 Dollars ($110,000.00) to the SAFD within thirty (30) days of final approval by the Michigan Public Service Commission of a Certificate to own, construct, and operate the Project (the "Initial Payment"). The Initial Payment shall be used to equip the fire and emergency responders with proper equipment needed to address existing deficiencies in response capacity for possible emergency situations related to the Project.

a. Specified additional equipment needs identified by the SAFD analysis include a 2026 Chevy Tahoe with the third row deleted, a 4-person utility task vehicle (UTV), and a trailer.

b. Beginning on the first anniversary of the of the Initial Payment date and continuing through the date decommissioning begins on the Project, Washtenaw Solar shall make a recurring annual payment of Five Thousand and No/100 Dollars ($5,000.00) to the SAFD to cover the cost of any additional equipment and training needed to respond to emergency situations related to the Project.

1.2 **Defaults and Remedies.** In the event of a breach by Washtenaw Solar of its obligations under this Agreement, the SAFD shall have the right to exercise all remedies that may be available at law or in equity and collect all costs incurred in enforcing this Agreement, including, but not limited to, reasonable attorneys' fees, subject to the limitations of this Agreement.

ARTICLE 2

2.1 **Notices.** All notices, requests or statements shall be made in writing to the addresses set out below. Notices required to be in writing shall be delivered by hand, express courier, or electronic mail. All notices, requests, statements and other communications shall be deemed to have been duly given on (a) the date of delivery if delivered by hand or by express courier, (b) the time stamp upon delivery if sent by electronic mail; provided that deliveries under (b) shall be deemed to have been made upon the next business day if made after the close of business on any business day or on any other day. A Party may change its address by providing the other Party with at least three (3) days prior notice thereof in accordance herewith:

To SAFD:	Address: 205 E. Michigan Avenue Attn: Chief Jason Sperle E-mail: sperle@salinefire.com With copy to: [NAME]
To Washtenaw Solar	Address: One South Wacker Drive, Suite 1500, Chicago, IL 60606 Attn: General Counsel E-mail: generalcounsel@invenergy.com Phone: 312-224-1400 Fax: 312-224-1444

ARTICLE 3

MISCELLANEOUS

1.3 **Entirety.** This Agreement constitutes the entire agreement between the Parties and supersedes all prior or contemporaneous discussions, agreements, proposals, solicitations, terms and conditions, and representations of the Parties affecting the same subject matter.

1.4 **Amendment; Termination.** No amendment, modification or change to this Agreement shall be enforceable unless set forth in writing and executed by both Parties. This Agreement shall terminate in the following circumstances:

DRAFT

a. By agreement, in writing, by both Parties;

b. If the Project has begun Decommissioning, which is initiated by any of the following:

i. The Project is no longer in production of energy or the condition of the Project is no longer producing capital revenue from electric power generation.

ii. The system electrical generation is terminated for reasons other than Operations and Maintenance for a duration not to exceed 180 days.

iii. The system is damaged by an Act-of-God, and the system is no longer considered recoverable.

iv. If after 30 years of life, and the Washtenaw Solar cannot secure agreements to continue the operation of the Project.

1.5 Choice of Law and Forum. This Agreement shall be governed, construed, enforced and performed in accordance with Michigan law, without regard to principles of conflicts of law. Any and all litigation arising out of or relating to this Agreement shall be brought and maintained exclusively in the federal or state courts sitting in Washtenaw County, Michigan. To the extent permissible under applicable Law, each Party irrevocably waives its respective rights to a jury trial of any claim in any court in any jurisdiction based upon or arising out of or relating to this Agreement. The Parties irrevocably and unconditionally submit to the jurisdiction and venue of any federal or state courts sitting in Washtenaw County, Michigan, over any litigation arising out of or relating to this Agreement.

1.6 Relationships of Parties. The Parties shall not be deemed to be in a relationship of partners or joint venturers by virtue of this Agreement, nor shall any Party be an agent, representative, trustee or fiduciary of the other Party. Neither Party shall have any authority to bind the other to any agreement.

1.7 Counterparts. This Agreement may be executed in several counterparts, each of which is an original and all of which constitute one and the same instrument. Delivery of an executed counterpart of this Agreement by electronic pdf transmission will be deemed as effective delivery of an originally executed counterpart.

1.8 Consequential Damages; Limitation of Liability. IN NO EVENT SHALL EITHER PARTY OR ANY OF ITS AFFILIATES, DIRECTORS, EMPLOYEES, ATTORNEYS OR AGENTS BE LIABLE TO THE OTHER PARTY OR ANY OF ITS AFFILIATES, DIRECTORS, EMPLOYEES, ATTORNEYS OR AGENTS FOR ANY SPECIAL, INCIDENTAL, CONSEQUENTIAL, PUNITIVE OR EXEMPLARY DAMAGES (INCLUDING DAMAGES FOR LOST OPPORTUNITY, LOST PROFITS OR REVENUES OR LOSS OF USE OF SUCH PROFITS OR REVENUES) (WHETHER OR NOT THE CLAIM THEREFORE IS BASED ON CONTRACT, TORT, DUTY IMPOSED BY LAW OR OTHERWISE), IN

DRAFT

CONNECTION WITH, ARISING OUT OF OR IN ANY WAY RELATED TO, THE PROJECT OR ANY ACT OR OMISSION OR EVENT OCCURRING IN CONNECTION THEREWITH; AND EACH PARTY HEREBY WAIVES, RELEASES AND AGREES NOT TO SUE UPON ANY SUCH CLAIM FOR ANY SUCH SPECIAL, INCIDENTAL, CONSEQUENTIAL, PUNITIVE OR EXEMPLARY DAMAGES, WHETHER OR NOT ACCRUED AND WHETHER OR NOT KNOWN OR SUSPECTED TO EXIST IN ITS FAVOR. EACH PARTY'S AGGREGATE LIABILITY TO THE OTHER PARTY ARISING OUT OF OR RELATED TO THE PROJECT, WHETHER IN CONTRACT, TORT (INCLUDING NEGLIGENCE), OR OTHERWISE, SHALL NOT EXCEED, IN THE AGGREGATE, AN AMOUNT EQUAL TO FIFTY THOUSAND DOLLARS ($50,000).

1.9 **Assignment.** This Agreement and all rights and obligations hereunder may be assigned, delegated, or otherwise transferred, in whole or in part, by either Party hereto without the consent of the other Party. Any such assignment shall be effective upon written notice to the non-assigning Party.

2.9 **Successors and Assigns.** This Agreement shall be binding and inure to the benefit of the Parties and their respective successors and assigns.

IN WITNESS WHEREOF, the Parties have executed this Agreement as of the Effective Date. This Agreement shall not become effective as to either Party unless and until executed by both Parties.

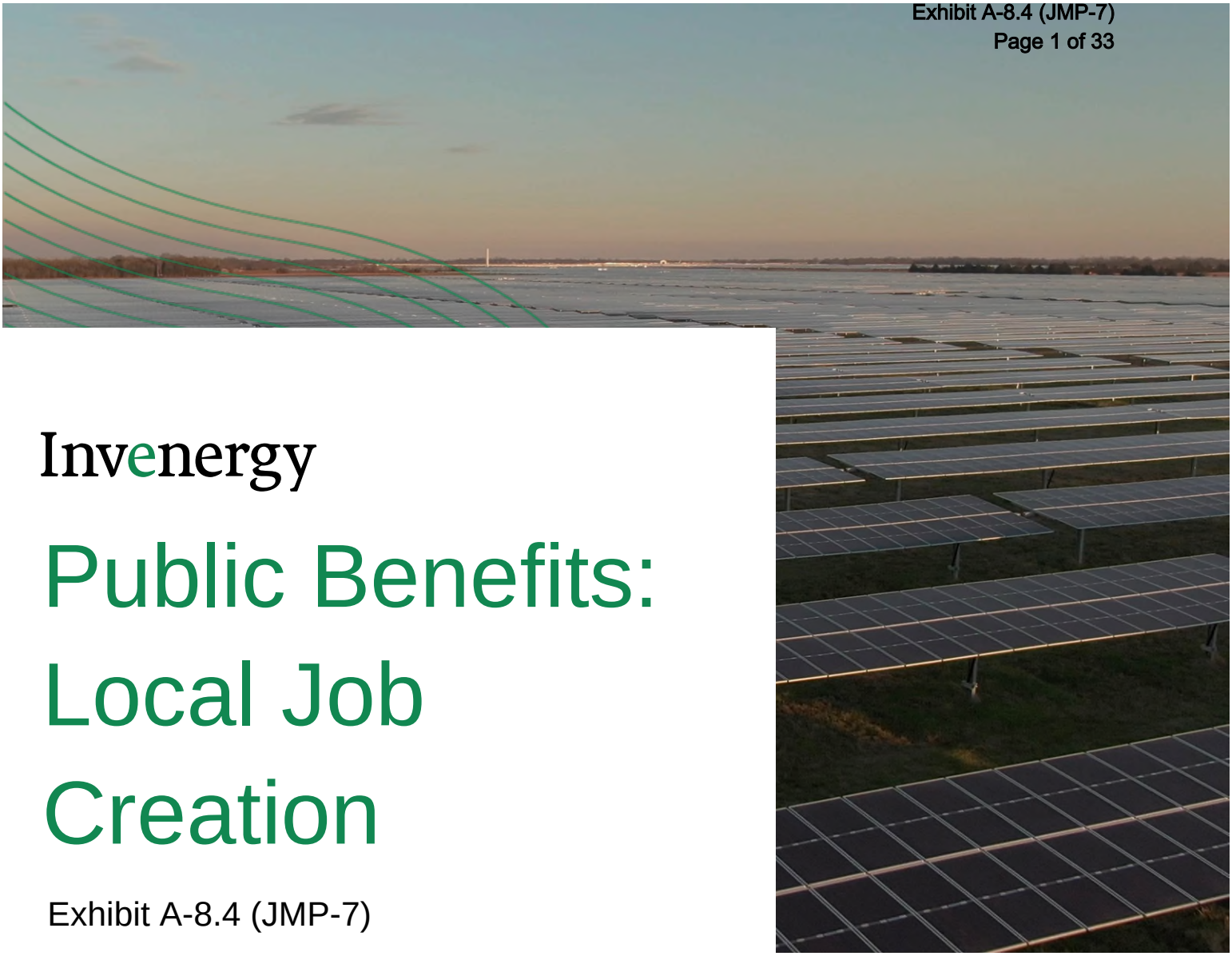
Saline Area Fire Department

By:_____
Name:
Title:

Washtenaw Solar Energy LLC
By Invenergy LLC, its Manager

By:_____
Name:
Title:

DRAFT



Invenergy

Public Benefits: Local Job Creation

Exhibit A-8.4 (JMP-7)

PREPARED FOR:

WASHTENAW SOLAR ENERGY LLC

Invenergy

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1.0 Local Job Creation

1.1 Introduction

Washtenaw Solar Energy LLC ("Washtenaw Solar") is proposing a 150 MW solar facility located on privately-owned land in Saline Township, Washtenaw County, Michigan (the "Project"). The Project is expected to create hundreds of local construction jobs.

1.2 Commitments

Under 2023 PA 233 ("PA 233"), Washtenaw Solar must make certain commitments with regard to labor and employment during construction. These commitments include:

> (i) The installation, construction, or construction maintenance of the energy facility will use apprenticeship programs registered and in good standing with the United States Department of Labor under the national apprenticeship act, 29 USC 50 to 50c.
>
> (ii) The workers employed for the construction or construction maintenance of the energy facility will be paid a minimum wage standard not less than the wage and fringe benefit rates prevailing in the locality in which the work is to be performed as determined under 2023 PA 10, MCL 408.1101 to 408.1126, or 40 USC 3141 to 3148, whichever provides the higher wage and fringe benefit rates.
>
> (iii) To the extent permitted by law, the entities performing the construction or construction maintenance work will enter into a project labor agreement or operate under a collective bargaining agreement for the work to be performed.

The letter included as **Appendix A** provides a commitment from Washtenaw Solar with regard to each requirement above. To demonstrate Washtenaw Solar's commitment to enter into a project labor agreement, Washtenaw Solar must provide the Commission with a copy of the applicable agreement. Washtenaw Solar and its construction contractors operate under the National Maintenance Agreement ("NMA") included as **Appendix B**. Washtenaw Solar has also identified below the specific provisions of the National Maintenance Agreement that qualify it as a Project Labor Agreement under PA 233.

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Statute	Requirement	NMA Provision
MCL 460.1221(u)(i)	Binds all contractors and subcontractors on the construction project through the inclusion of appropriate specifications in all relevant solicitation provisions and contract documents.	The NMA provides, "All subcontracting of work at any tier covered by this Agreement shall be performed under this Agreement, other NMA(s), or any agreement approved as compatible by the NMAPC." Agreement, art V, § 1, p 9.
MCL 460.1221(u)(ii)	Allows all contractors and subcontractors on the construction project to compete for contracts and subcontracts without regard to whether they are otherwise parties to collective bargaining agreements.	The NMA provides, "This Agreement is a stand alone agreement and none of the provisions in any local, regional, area or national collective bargaining agreement shall apply, unless specifically incorporated in this Agreement. Furthermore, this Agreement is the exclusive collective bargaining agreement for any work to which it is extended, and for such work it supersedes and overrides the terms and conditions of any and all other national, area, or local collective bargaining agreements to which the parties hereto, or either of them may be signatory." Agreement, art XXVII, § 4.
MCL 460.1221(u)(iii)	Contains guarantees against strikes, lockouts, and similar job disruptions.	The NMA provides, "During the term of this Agreement, there shall be no lockouts by the Employer and no strikes, picketing, work stoppages, slowdowns or other disruptive activity for any reason by the Union or by any employee." Agreement, art XXII, § 1, p 17.
MCL 460.1221(u)(iv)	Sets forth the effective, prompt, and mutually binding procedures for resolving labor disputes arising during the term of the project labor agreement.	The NMA provides, "Since presently established jurisdictional dispute settlement procedures are not applicable to work covered by the Agreement, all signatory Unions and all Employers, signatory to this or any other NMA, stipulate that they will abide by the following procedures for the resolution of jurisdictional disputes." Agreement, art I, § 6, p 7; see also *id.* §§ 7–12, pp 7–8 (detailing such procedures).

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Statute	Requirement	NMA Provision
MCL 460.1221(u)(v)	Provides other mechanisms for labor-management cooperation on matters of mutual interest and concern, including productivity, quality of work, safety, and health.	The NMA seeks to "improve safety, productivity, and quality." See Agreement, art XXIV, § 1, p 20. The NMA provides, "The Union and the Employer understand that the Owner may choose to perform, directly subcontract, or purchase any part or parts of the work necessary on the project with due consideration given to achieving the highest standards and harmonious working conditions herein." Agreement, art IV, § 3, p 9. The NMA also provides, "If the Employer considers it necessary to shut down work to avoid endangering the life or the safety of its employees the Employer will not be in violation of this Agreement." Agreement, art XII, § 1, p 12–13.
MCL 460.1221(u)(vi)	Complies with all state and federal laws, rules, and regulations.	The NMA provides, "Any provisions in this Agreement which are in contravention of any Federal, State, Local or County regulations or laws affecting all or part of the limits covered by this Agreement shall be suspended in operation within the limits to which such laws or regulations are in effect." Agreement, art XX, § 1, p 16.

Appendices

2.0 Appendices

Appendix A: Commitment Letter

Invenergy

One South Wacker Drive | Suite 1500 | Chicago, Illinois 60606
T 312-224-1400 | F 312-224-1444

Michigan Public Service Commission
7109 W. Saginaw Highway
Lansing, MI 48917

Re: Construction Labor and Employment Commitments for Washtenaw Solar

Dear Commissioners:

I am reaching out as a representative of Invenergy with the authority to make commitments regarding construction labor and employment for Invenergy's proposed Washtenaw Solar Energy LLC ("Washtenaw Solar") 150 MW solar facility sited on privately-owned land within Saline Township, Washtenaw County, Michigan (the "Project"). Pursuant to Public Act 233 of 2023, Washtenaw Solar is committed to the following:

The installation, construction, or construction maintenance of the Project will use apprenticeship programs registered and in good standing with the United States Department of Labor under the national apprenticeship act, 29 USC 50 to 50c.

The workers employed for the construction or construction maintenance of the Project will be paid a minimum wage standard not less than the wage and fringe benefit rates prevailing in the locality in which the work is to be performed as determined under 2023 PA 10, MCL 408.1101 to 408.1126, or 40 USC 3141 to 3148, whichever provides the higher wage and fringe benefit rates.

To the extent permitted by law, Washtenaw Solar will require that its contractors performing the construction or construction maintenance work will enter into a project labor agreement or operate under a collective bargaining agreement for the work to be performed.

Washtenaw Solar's goal is to ensure fair labor practices, support local workforce development, and maintain smooth project execution with minimal disruptions. These commitments also help attract skilled labor, encourage local hiring, and strengthen community relationships.

If you have any questions or would like additional details, please feel free to contact me.

Respectfully,

DocuSigned by:
Michael Bessell
336375A2BFAB484...

Michael Bessell,
Senior Vice President
Authorized Signatory, Invenergy LLC as
Manager of Washtenaw Solar Energy LLC
invenergy.com

Invenergy

Appendix B: National Maintenance Agreement

NMAPC

NATIONAL MAINTENANCE AGREEMENTS POLICY COMMITTEE, INC.

National Maintenance Agreement

Building a Partnership of Safety, Productivity, Quality, and Strength

Effective January 1, 2012

MISSION STATEMENT
NATIONAL MAINTENANCE AGREEMENTS

BUILDING A PARTNERSHIP
OF
SAFETY, PRODUCTIVITY, QUALITY AND STRENGTH

Since its inception in 1971, the National Maintenance Agreements Policy Committee, Inc. Program (NMAPC Program) has been administered under a system of tripartite governance and cooperation, with Owners, Contractors and building trades Craft Workers sharing equally in the responsibilities and rewards generated by the NMAPC Program.

Understanding that the NMAPC Program's viability is equal only to the sum of its parts, careful consideration has been given over the years to ensure that proper balance is maintained among the three participants in the NMAPC Program. Such balance is necessary if the NMAPC Program is to maintain its stated goal of "Building a Partnership of Safety, Productivity, Quality and Strength."

In achieving that goal, the National Maintenance Agreements Policy Committee, Inc. (NMAPC) recognizes and addresses the following common concerns of the partners:

- Safety in all phases of work
- No disruptions of Owner's work
- Performance on schedule
- Cost-effective and quality craftsmanship
- Productivity flexibility
- A trained, available workforce
- Attainable work opportunities
- Resolution process for job site issues
- Consistent terms and conditions

By recognizing, addressing, and delivering on these concerns, the NMAPC Program reflects a true partnership dedicated to providing the most effective tool for the performance of work in industrial construction maintenance.

The NMAPC Program is administered and guided by the NMAPC. The NMAPC is a joint committee of labor and management representatives committed to achieving the NMAPC Program's stated goals and satisfying the individual and collective concerns of the participants.

Thus, the NMAPC provides a guarantee to Owners, Contractors and Craft Workers that the NMAPC Program will continue to deliver dynamic leadership in addressing the realities of industrial construction, maintenance, repair, replacement, renovation, and modernization, and that it will continue to provide a state of the art delivery system for the performance of such work. The NMAPC is truly designed to deliver partnerships of "Safety, Productivity, Quality and Strength."

NMAPC Tripartite Principles of Conduct: Contractors and Subcontractors

Since its inception in 1971, the National Maintenance Agreements Policy Committee, Inc. (NMAPC) Program has been administered under a system of tripartite governance and cooperation, with Owners, Contractors and building trades Craft Workers sharing equally in the responsibilities and rewards generated by the NMAPC Program. It is under this philosophy of tripartite cooperation and mutually beneficial relationships that the NMAPC has developed three (3) Tripartite Principles of Conduct, to ensure that the Program's stated goal of "Building a Partnership of Safety, Productivity, Quality and Strength" is adhered to in all phases of work.

NMAPC Contractors and Subcontractors shall:

1. Maintain a Zero Injury, drug-free and productive work place;

2. Be signatory to each Participating Union's National Maintenance Agreement (NMA) that you will be employing for the work in question;

3. Have filed and received approval of Site Extension Requests (SERs) of the NMAs at any and all affected facilities/locations prior to commencing with work;

4. Ensure that all subcontractors under your company's direction are performing work under the terms and conditions of the NMAs as outlined in 1) & 2);

5. Conduct mandatory Pre-job Conferences, as well as initiate addressing any potential concerns at such time as outlined in Article I of the NMA;

6. Adhere to and enforce the respective International Unions' Codes/Standards of Excellence;

7. Report your work hours performed under the NMAs on a quarterly basis via **www.nmapc.org**;

8. Maintain channels of communication with your Union(s), the local building trades council, and the Owner/Client, as well as participate in local tripartite meetings as necessary;

9. Familiarize and utilize existing resolution processes for addressing any disputes that may arise while working under the NMA Program;

10. Consistently adhere to, and enforce ALL of the terms and conditions of the NMAs, recognizing that it is every Signatory Contractor's and Subcontractor's responsibility to manage all aspects of their work performed under the Agreements.

NMAPC Tripartite Principles of Conduct: Unions

Since its inception in 1971, the National Maintenance Agreements Policy Committee, Inc. (NMAPC) Program has been administered under a system of tripartite governance and cooperation, with Owners, Contractors and building trades Craft Workers sharing equally in the responsibilities and rewards generated by the NMAPC Program. It is under this philosophy of tripartite cooperation and mutually beneficial relationships that the NMAPC has developed three (3) Tripartite Principles of Conduct, to ensure that the Program's stated goal of "Building a Partnership of Safety, Productivity, Quality and Strength" is adhered to in all phases of work.

NMAPC Participating International & Local Unions shall:

1. Maintain a Zero Injury, drug-free and productive work place;

2. Take appropriate and timely action regarding requests to become signatory to the National Maintenance Agreement (NMA), and Site Extension Requests (SERs);

3. Participate in all mandatory Pre-job Conferences and initiate addressing any potential concerns at such time as outlined in Article I of the NMA;

4. Ensure there are NO disruptions of any and all work performed under the NMAPC Program;

5. Adhere to and enforce the respective International Unions' Codes/Standards of Excellence;

6. Fulfill the promise of providing a highly skilled, trained, and professional workforce;

7. Maintain channels of communication with your NMAPC Contractors, the local building trades council, and the Owner/Client, as well as participate in local tripartite meetings as necessary;

8. Familiarize and utilize existing resolution processes for addressing any disputes that may arise while working under the NMA Program;

9. Always respect the Owner/Client's and the Contractor's property, equipment and tools;

10. Consistently adhere to ALL of the terms and conditions of the NMAs;

11. Remember that the work you perform and the way you perform it each day on the job could ultimately impact the opportunity for your fellow union members and your Contractors to work for this Owner/Client in the future.

NMAPC Tripartite Principles of Conduct: Owners

Since its inception in 1971, the National Maintenance Agreements Policy Committee, Inc. (NMAPC) Program has been administered under a system of tripartite governance and cooperation, with Owners, Contractors and building trades Craft Workers sharing equally in the responsibilities and rewards generated by the NMAPC Program. It is under this philosophy of tripartite cooperation and mutually beneficial relationships that the NMAPC has developed three (3) Tripartite Principles of Conduct, to ensure that the Program's stated goal of "Building a Partnership of Safety, Productivity, Quality and Strength" is adhered to in all phases of work.

Owner/Clients shall:

1. Embrace and promote the Zero Injury philosophy on all projects performed under the NMAPC Program;

2. Provide work opportunities to NMAPC Contractors and NMAPC Participating Unions;

3. Establish local tripartite committee(s) in order to maintain channels of communication with NMAPC Contractors, Participating Unions, the local building trades councils, and the NMAPC Administrative Office as well as participate in pre-job conferences;

4. Ensure Contractors are in possession of approved Site Extension Requests (SERs) at your facility(s) prior to commencing with work by utilizing the Owner/Client portal on **www.nmapc.org**;

5. Ensure Contractors are reporting work hours performed under the National Maintenance Agreements (NMAs) at your facility(s) on a quarterly basis via www.nmapc.org;

6. Make all Owner/Client rules and regulations known in advance to all parties;

7. Consider designating your projects or sites under the NMAPC "Yellow Card" in order to achieve the maximum benefits of the spirit and intent of the NMAPC Program;

8. Provide reasonable access to Union representatives to NMA jobs operated within your plant location(s).

NATIONAL MAINTENANCE AGREEMENTS
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NATIONAL MAINTENANCE AGREEMENT

This Agreement is entered into this _____day of _____ 20___, by and between _____SAMPLE_____
(Employer)
of_____, (hereinafter referred to as the Employer)
(City) (State)
and the CRAFT NAME (hereinafter referred to as the Union), for the purpose of industrial construction, maintenance, repair, replacement, renovation, and modernization work performed by the Employer in various plants.

ARTICLE I – RECOGNITION

1. The bargaining unit under this Agreement shall comprise the Union on behalf of (*CRAFT NAME*) employees of the Employer, now employed and employed in the future for industrial construction, maintenance, repair, replacement, renovation, and modernization in various plants within the geographical jurisdiction of the (*CRAFT NAME*). This Agreement does not apply to general superintendents, superintendents, assistant superintendents, office and clerical employees, watchmen or other professional or supervisory employees as defined in the National Labor Relations Act, as amended.

2. It is agreed between the Union and the Employer that this Agreement is applicable to industrial construction, maintenance, repair, replacement, renovation, and modernization work that is primarily within the recognized and traditional jurisdiction of the Union and shall be performed in accordance with the terms of this Agreement. It is further agreed that should the plant owner also award work to the Employer that is within the recognized and traditional jurisdiction of another Union with which the Employer has a similar agreement for the performance of that work, then work assignments shall be made in accordance with Agreements and Decisions of Record, attested Agreements, established trade practice, or prevailing area practice.

3. The Employer is required to conduct a pre-job conference, including craft work assignments, for each project performed under the National Maintenance Agreements (NMA). Written craft work assignments will be distributed to the appropriate Unions, not to exceed ten (10) working days after the pre-job conference. Pre-job conferences may be performed via teleconference. It is the responsibility of the Employer to notify the appropriate Building Trades Council having jurisdiction, as well as all International Unions, of the time and place of the pre-job conference. A pre-job conference outline can be obtained from the NMAPC office and/or any participating International Union. Failure to comply with this Section is a violation of this Agreement. All signatory Unions and signatory Contractors stipulate that failure to hold a pre-job conference is a grievable offense and shall result in a $500 penalty, payable to a designated NMAPC Fund.

4. For short term (less than 5 working days) or weekend projects, the Employer may contact the appropriate crafts via telephone, FAX or e-mail regarding work assignments. For projects of longer duration, the Employer shall convene a pre-job conference, upon sufficient notice so that all appropriate crafts have an opportunity to participate.

5. During the existence of the Agreement, there shall be no strikes, lockouts, work stoppages, or picketing arising out of any jurisdictional dispute. Work will continue as originally assigned, pending resolution of the dispute.

6. Since presently established jurisdictional dispute settlement procedures are not applicable to work covered by the Agreement, all signatory Unions and all Employers, signatory to this or any other NMA, stipulate that they will abide by the following procedures for the resolution of jurisdictional disputes. A party challenging an assignment shall notify all affected parties, i.e. Unions and Employer, by mail, FAX, or e-mail. All disputes involving craft work assignments shall be referred to the International Unions, with which the Local Unions are affiliated, providing the International Union and the Employer an opportunity to resolve the dispute.

7. If the International Unions and the Employer fail to resolve the dispute after five (5) working days from the date they were notified of the dispute any International Union or Employer directly involved in the dispute may refer the matter to arbitration via letter, FAX, or e-mail to the NMAPC Impartial Secretary for resolution under this procedure. Any party referring the matter to the Permanent Umpire must include written evidence that the affected International Unions attempted to resolve said dispute.

8. The Umpire will schedule and hold a hearing within seven (7) working days of the referral of the dispute. The Umpire shall notify the Employer and the appropriate International Unions by FAX and/or e-mail of the place and time chosen for the hearing. The Employer and International Unions party to a dispute will be allowed to have only one (1) representative from each party personally appear at any hearing scheduled by the Umpire. Participation in a hearing through either a personal appearance by outside legal counsel on behalf of a party or telephonically by any party will not be allowed. A party's failure to attend the hearing, without good cause, as determined by the Umpire, shall not delay the hearing of evidence or issuance of a decision by the Umpire. The time period set forth herein can be extended by mutual written agreement of the parties.

9. The Umpire shall issue a decision within three (3) working days after the case has been closed. The decision of the Umpire shall be final and binding on all parties to the dispute and shall be predicated upon the particular facts and evidence presented regarding this dispute and shall be effective only on the particular job in question.

10. In rendering a decision, the Umpire shall determine:

a. First, whether a previous agreement of record or applicable agreement, including a disclaimer agreement, between the National and International Unions to the dispute governs;

b. Only if the Umpire finds that the dispute is not covered by an appropriate or applicable agreement of record or agreement between the crafts to the dispute, shall consideration be given to the established trade practice in the industry and prevailing practice in the locality. Where there is a previous decision of record governing the case, the Umpire shall give equal weight to such decision of record, unless the prevailing practice in the locality in the past ten (10) years favors one craft. In that case, the Umpire shall base any decision on the prevailing practice in the locality. Except that if the Umpire finds that a craft has improperly obtained the prevailing practice in the locality through raiding, the undercutting of wages or by the use of vertical agreements, the Umpire shall rely on the decision of record and established trade practice in the industry rather than the prevailing practice in the locality;

c. Only if none of the above criteria is found to exist, the Umpire shall then consider that because efficiency, cost or continuity and good management are essential to the well being of the industry, the interests of the consumer or the past practices of the employer shall not be ignored;

d. The Umpire shall set forth the basis for their decision and shall explain their findings regarding the applicability of the above criteria. If lower-ranked criteria are relied upon, the Umpire shall explain why the higher-ranked criteria were not deemed applicable.

11. The Umpire is not authorized to award back pay or any damages for a misassignment of work, nor may any party to this procedure bring an independent action for back pay or any other damages, based upon a decision of the Umpire.

12. The fees and expenses of the Umpire shall be the responsibility of the non-prevailing party or parties to the arbitration.

13. The Employer shall not be subject to disputes regarding work assignments made by its subcontractors. However, the Employer must ensure that its subcontractors are signatory to the NMA(s) and are performing work under the terms and conditions of the NMA(s), and are following the procedures of this Article.

14. The Employer recognizes the Union herein as duly constituted for the purpose of bargaining collectively and administering this Agreement for the members affiliated with (CRAFT NAME).

ARTICLE II – UNION SECURITY

1. All employees covered by this Agreement and members of the Union now in the employ of the Employer shall remain members in good standing in the Union during the term of this Agreement.

2. All employees hired by the Employer shall, as a condition of employment, become and remain members in good standing of the Union within eight (8) days following the date of their employment.

3. Any employee, who is a member in good standing of any signatory International Union, shall be considered in compliance with the Union Security Article in this contract, so long as the employee maintains good standing in the Union.

4. In nuclear facilities it is agreed that applicants referred to the project under this Article shall be considered probationary employees until such time as they meet the owners' security requirements not inconsistent with State and Federal laws.

5. This provision shall not preclude such probationary employees' rights under Article VI relative to any grievance arising under any other section of this Agreement.

ARTICLE III – NONDISCRIMINATION

1. The Union and the Employer agree to comply with all applicable Federal and State equal employment opportunity and nondiscrimination in employment laws.

ARTICLE IV – SCOPE OF WORK

1. This Agreement covers all work assigned by the Owner to the Employer and performed by the employees of the Employer covered by this Agreement.

2. This Agreement does not cover work performed by the Employer of a new construction nature, in which event said work shall be done in accordance with existing building construction agreements.

3. The Union and the Employer understand that the Owner may choose to perform, directly subcontract, or purchase any part or parts of the work necessary on the project with due consideration given to achieving the highest standards and harmonious working conditions herein.

4. It is the intent of the parties that in-plant employees of the Owner will not be assigned to work directly with building and construction trades employees of the signatory Employer on the portion of the work assigned to the signatory Employer by the Owner. However, Paragraph 4 does not preclude in-plant employees of the Owner from performing work that has not been assigned to the signatory Employer while the building and construction trades employees of the Employer are present and working.

5. This Agreement shall have application only to the work location agreed upon between the Employer and the Union.

ARTICLE V – SUBCONTRACTING

1. All subcontracting of work at any tier covered by this Agreement shall be performed under this Agreement, other NMA(s), or any agreement approved as compatible by the NMAPC.

2. By becoming signatory to this Agreement the Employer acknowledges and agrees that any Union signatory to an NMA may bring a grievance under Article VI to enforce this subcontracting provision, and that monetary damages for lost wages and fringe benefits may be awarded for failure to subcontract work to Employers signatory to this Agreement, other NMA(s), or any agreement approved as compatible by the NMAPC.

ARTICLE VI – GRIEVANCES

1. Except for jurisdictional disputes and those involving general wage rates, all disputes and grievances arising out of work performed under this Agreement involving the meaning or interpretation of any provision in this Agreement, or involving the meaning or interpretation of any provision in any other agreement incorporated by reference in this Agreement shall be resolved in the following manner:

> a. All grievances shall be filed within ten (10) calendar days after the complained of event arose. Grievances shall be appealed to steps two (2) and three (3) within ten (10) calendar days after the meeting in the lower step. Settlement of grievances may be made at any step of the grievance procedure and shall be final and binding on the Union and Employer.

Step 1. Between the Employer's Supervisor and the Local Union Steward at the job site.

Step 2. Between the Business Representative and the Employer's Supervisor at the job site.

Step 3. Between the International Union Representative and the Supervisor or Labor Relations Manager.

Step 4. If the parties are unable to settle or resolve any grievance or controversy, the matter shall be submitted to the NMAPC for a decision to become effective immediately (parties should refer to NMAPC Grievance Procedures as amended June 17, 2011 at this step).

Step 5. Failure of the NMAPC to reach a decision shall constitute a basis for a submittal of the question by the affected parties to the American Arbitration Association for a binding decision. In such instances, the affected parties to the dispute shall appoint an arbitrator to review the matter and render a binding decision. If the parties are unable to agree upon an arbitrator, the American Arbitration Association shall appoint one. The affected parties to the arbitration shall equally share in the costs, including printing and publication of any record of such arbitration.

> b. The Arbitrator shall only have jurisdiction and authority to interpret, apply or determine compliance with the provisions of this Agreement. Any award of the Arbitrator shall be final and binding upon the Employer and the Union. The Arbitrator shall submit a copy of the award to the NMAPC after the award is rendered.

ARTICLE VII – UNION REPRESENTATIVE

1. A Steward shall be a qualified craftsperson appointed by the Business Agent and confirmed in writing to the Employer. The Steward shall be the last employee to be laid off, provided the Steward is qualified to perform the remaining work to be done at the job. The Steward shall not be terminated or laid off, except as the last employee, without prior notice to the Union.

2. Union representatives shall have reasonable access to jobs operated within the plant locations subject to Employer and Owner regulations.

ARTICLE VIII – WAGES

1. Wage rates shall be those as set forth in the current Labor Agreement of the affiliated Local Union where such work is to be performed and shall be paid to all employees under the terms of this Agreement. Unless otherwise modified by the NMAPC, wages shall be paid weekly by check or other legal tender.

2. When zone type wage structures are provided for in local agreements and are otherwise applicable in the area of the project, the project for the purposes of this Agreement will be considered as if it was within the area of the base zone rate.

ARTICLE IX – BENEFITS AND OTHER MONETARY FUNDS

1. Welfare Funds, Pension Funds, Apprentice Training Funds and other monetary funds required by the Local Union or District Council Labor Agreement shall be paid in accordance with the Local Labor Agreement, except that no funds shall be paid that exceed the straight time and overtime provisions of this Agreement.

2. The Employer agrees to be bound by and will sign all legally constituted trusts which have been established between Local Unions of the (CRAFT NAME) and recognized bargaining agencies of contractors in the area.

3. Industry Advancement or Promotion Funds required by the Local Labor Agreement may be paid at the discretion of the Employer. However, if approved by the NMAPC, these funds must be paid in accordance with the Local Labor Agreement.

4. Once an Employer is legally notified that it is delinquent in its contributions to the fringe benefit funds, apprenticeship fund, dues check off or any other contractually required contribution, and does not respond positively by forwarding said contributions to the appropriate place of receipt within three (3) business days, the provisions of Article XXII shall not apply and the Union may legally withhold services. However, it is understood that such action, consistent with Article XXII, does not allow said craft to establish any picket line.

5. An Employer who has been properly notified of delinquent benefit funds will not be allowed to submit any NMA site extension requests until all obligations are current.

ARTICLE X – COMPENSATION INSURANCE

1. For all employees covered by this Agreement, the Employer shall provide Workers' Compensation Insurance, Social Security and other protective insurance as may be required by law, and also furnish satisfactory proof of such to the Union.

2. In an effort to enhance the competitive position of the Employer and to provide greater work opportunities for members of the Union, the Employer and Local Unions are encouraged to negotiate and implement alternative dispute resolution procedures to resolve workers' compensation claims disputes when and where permissible and/or legal. Such alternative dispute resolution procedures when implemented will be final and binding on the parties and shall be made a part of the Agreement to the extent permitted by law.

ARTICLE XI – HOLIDAYS

1. For purposes of uniformity, the following Holidays shall be observed and, if worked, shall be paid at the rate applicable in the appropriate local agreement not to exceed double time:

New Year's Day
Presidents' Day (Federal)*
Memorial Day
Independence Day
Labor Day
Thanksgiving Day
Christmas Day

2. If any of these listed Holidays fall on Sunday, the following Monday shall be observed as the Holiday. If any of the listed Holidays fall on Saturday, the preceding Friday shall be observed as the Holiday.

3. *Presidents' Day (Federal) may be considered a floating Holiday and may be celebrated on an alternate day. Should the Building Trades Council that encompasses the geographical jurisdiction of where work is being performed under this Agreement, desire to celebrate Presidents' Day on an alternate work day, authorization must be obtained in writing from the NMAPC office.

ARTICLE XII – MINIMUM PAY / REPORTING TIME AND CALL-INS

1. An employee who reports for work at the regular starting time and for whom no work is provided shall receive pay equivalent to two (2) hours at the applicable hourly rate, provided the employee at the Employer's discretion remains available for work. Any employee who reports for work and for whom work is provided shall be paid for actual time worked but not less than two (2) hours. If the Employer considers it necessary to shut down work to avoid endangering the life or the safety of its employees the Employer will not be

in violation of this Agreement. In such cases, employees will be compensated only for the actual time worked. In the case of a situation described above where the Employer requests employees to remain available for work, the employees will be compensated for such time. If a project is shutdown because of weather, employees who reported to work shall be paid actual time worked but not less than two (2) hours. Procedures for prior notification of work cancellation shall be determined at the pre-job conference. The provisions of this Section are not applicable where the employee voluntarily quits, or is laid off, or is out by reason of a strike.

2. A call-in, which is defined as the notification to an employee to report for work by whatever means for work outside of his/her regular shift or on his/her regularly scheduled day(s) off or Holiday, shall be paid in accordance with one of the following methods:

a. A call-in prior to and continuous with an employee's normally scheduled shift shall be paid for on the basis of hours actually worked prior to the scheduled shift, at the applicable overtime rate;

b. When an employee is called in to work at or after the established starting time on Saturday, Sunday, scheduled day off or Holiday, the employee shall be paid not less than four (4) hours at the applicable overtime rate for that day, except when his/her call-in is prior to and continuous with the normal work hours.

c. Any call-in not continuous with the employee's regular work shift, will be paid a minimum of four (4) hours at the applicable overtime rate.

ARTICLE XIII – SUPERVISION

1. The designation, appointment and determination of the number of foremen and/or general foremen is the sole responsibility of the Employer. There is a requirement for initial supervision. However, the Employer shall not be unreasonably burdened with additional demands for supervision.

2. When established for a craft, one (1) top hourly craft-supervisor (foreman and/or general foreman) shall be guaranteed forty (40) straight-time hours per week. The forty (40) straight-time hour guarantee applies to straight-time hours, and the accumulation of overtime hours may not be considered for the purpose of applying those overtime hours to the "guaranteed forty (40) hours" provision. The forty (40) straight-time hour guarantee provision shall apply on a per Employer, per craft, per shift basis. It is understood that the individuals receiving such guarantee may, at the discretion of the Employer, be required to remain on the job.

3. Such guarantee shall not apply when the first or commencing week of a job is less than forty (40) hours, or when the top hourly craft supervisor is terminated due to reduction in force or job completion.

ARTICLE XIV – TRAVEL AND SUBSISTENCE

1. No subsistence, travel allowance, mileage or pay for travel time is required to be paid to any employee covered by the terms of this Agreement.

ARTICLE XV – WORK HOURS PER DAY

1. Eight (8) hours per day shall constitute a day's work and forty (40) hours per week, Monday to Friday, inclusive, shall constitute a week's work. The regular starting time shall be eight (8:00) A.M., and the regular quitting time shall be four-thirty (4:30) P.M.; lunch time shall be twelve (12:00) noon to twelve-thirty (12:30) P.M.

2. When shifts are required, the first (1st) shift shall work eight (8) hours at the regular straight-time rate. The second (2nd) shift shall work eight (8) hours at the regular straight-time rate, plus a $2.00 per hour shift additive. The third shift shall work eight (8) hours at the regular straight-time rate, plus a $2.25 per hour shift additive. A thirty (30) minute lunch period shall be mutually agreed upon by the Job Superintendent and the Union Representative and shall not be considered as time worked.

3. All time worked before and after the established work day of eight (8) hours, Monday through Friday, shall be paid at the appropriate overtime rate. All work commencing with the beginning of the established work day on Saturday shall be paid at the rate of time and one-half (1 ½). All work commencing with the beginning of the established work day on Sundays and/or Holidays shall be paid at the rate applicable in the appropriate local agreement, not to exceed double-time.

4. By mutual consent of the Employer and the Union, the starting and quitting times of any shift, including day work, may be changed for all or any portion of a particular job. For the purpose of this Article, the standard work day of eight (8) hours for the job or portion thereof to which any such change of starting time applies shall begin with such agreed starting time.

5. Employees shall be at their posts prepared to start work at the regular starting time.

6. Local labor agreement provisions regarding minimum number of days to establish shifts or shift starts are waived for work performed under this Agreement.

7a. The Employer may establish a four (4) day, ten (10) hour shift exclusive of the thirty (30) minute unpaid lunch period at the straight-time rate. The starting time shall be between 7:00 A.M. and 8:00 A.M. Forty (40) hours per week shall constitute a week's work Monday through Thursday. In the event a job is down due to weather conditions, Holiday or other conditions beyond the control of the Employer, then Friday may, at the option of the Employer, be worked as a makeup day at the straight-time rate. If Friday is scheduled as a makeup day a minimum of eight (8) hours will be scheduled and worked, weather permitting. Straight-time is not to exceed ten (10) hours a day or forty (40) hours per week. Starting time will be designated by the Employer; the Union will be advised of the starting time.

7b. The Employer may establish two (2) - four (4) day, ten (10) hour shifts at the straight-time rate Monday through Thursday. These shifts are exclusive of the thirty (30) minute unpaid lunch period. The day shift shall work four (4) days at ten (10) hours per day at the regular straight-time rate. The second shift shall work four (4) days at ten (10) hours per day at the regular straight-time rate, plus a $2.00 per hour shift additive. In the event the job is down due to weather conditions, or a Holiday or other conditions beyond the control of the Employer, then Friday may, at the option of the Employer, be worked as a makeup day at the straight-time rate. Straight-time is not to exceed ten (10) hours a day or forty (40) hours per week.

7c. Employees who inform their Employer on Thursday that they do not wish to work Friday as a make-up day will not be penalized.

7d. An employee who is referred for employment and is scheduled for less than forty (40) hours of work (from the date of hire to date of termination), shall receive overtime pay for all hours worked in excess of eight (8) hours per day.

8. Since it is recognized that the standard work week may not be appropriate or cost effective for some projects, other arrangements for hours of work can be considered. The Employer may establish flexible work schedules such as a staggered work week and the like, by submitting its request to the NMAPC for approval as stipulated in Article XVIII. Prior to reaching a decision, the NMAPC shall take into consideration the project schedule, the manpower requirements, the geographic location of the project, the Owner's work schedule and other appropriate factors. Such approval will be incorporated as an addendum to this Agreement for that specific site.

ARTICLE XVI – TRANSPORTATION

1. At plant locations where private transportation is not permitted, the Employer shall furnish transportation that provides shelter from inclement weather from the gate to the job site and back to the gate when said distance is one-half (½) mile or more one way. When transportation is required, the Employer shall transport the employees, no later than 10 minutes after the end of the shift, to the point where such employees were picked up. When employees are transported to the pickup point later than 10 minutes after the shift, then overtime pay shall apply as provided under Article XV.

ARTICLE XVII – SAFETY

1. The employees covered by the terms of this Agreement shall at all times while in the employ of the Employer be bound by the safety rules and regulations as established by the Owner, the Employer, this Agreement, or applicable Safety Laws.

2. The parties to this Agreement do hereby recognize the need to provide a drug-free and alcohol-free workplace. The parties to the Agreement agree to comply with any mandated substance abuse program. In order to produce as safe a workplace as possible, it is un-

derstood and agreed that the Employer and the employees shall abide by the rules and provisions of the implemented substance abuse program, which may include the following types of testing: pre-employment, reasonable suspicion, post-incident, and random where allowed by law. Any discriminatory practice under this Article shall be subject to the NMAPC Grievance Procedure. All substance abuse programs shall be submitted to the NMAPC for distribution prior to implementation.

ARTICLE XVIII – APPRENTICES

1. The Union acknowledges that different apprentice ratios than those established may be needed to cover plant maintenance. Therefore, the Employer and the Union agree that existing ratios will be utilized but that higher ratios may be negotiated when warranted by conditions. Further, an Employer may employ pre-apprentice classifications for work customarily performed by the craft, provided pre-apprentice classifications are recognized in the Local Labor Agreement.

ARTICLE XIX – HIRING AND TRANSFER OF CRAFT WORKERS

1. The Employer agrees to hire Craft Workers in the area where work is being performed or is to be performed in accordance with the hiring procedure existing in the area; however, in the event the Local Union is unable to fill the request of the Employer for employees within a forty-eight (48) hour period after such request for employees (Saturdays, Sundays and Holidays excepted), the Employer may employ workers from any source. The Employer shall have the right to move qualified employees from one job assignment to another within the plant location where they are working.

2. The Employer shall determine the competency of all employees. The Employer shall determine the number of employees required on the project and shall select any employee or employees working under the terms of this Agreement to be laid off regardless of membership or non-membership in the Union.

ARTICLE XX – GENERAL SAVINGS CLAUSE

1. Any provisions in this Agreement which are in contravention of any Federal, State, Local or County regulations or laws affecting all or part of the limits covered by this Agreement shall be suspended in operation within the limits to which such laws or regulations are in effect. Such suspension shall not affect the operation of any such provisions covered by this Agreement to which the law or regulation is not applicable, nor shall it affect the operations of the remainder of the provisions of the Agreement within the limits to which such law or regulation is applicable.

ARTICLE XXI – CREW SIZE

1. The crew size shall be any number of craftspersons and supervision required to safely perform the work and shall be increased or decreased at the discretion of the Employer.

ARTICLE XXII – LOCKOUT AND WORK STOPPAGE

1. During the term of this Agreement, there shall be no lockouts by the Employer and no strikes, picketing, work stoppages, slow downs or other disruptive activity for any reason by the Union or by any employee. Failure of the Union, its Local Union or employee to cross any picket line at the Employer's project site is a violation of this Article.

2. In the event that a local or area collective bargaining agreement expires and a subsequent work stoppage ensues, the Employer and its employees will continue to work since the intent of this provision is to allow maintenance work to continue as a benefit to the client. The wages and fringe benefits in the expired local collective bargaining agreement or as approved by the NMAPC will remain in effect for all work covered under the terms of this Agreement until wages and fringe benefits are agreed upon and become effective for the recognized bargaining agency of the local contractors and the affected Union.

3. Sections 1 and 2 of this Article shall not apply if the Employer signatory to this Agreement is a member of the current local negotiating committee or if said signatory Employer actively participates in local negotiations. In such cases, when a local collective bargaining agreement expires, the affected Union may withhold services from said Employer, but shall not interrupt the work of other crafts. Moreover, said Employer shall have the right to request in writing to the appropriate International Union that Section 3 of this Article be waived in order to allow the Employer to participate in local negotiations. The International Union has the sole discretion to grant such waiver and will communicate its decision in writing both to the Employer and affected Owner(s).

4. The International Union and its applicable Local Union shall not sanction, aid or abet, encourage or continue any work stoppage, strike, picketing or other disruptive activity which violates this Article and shall undertake all reasonable means to prevent or to terminate any such activity. No employee shall engage in activity which violates this Article. Any employee who participates in or encourages any activity which violates this Article shall be subject to disciplinary action, including discharge, and if justifiably discharged for the above reasons, shall not be eligible for rehire on the same project for a period of not less than ninety (90) days. Further, if the Union(s) are unable to provide qualified replacements for those employees who are in violation of this Article by the beginning of the next shift, the Employer is free to hire from any source.

5. Neither the International Union nor its Local Union shall be liable for acts of employees for which it has no responsibility. The International Union will immediately instruct, order and use its best efforts to cause its Local Union to cease any violation of this Article. If it complies with this obligation, the International Union shall not be liable for unauthorized acts of its Local Union. The principal officers of the Local Union will immediately instruct, order and use their best efforts to cause the employees of the Local Union they represent to cease any violation of this Article. If it complies with this obligation, the Local Union shall not be responsible for unauthorized acts of employees it represents.

6. In the event of any work stoppage, strike, picketing or other disruptive activity in violation of this Article, the Employer, at its discretion and without penalty, may suspend all or any portion of the project work affected by such activity.

7. Any signatory International Union or affiliated Local Union which initiates, participates in, or supports a work stoppage, strike, picketing or other disruptive activity in violation of this Article agrees to pay liquidated damages as a remedy for said violation, in accordance with Section 8h. of this Article.

8. After all parties and the NMAPC have been notified of an alleged violation, a party or the NMAPC may institute the following procedure, in lieu of, or in addition to, any other action at law or equity.

8a. To invoke the procedure, a party or the NMAPC shall notify the permanent Arbitrator under this procedure through the NMAPC Impartial Secretary/CEO. Notice to the Arbitrator, through the NMAPC Impartial Secretary/CEO, shall be by mail, FAX, and/or e-mail with copies of the notice to be sent to the other parties.

8b. Upon receipt of said notice the Arbitrator shall schedule and hold a hearing within twenty-four (24) hours, provided the invoking party contends that the violation still exists.

8c. The Arbitrator shall notify the parties by mail, FAX, and/or e-mail of the hearing's location. The hearing shall be completed in one session. A failure of any party to attend the hearing shall not delay the admittance of evidence or issuance of an award by the Arbitrator.

8d. The sole issue at the hearing shall be whether or not a violation of this Article has in fact occurred. The Arbitrator's award shall be issued in writing within three (3) hours after the close of the hearing, and may be issued without an opinion. If any party desires an opinion, one shall be issued within fifteen (15) days, but its issuance shall not delay compliance with, or enforcement of, the award. The Arbitrator may order cessation of the violation of this Article, and such award shall be served on all parties by hand delivery, mail, FAX, and/or e-mail.

8e. The Arbitrator's award may be enforced in the following manner by any court of competent jurisdiction upon the filing of this Agreement and all other relevant documents referred to hereinabove. Mailed, FAXED, and/or e-mailed notice of the filing of such enforcement proceedings shall be given to all parties. In a proceeding to obtain a temporary order enforcing the award, all parties agree to waive the right to a hearing and agree that such proceedings may be exparte. Such agreement, however, does not waive any party's right to participate in a hearing for a final order of enforcement. The court's order enforcing the award shall be served on all parties by hand, by delivery to their last known addresses or by registered mail.

8f. Any rights created by statute or law governing arbitration proceedings that are inconsistent with the above procedure or that interfere with compliance herewith are waived.

8g. The fees and expenses of the Arbitrator shall be paid by the party or parties found in violation of this Article. In the event no violation of this Article is found, such fees and expenses shall be paid by the invoking party.

8h. If the Arbitrator determines in accordance with Section 8d. above that the International Union and/or its local union has violated this Article, the International Union and/or its local union shall direct all of the employees they represent at the project to immediately return to work within eight (8) hours of receipt of the award. If the employees do not return to work by the beginning of the next regularly scheduled shift following receipt of the Arbitrator's award, and the International Union and/or its Local Union have not complied with Section 5 above, the Union and/or the Local Union shall pay the sum of ten thousand dollars ($10,000.00) as liquidated damages to the affected owner, and shall pay an additional ten thousand dollars ($10,000.00) per shift for each shift thereafter on which the employees have not returned to work. The Arbitrator shall retain jurisdiction to determine compliance with this section and Section 5.

8i. If the Arbitrator determines in accordance with Section 8d. above that the Employer has engaged in an illegal lockout in violation of this Article, the Employer shall notify the International Union that the illegal lockout has ended within eight (8) hours of receipt of the award. If the illegal lockout is not ended by the beginning of the next regularly scheduled shift following receipt of the Arbitrator's award, then the Employer shall pay the sum of ten thousand dollars ($10,000.00) as liquidated damages to the International Union, and shall pay an additional ten thousand dollars ($10,000.00) per shift for each shift thereafter on which the Employer continues to illegally lockout its employees covered by this Agreement. The Arbitrator shall retain jurisdiction to determine compliance with this section.

9. The procedures contained in Section 8 through 8i shall be applicable to alleged violations of this Article. Disputes alleging violation of any other provision of the Agreement, including any underlying dispute alleged to be in justification, explanation or mitigation of any violation of this Article, shall be resolved under the grievance adjudication procedures of Article VI.

ARTICLE XXIII – MANAGEMENT CLAUSE

1. In the exercise of its functions of management, the Employer shall have the right to plan, direct and control the operation of all its work; hire employees and supervision; direct the working forces; assign employees and supervision to their jobs; refuse any applicant; discharge, suspend or discipline for proper cause; transfer, promote or demote employees and supervision; lay off employees and supervision because of lack of work or for other legitimate reasons; require employees and supervision to observe the Employer's rules and regulations not inconsistent with this Agreement; regulate the use of all equipment and other property of the Employer; decide the amount of equipment to be used; the number of employees needed; and contract work anywhere and decide the methods of work and the source from which material and equipment is obtained. The Employer shall not use these rights for the purpose of discrimination against any employee. These provisions do not prohibit the Union's right to the peaceful exercise of Article VI above if in its judgment the spirit and intent of this Agreement has been violated.

ARTICLE XXIV – PARTNERING

1. As manifested in the Mission Statement, the NMAPC Program is based on its continual commitment to improve the partnering and communication between Owners, union Contractors, and building trades Craft Workers. To further the goal of better dialogue and expedited problem solving, the NMAPC Program encourages the development of local tripartite committees for a specific project or area, that are empowered to establish lines of communication, seek solutions to unique job site needs, and suggest methods and ways to continuously improve safety, productivity, and quality.

2. The initial establishment of a local committee may be implemented through the NMAPC office. The NMAPC office will provide the framework and oversight for effective partnering to enhance safety, productivity and quality.

ARTICLE XXV – WELDING CERTIFICATION

1. The Union and the Employer agree to arrange the pretesting of welders at a mutually agreeable time and place. Such testing will be done without compensation, except that welders passing a certification test will be compensated for actual time required to take such test, not to exceed four (4) hours pay upon the employee's first employment with that Contractor. However, in order to receive said compensation, the employee must remain at work on the job at least five (5) working days, or in the case of jobs of less than five (5) working days, for the duration thereof.

2. In instances where a participating International Union is party to a program to provide welder certification and/or maintenance of welder certification records with objectives equal to this Article, then such program will be applicable under this Agreement.

ARTICLE XXVI – REPORTING REQUIREMENTS ADMINISTRATIVE FEES

1. All Employers signatory to this Agreement shall report all work hours performed under this Agreement on a quarterly basis or at such times as deemed necessary by the NMAPC. The report shall include the sum total of work hours performed by each craft at each location for each quarterly reporting period. Each location shall be reported separately on the NMAPC website at www.nmapc.org. Hard copies of the forms will be furnished by the NMAPC only upon request.

2. The Employer shall remit an annual administrative fee in such an amount deemed necessary by the NMAPC to defray the costs of administering and operating the NMAPC Program. Administrative fees shall be payable in accordance with the terms stipulated on the NMAPC Administrative Fee Invoice. Administrative fees may be remitted via the NMAPC website at www.nmapc.org.

3. As a party to this Agreement and participant in the NMAPC Program, the Employer acknowledges its obligation to remit the annual administrative fee to the NMAPC. Administrative Fees that remain outstanding will continue to accrue a late fee on each late notice.

In the event the Employer fails to remit such fees after demand for timely payment, the Employer consents to the jurisdiction of the courts of the Commonwealth of Virginia in any action brought by the NMAPC to collect the fee. The Employer further agrees that it will be liable and responsible for any costs of collection, including reasonable attorney fees and court costs, incurred in such action by the NMAPC.

ARTICLE XXVII – ADMINISTRATIVE PROCEDURE

1. Extensions of this Agreement shall be on a location by location basis and shall be sought for each location. Employers awarding work to a subcontractor must ensure that the subcontractor has applied for the NMA(s) and is in possession of them with permission to use them at the time of award, through the inspection of a valid site extension approval(s). Pre-job conferences shall be required for all work performed under this Agreement as stipulated in Article I.

2. The Employer must file site extension requests via the NMAPC website at www.nmapc.org for the location(s) where the work will be performed. The Employer must be current in the remittance of all administrative fees and fringe benefit contributions in order to obtain or utilize a valid site extension.

3. This Agreement is between the Employer and the International Union only and is binding upon its affiliated local unions and district councils. The International Union is responsible for acting on all site extension requests in a timely manner. The NMAPC is the only intermediary or administrative body for this Agreement and the policy decisions contained in the NMAPC Book of Decisions, which are part of this Agreement. Revisions to this Agreement shall be made only by majority vote of the NMAPC.

4. This Agreement is a stand alone agreement and none of the provisions in any local, regional, area or national collective bargaining agreement shall apply, unless specifically incorporated in this Agreement. Furthermore, this Agreement is the exclusive collective bargaining agreement for any work to which it is extended, and for such work it supersedes and overrides the terms and conditions of any and all other national, area, or local collective bargaining agreements to which the parties hereto, or either of them may be signatory.

ARTICLE XXVIII – ADDENDA TO NATIONAL MAINTENANCE AGREEMENT

1. Addenda to this Agreement which are required to place the Employer in a more competitive position or address the Owner's requirements may be established by majority agreement of the signatory International Unions comprising the NMAPC. Such addenda shall be reduced to writing and shall be attached hereto and made part of this Agreement for that project.

2. The Employer or Owner shall submit its request in writing to the NMAPC outlining the various site requirements that necessitate such approval.

ARTICLE XXIX – DURATION OF AGREEMENT

SAMPLE

1. This Agreement becomes effective _____, 20_____, and shall continue in effect unless terminated by no less than ninety (90) days' notice to the other party, in writing or on the NMAPC website at www.nmapc.org. Changes may be made at any time by mutual consent.

2. The parties agree to revisions to this Agreement which are formally approved by the National Maintenance Agreements Policy Committee, Inc., and of which they are notified in writing by the Committee.

FOR THE *CRAFT NAME*:

SAMPLE

_____
General President

FOR THE EMPLOYER:

SAMPLE

_____
Company Name

_____
Street Address

_____
City State Zip

_____
Phone Number

_____
FAX Number

_____
Name and Title (Printed)

_____
Name and Title

NMAPC
NATIONAL MAINTENANCE AGREEMENTS POLICY COMMITTEE, INC.

1501 LEE HIGHWAY, SUITE 202 • ARLINGTON, VA 22209-1145
TELEPHONE: (703) 841-9707 • FAX: (703) 524-3364
www.nmapc.org

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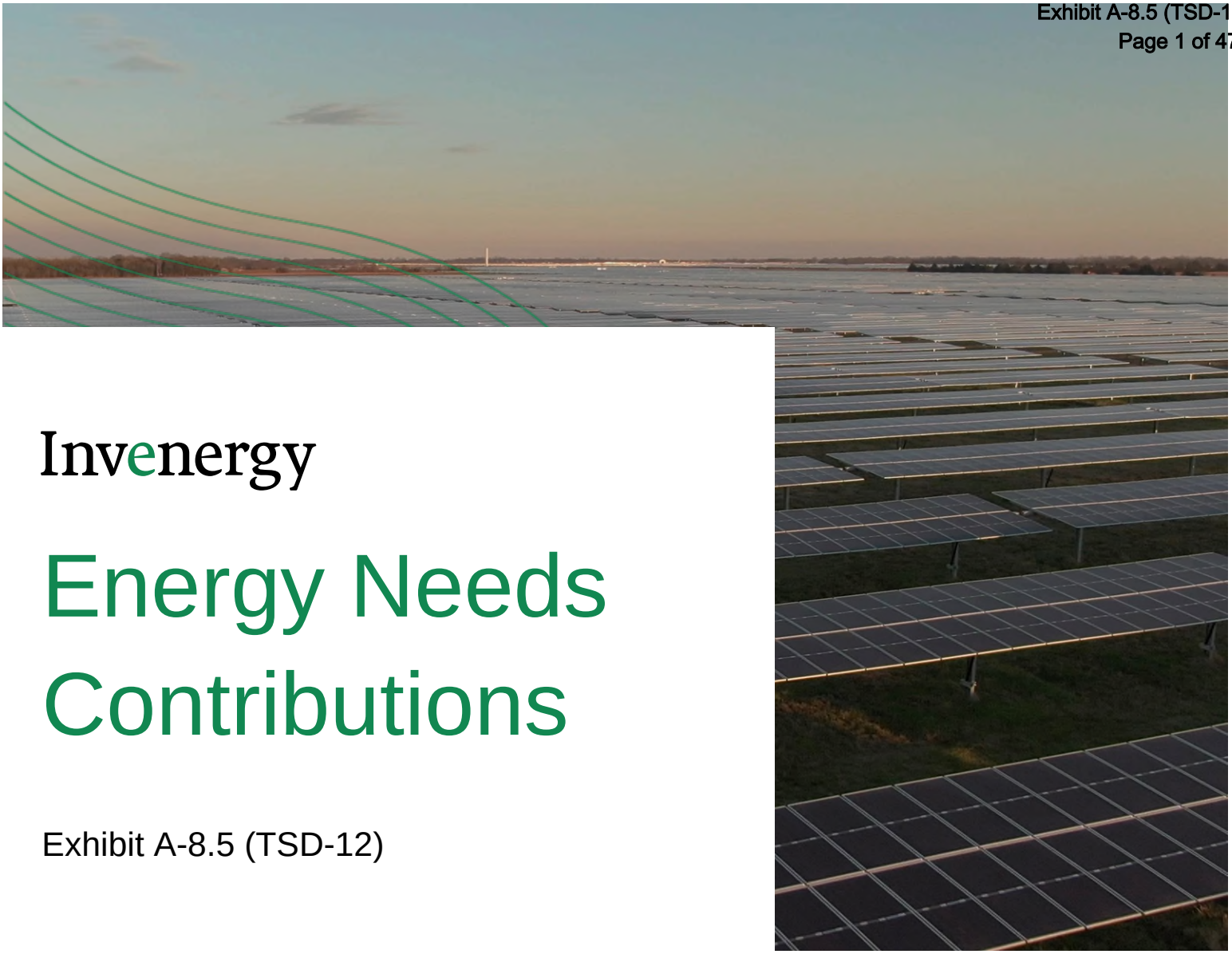

Invenergy

Energy Needs Contributions

Exhibit A-8.5 (TSD-12)

PREPARED FOR:

WASHTENAW SOLAR ENERGY LLC

Invenergy

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1.0 Introduction

Washtenaw Solar Energy LLC ("Washtenaw Solar") is proposing a 150 MW solar energy facility in Saline Township, Washtenaw County, Michigan (the "Project"). The Project is consistent with Michigan's identified energy, capacity, reliability, and resource adequacy needs. There is a demonstrated need for the Project and the Project will benefit the public by meeting those needs.

2.0 Identified Energy Needs

In Executive Directive 2020-10, Michigan Governor Gretchen Whitmer directed the Department of Environment, Great Lakes, and Energy through the Office of Climate and Energy, to develop and issue the MI Healthy Climate Plan (the "Plan") to serve as Michigan's action plan to reduce greenhouse gas emissions and transition toward economy-wide carbon neutrality. The Plan is included as **Appendix A.**

The Plan is a state policy document that identifies action items to help achieve Governor Whitmer's goal of economy-wide carbon neutrality no later than 2050. Plan, p 7. One such action item is to increase the adoption of solar generation. Plan, p 33.

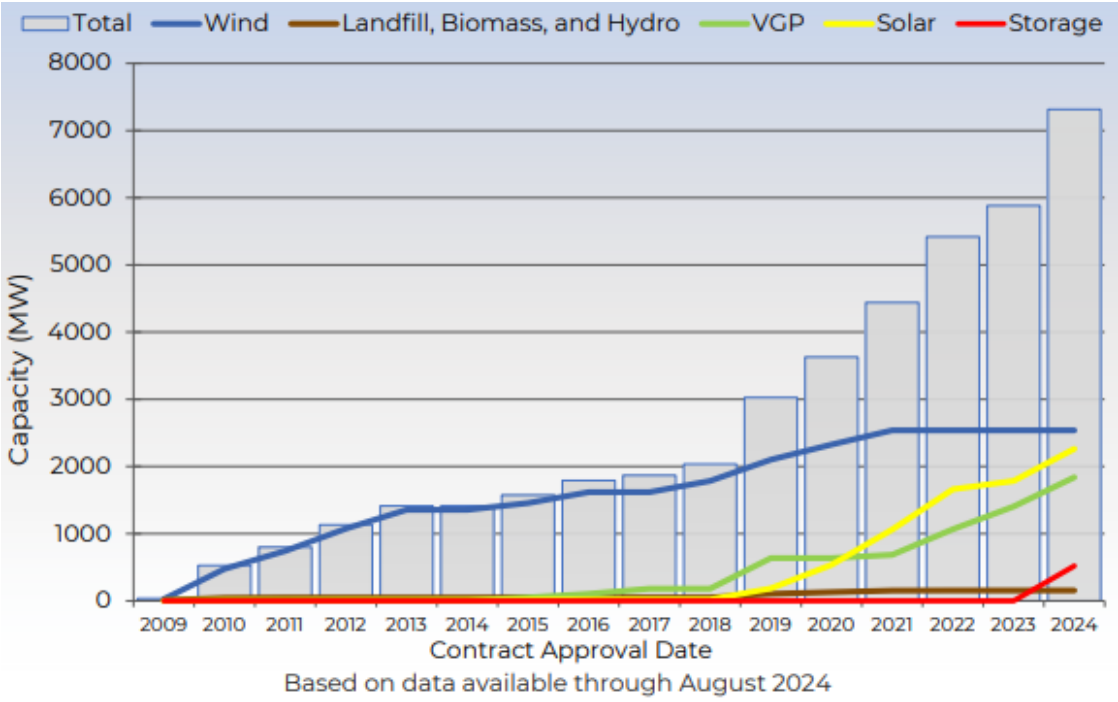
In 2023, Michigan's clean energy standards were amended under Public Act 235 of 2023 ("PA 235"). Under PA 235, Michigan's clean energy targets were increased to 80% by 2035 and 100% by 2040. Facilities such as the Project are critical to accomplishing these targets through the construction of utility-scale renewable facilities to replace energy now produced by fossil fuels.

3.0 Identified Capacity Needs

The Project is projected to have a nameplate capacity value of 150 MW. Because the Project's electric generating capability depends on the availability of the sun, its full capacity cannot be relied upon to meet the state's electric capacity needs. The Midcontinent Independent System Operator ("MISO") initially sets the capacity value for solar at 50% for Summer, Fall and Spring and 5% for the Winter, and then sets the capacity value based on the Project's actual metered output.

The figure below shows anticipated capacity additions in Michigan based on Integrated Resource Plan ("IRP") projections currently approved by the Michigan Public Service Commission ("MPSC"). See MPSC Report, Status of Renewable Energy, Distributed Generation and Legacy Net Metering in Michigan (December 16, 2024), p 11, included as **Appendix B** ("MPSC Report"). The MPSC expects that Michigan will have over 8,000 MW of renewable energy capacity operating by the end of 2026. *Id.* The Project was included in that projection and has been identified as a resource that will help meet Michigan's capacity needs.

The results of MISO's Planning Resource Auction for Planning Year 2025/26 ("PRA Results") also observed that new capacity additions in the region have not kept pace with reduced accreditation values, suspensions/retirements, and reduced imports. See MISO, PRA Results (April 2025), included as **Appendix C**. The Project is important to meeting capacity needs in Michigan, within MISO's Local Resource Zone 7, and region wide.



4.0 Identified Reliability Needs

Prior to executing its Generator Interconnection Agreement ("GIA") with MISO and ITC*Transmission*, the Project underwent System Impact Studies as part of the MISO interconnection queue process. MISO's studies ensure that there will be no negative impacts on electrical reliability in Michigan as a result of the Project. With regard to reliability needs, the Project will require minor upgrades to ITC*Transmission*'s Majestic 345 kV station and will require no distribution upgrades. See **Exhibit A-12 (TSD-13)**. The Project will not create any reliability issues as a result of its interconnection to the electric grid. Through its GIA, Washtenaw Solar has committed to satisfying any financial commitments related to the reliability needs created by the Project.

5.0 Identified Resource Adequacy Needs

The Project has been identified as a renewable energy project that will help meet Consumers Energy's ("Consumers") resource adequacy needs. The Project is the subject of a Build Transfer Agreement ("BTA") executed with Consumers Energy and approved by the Commission.

5.1 The Consumers IRP (Case No. U-20165)

On June 15, 2018, Consumers filed the first IRP in Michigan under MCL 460.6t in Case No. U-20165. Consumers proposed, among other things, a fundamental shift in the resources which make up Consumers' capacity resource portfolio by laying the foundation for Consumers' procurement of approximately 6,000 MW of new solar resources by 2040. The acquisition of these new solar resources was a key component of the additional supply in Consumers' IRP Proposed Course of Action ("PCA"). In its Order Approving Settlement Agreement, the MPSC approved a Settlement Agreement which resolved all matters at issue in the Consumers' 2018 IRP. June 7, 2019 Order in Case No. U-20165, included as **Appendix D**.

In 2020, Consumers implemented a competitive solicitation which complied with the requirements of Consumers' approved IRP. The RFP sought to acquire up to 300 MW of additional aggregate nameplate capacity projects with commercial operation dates on or before May 31, 2023, all located in the state of Michigan's Lower Peninsula. Of the 300 MW solicited, Consumers sought to acquire 150 MW through long-term Power Purchase Agreements ("PPAs") and 150 MW through BTAs or Consumers-proposed projects. Consumers' process ultimately resulted in the selection of a 150 MW solar facility. The selection of the Washtenaw Solar BTA was consistent with the independent administrator process required under Michigan's IRP competitive solicitation process.

According to Consumers, the Washtenaw Solar BTA is expected to provide the following benefits to Consumers, Consumers' customers, and surrounding communities: (i) the Washtenaw Solar BTA supports desired additional capacity needed in accordance with the Company's IRP PCA; (ii) the Washtenaw Solar BTA was competitively bid, ensuring low cost, economic pricing in accordance with Consumers IRP Settlement Agreement; and (iii) Consumers will receive the renewable energy credits produced by the facility to support its Clean Energy Plan. The proposal for the Washtenaw Solar BTA passed due diligence review, and the Washtenaw Solar BTA with Consumers was executed, with an effective date of October 4, 2021. The MPSC approved the Washtenaw Solar BTA on November 18, 2021. November 18, 2021 Order in Case No. U-20165, included as **Appendix E**.

5.2 The Consumers Renewable Energy Plan (Case No. U-21816)

Under state law, Consumers must file a Renewable Energy Plan ("REP") with the MPSC that includes a "forecast of the renewable energy resources needed to comply with the renewable energy credit standard." MCL 460.1022(3). Accordingly, Consumers included the Project in its REP filing because it represents renewable energy resources that the Consumers is planning to use for compliance with Michigan's Renewable Energy Credit ("REC") Standard. See Consumers Amended REP Application (Excerpted) in Case No. U-21816, included as **Appendix F**. On September 11, 2025, the MPSC issued an order approving Consumers' Amended REP in part, with the inclusion of the Project. September 11, 2025 Order in Case No. U-21816, included as **Appendix G**.

6.0 Conclusion

The Project will have positive impact on the state with regard to identified energy, capacity, reliability and resource adequacy needs. For Michigan to meet its renewable energy goals, it will need to develop as many locations suitable for utility-scale development as possible. The Project has willing landowners with large lands suitable to develop a large solar resource, contains transmission infrastructure with adequate available capacity and has limited potential impacts on the environment and public health and welfare. The Project is needed to meet Michigan's energy goals as well as Consumers' renewable energy and resource adequacy goals.

Appendices

7.0 Appendices

Appendix A: MI Healthy Climate Plan

MI HEALTHY CLIMATE PLAN

EGLE MICHIGAN DEPARTMENT OF ENVIRONMENT, GREAT LAKES, AND ENERGY

APRIL 2022

MICHIGAN DEPARTMENT OF
ENVIRONMENT, GREAT LAKES, AND ENERGY

This report is available digitally at *Michigan.gov/EGLE*

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To request this material in an alternative format, contact EGLE-Accessiblity@Michigan.gov or call 800-662-9278.

LETTER FROM EGLE DIRECTOR

Dear fellow Michigan residents:

I am proud to present the MI Healthy Climate Plan, with thanks to Governor Gretchen Whitmer for trusting the Michigan Department of Environment, Great Lakes, and Energy to lead this work and deep appreciation for the hundreds of Michiganders who contributed to it over the past year through thousands of hours of research, reflection, and conversation.

This plan lays out a broad vision for fulfilling the governor's fall 2020 commitment for Michigan to achieve 100% economy-wide carbon neutrality by midcentury – the global science-based benchmark for reducing greenhouse gas emissions to avoid the most devastating and costly impacts of climate change.

As its name suggests, this is a uniquely Michigan plan. It was shaped by a multitude of Michiganders with varied perspectives on climate change. We heard from environmental justice, public transit, local food, and climate action advocates; an array of business and labor leaders; academic experts and local government officials; and concerned residents of all political persuasions and walks of life. I firmly believe conversation leads to better outcomes. In this case, it has produced a bold plan that a broad cross-section of Michiganders can rally around.

This Plan is also rooted in what makes our state special. No state is better positioned than Michigan to advance equity, create good-paying jobs, increase economic competitiveness, and improve quality of life in pursuing carbon neutrality – thanks to our unmatched freshwater resources and heritage as a global manufacturing innovator, diverse agricultural producer, world-class outdoor recreation hub, and home to talented people and vibrant communities.

Finally, the responsibility for implementing this Plan and refining it over time is ours. All 10 million of us have big parts to play in decarbonizing our economy – from the governor and state lawmakers who will make the necessary state policy changes and budgetary decisions to the workers, business leaders, and entrepreneurs who will turn cutting edge climate solutions into high-quality jobs and economic prosperity; the community leaders and advocates who will ensure this work reaches every corner of the state and benefits every Michigan family; and each of us as individuals and consumers who will take myriad actions in our daily lives.

It is essential that we act now to greatly accelerate the decarbonization of Michigan's economy, building on the recent progress Michigan has made thanks to our public and private sector leaders. While some solutions to achieve a 100% decarbonized economy that delivers good jobs and justice are still on the drawing board, most are well known to us and awaiting our commitment to getting the job done and equitably sharing the burdens and benefits.

Fortunately, we have the resources to demonstrate that commitment and kickstart progress. Governor Whitmer's 2023 state budget recommendation includes over $500,000,000 for climate, clean energy, and mobility initiatives. And the state is committed to fully leveraging the current dramatic influx of federal dollars to move Michigan closer to our decarbonization goals.

In other words, we have a commitment, a plan, and a financial platform. We have what we need, so let's get to work.

Liesl Eichler Clark, Director
Michigan Department of Environment, Great Lakes, and Energy

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EXECUTIVE SUMMARY

The real and costly impacts of the climate crisis are irrefutable and that was especially obvious on the ground in Michigan during 2021. Severe, climate-induced weather events over the summer caused more than one million Michiganders to lose power, some for a week or more. Southeast Michigan was hit by intense rain, causing widespread floods and sewer backups. All this came on the backend of a decade in which our state has experienced massive flooding and dam failures, high water levels and erosion that destroyed public and private property, major crop failures from erratic spring temperatures, and three polar vortexes that challenged Michigan families to keep the heat on.

Sadly, Michigan is not alone. We all remember Texas freezing over after unprecedented cold and ice storms in February 2021, taking lives, freezing pipes, and causing historic damage.

Meanwhile, California was ablaze, hit by twice as many wildfires as the previous record year. A “heat dome” that settled over the Pacific Northwest in late June broke the previous record temperature by more than 10 degrees.

Globally, the seven warmest years in recorded history have occurred since 2015, a trend the United Nations’ Intergovernmental Panel on Climate Change has called “a code red for humanity.”

If we do not act aggressively to reduce greenhouse gas (GHG) emissions, these changes will only intensify, and the impacts will become more challenging, dangerous, and expensive for Michigan residents. It is imperative that we reduce emissions as quickly as possible and simultaneously prepare for the changes we cannot prevent.

The good news is we have made progress in recent years in reducing our GHG emissions. In the process, we have learned that aggressive action on climate change presents a variety of significant opportunities to better the lives of all Michiganders, including offering immediate opportunities to **reduce costs** and create **good-paying jobs for working families**.

Governor Whitmer has taken bold action to dramatically accelerate Michigan's progress down that promising path, including committing Michigan to economy-wide carbon neutrality no later than 2050 with aggressive interim targets on the way to midcentury and net negative GHG emissions thereafter. To achieve these ambitious goals, she charged the Michigan Department of Environment, Great Lakes, and Energy's (EGLE) Office of Climate and Energy with developing the *MI Healthy Climate Plan* (Plan). (See *Introduction*)

MICHIGAN - one of only 14 states with bold economy-wide goals

- ✓ Reduce GHG emissions 28% below 2005 levels by 2025 and 52% by 2030
- ✓ Achieve economy-wide carbon neutrality by 2050
- ✓ Maintain net negative GHG emissions thereafter

Objectives

OBJECTIVES OF THE MI HEALTHY CLIMATE PLAN

The Plan strongly emphasizes environmental justice to ensure Michigan's climate strategies uplift every portion of the state, including individuals and communities that have borne the brunt of climate impacts and are at the greatest risk of being left behind in the transition ahead. It also spotlights decarbonization strategies that will yield significant health, economic, and other benefits. (See *Why Climate Action Matters for Michigan*).

The Plan is meant to identify what needs to happen for Michigan to reach carbon neutrality by 2050 with a prioritization on actions from now until 2030. It focuses most heavily on the areas where the biggest, most rapid gains in GHG reductions can be made – energy, transportation, and buildings. The Plan's full complement of recommendations are detailed in the *Roadmap to 2030* section . The following briefly summarizes the highlights across the six categories the Plan uses to group the climate actions needed to achieve our goals.

Commit to Environmental Justice and Pursue a Just Transition: Ensure that at least 40 percent of state funding for climate-related and water infrastructure initiatives benefit Michigan's disadvantaged communities (in line with the federal government's Justice40 guidelines for federal funding); that Justice40 is developed in partnership with leaders in disadvantaged communities; and that Michigan emphasizes a just transition for all workers through proactive engagement, job training, and workforce development.

Clean the Electric Grid: Generate 60 percent of the state's electricity from renewable resources and phase out remaining coal-fired power plants by 2030. Limit energy burden from powering and heating homes to not more than 6 percent of annual income for low-income households.

Electrify Vehicles and Increase Public Transit: Build the infrastructure necessary to support 2 million electric vehicles on Michigan roads by 2030. Increase access to clean transportation options – including public transit – by 15 percent each year.

Repair and Decarbonize Homes and Businesses: Reduce emissions related to heating Michigan homes and businesses by 17 percent by 2030. Increase investments in repairing and improving buildings to reduce costs for working families and small businesses.

Drive Clean Innovation in Industry: Encourage clean innovation hubs where private enterprises strategically co-locate and collaborate to develop and deploy new, cleaner manufacturing technologies and conduct research and development to reduce emissions from hard to decarbonize industries. Triple Michigan's recycling rate to 45 percent and cut food waste in half by 2030.

Protect Michigan's Land and Water: Protect 30 percent of Michigan's land and water by 2030 to naturally capture GHG emissions, maintain and improve access to recreational opportunities for all Michiganders, and protect biodiversity. Leverage innovative strategies to support climate-smart agriculture.

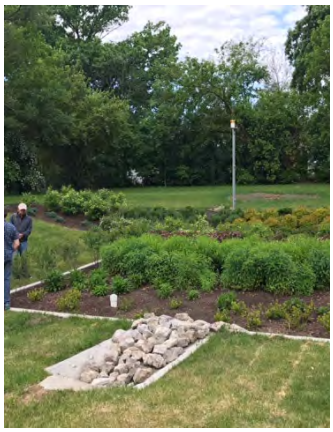
The Plan's comprehensive set of policy recommendations in these areas will help reduce GHG emissions at the scale and pace necessary to reach our interim goal of reducing GHG emissions 52% by 2030. However, they do not go far enough on their own. Additional policy changes and actions in every sector will be necessary to get all the way to that target. That is why we must continue to evaluate and update strategies (and this Plan) and seek new emissions-reduction pathways that will spur a self-reinforcing cycle and more fully unleash Michigan ingenuity.

Beyond 2030, the steps necessary to make Michigan's economy carbon neutral by 2050 are no less urgent. In many cases, the actions necessary to fully achieve this goal over the next 28 years will require substantial efforts in the sectors of our economy that are hardest to decarbonize, including industry, buildings and housing, and agriculture. The Plan takes a balanced approach to these issues, identifying the actions we can take today to make real progress between now and 2030, while also immediately digging into the hard work of identifying strategies to get us the rest of the way to carbon neutrality by 2050. To achieve our goals, we must also avoid actions between now and 2030 that make it more difficult to reach carbon neutrality.

It is also important to note that this Plan is a climate mitigation and greenhouse gas reduction plan, not a comprehensive plan to adapt and become resilient to the effects of climate change. That said, as we work toward our 2030 and 2050 goals, the State will support residents and communities in adapting to the climate impacts we are already facing, especially those in historically disadvantaged and underserved communities. Additionally, mitigation and adaptation are not mutually exclusive – their actions often overlap and benefit each other. Still, while there are climate adaptation considerations in this document, they do not constitute a holistic climate adaptation strategy for Michigan.

Concerted action by all Michiganders will be required to achieve the steep reductions in GHG emissions our state needs to achieve its goals. Fortunately, our communities, businesses, and institutions have already stepped up and created strong momentum for us to build upon. As described further below, the State of Michigan is also leading by example with Governor Whitmer directing state departments to use all the tools at their disposal to reduce GHG emissions in their operations and otherwise act on climate. (See Leading by Example in State Government)

While the objectives detailed in the rest of this Plan are ambitious—and in some cases daunting—it is important to recognize that our journey to carbon neutrality has already begun thanks to the leadership, creativity, and ingenuity of Michiganders across our state.



INTRODUCTION

GOVERNOR WHITMER'S COMMITMENTS

Recognizing the urgency of the crisis and the opportunities to build a better future for Michigan as we reduce our GHG emissions (see *Why Climate Action Matters for Michigan*), Governor Gretchen Whitmer has taken bold and sustained action on climate change since taking office.

In September 2020, she signed Executive Directive 2020-10, which committed Michigan to a goal of achieving economy-wide carbon neutrality no later than 2050 and maintaining net negative greenhouse gas emissions (GHG) thereafter. Carbon neutrality means that any carbon dioxide released into the atmosphere is balanced by an equivalent amount being removed. She also reaffirmed the goals in Executive Directive 2019-12, which committed Michigan to pursue at least a 26-28 percent reduction below 2005 levels in GHG emissions by 2025. In addition to the goals set by these directives, Michigan joined 24 other states and Puerto Rico – under the umbrella of the U.S. Climate Alliance – in committing to an interim goal of a 52 percent GHG reduction by 2030.

Executive Directive 2020-10 charged EGLE, through its Office of Climate and Energy (OCE), with developing the *MI Healthy Climate Plan* to serve as this state's action plan to reduce GHG emissions and transition toward economy-wide carbon neutrality with a focus on solutions that support communities disproportionately impacted by the changing climate.

Michigan's Commitment

In addition to leadership from state government, this progress has been driven – and will continue to be driven – by the actions and commitments of Michigan's communities, businesses, and institutions, including, but not limited to, the examples below.

Leading communities: At least 16 Michigan communities, ranging from the City of Ann Arbor to Shelby Township, have set goals to be carbon neutral or to reach 100 percent renewable energy by 2050.

Tribal leadership: The Sault Ste. Marie Tribe of Chippewa Indians has a net-zero energy goal and aims to reduce greenhouse gas emissions by four percent per year.

Our largest universities: The University of Michigan committed to eliminate both direct emissions and emissions from purchased energy between 2025 and 2040. Michigan State University committed to carbon neutrality by 2050 with interim reduction goals.

Homegrown businesses: Steelcase has achieved carbon neutrality and has set a target to become carbon negative by 2030. Whirlpool set a net-zero emissions target in its plants and operations by 2030. Dow set a target of being carbon neutral by 2050. General Motors (GM) set a goal of carbon neutrality in its global products and operations by 2040. Ford Motor Company set a goal of carbon neutrality by 2050 and committed to powering its manufacturing plants with 100 percent locally sourced renewable energy by 2035. And many more Michigan businesses – large and small – are stepping up.

Our largest utilities: Consumers Energy set a goal of net-zero carbon emissions by 2040. DTE Energy set a goal to achieve net-zero carbon emissions by 2050 with interim reductions targets.

A Climate Plan Shaped by Michigan Residents

The Plan was developed by EGLE with input from hundreds of Michigan residents. To serve as the primary venue for gathering and channeling that input, Governor Whitmer created the Council on Climate Solutions through Executive Order 2020-182.

The Council consists of 14 Michigan residents appointed by the governor to represent a range of sectors, experiences, and expertise relevant to climate issues. Additionally, the Council includes the directors (or their designees) of EGLE and the Michigan Departments of Agriculture and Rural Development (MDARD), Labor and Economic Opportunity (LEO), Michigan Economic Development Corporation (MEDC), Natural Resources (DNR), Transportation (MDOT), and Health and Human Services (DHHS), as well as the State Treasurer and the Chair of the Michigan Public Service Commission (MPSC).

The Council met 14 times in 2021 to develop a common knowledge base on the climate challenge and discuss the content and recommendations laid out in this Plan and its appendices. To dig deeper and tap broader expertise across Michigan in key areas, five topical workgroups were formed to support the Council:

- **Energy Production, Transmission, Distribution, and Storage**
- **Transportation and Mobility**
- **Buildings and Housing**
- **Natural and Working Lands and Forest Products**
- **Energy Intensive Industries**

In addition to the above workgroups, an internal group led by EGLE staff provided recommendations on decarbonization related to materials management.

Hundreds of Michiganders participated in these come-one-come-all workgroups, the membership of which was open to the public. Each was co-chaired by a State of Michigan official and a private-sector resident with subject-matter expertise in the relevant field. These workgroups met periodically through much of 2021 and presented their recommendations to the full Council in the closing months of the year. Listening sessions were then conducted to receive public input on those recommendations (a complete set of which is provided in the appendices).

In 2022, EGLE released a draft of this Plan for public feedback, welcoming written comments and creating forums for the public to engage and comment on the plan. After overwhelming interest, EGLE extended the timeline for input. In addition to public forums, EGLE facilitated consultation with tribal governments and hosted meetings with Council and workgroup members, key stakeholders, and the Michigan Advisory Council on Environmental Justice (MAC-EJ).

17
Council on Climate Solutions meetings held to date (open to public)

2
Consultations with Tribal government

10+
Presentations from experts at Council meetings

6 TOPICAL WORKGROUPS

- Energy production, Transmission, Distribution, and Storage
- Transportation and Mobility
- Energy Intensive Industries
- Buildings and Housing
- Natural and Working Lands and Forest Products
- Materials Decarbonization (ad hoc)

1929 PUBLIC COMMENTS RECEIVED ON DRAFT PLAN

243
Original emails

1,570
Form message emails

2
Regular mail

114
Via 3 listening sessions

7 LISTENING SESSIONS 2021-2022

April 22, 2021 • May 5, 2021 • December 1, 2021 • December 2, 2021
January 26, 2022 • February 8, 2022 • February 14, 2022

WHY CLIMATE ACTION MATTERS FOR MICHIGAN

MICHIGAN IS FEELING THE IMPACTS OF CLIMATE CHANGE

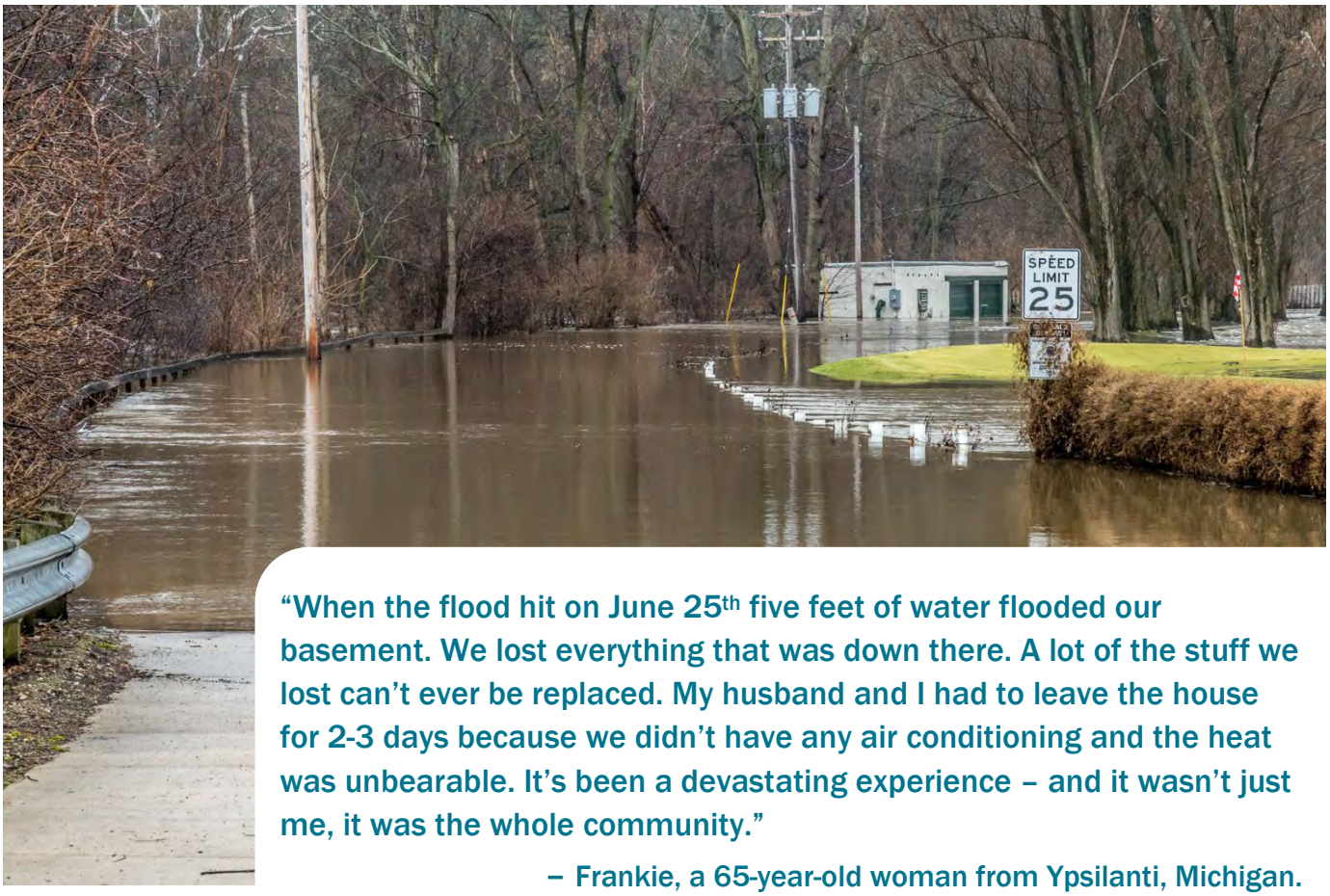
Immediate, aggressive action on climate change ensures that Michiganders – present and future – can thrive in Michigan.

In just the last three years, Michigan has felt the real impacts of climate change. The state has faced a polar vortex that forced residents to come together to keep the heat on, high lake levels that crumbled personal property and public infrastructure, record flooding that caused sewers to back up into homes, increased instances of disease-carrying insects, toxic algal blooms that put our waters in danger, the temporary closure of businesses that rely on seasonal consistency, the breaking of dams that led to the evacuation of a community, and week-long power outages.

Historically stable patterns are changing rapidly in unpredictable ways. Compared to 1900, Michigan is almost 3 degrees warmer and gets around five more inches of rain per year.

Frequent and intense storms

Michigan is experiencing historic levels of rain and intense storms. A continuation of extreme rain will lead to more property loss and infrastructure failures, an increase in the likelihood of contamination, bacteria, algal blooms in water supplies, and the risk of contracting waterborne diseases like Legionnaire's. The state has also seen extreme changes in Great Lakes water levels.



"When the flood hit on June 25th five feet of water flooded our basement. We lost everything that was down there. A lot of the stuff we lost can't ever be replaced. My husband and I had to leave the house for 2-3 days because we didn't have any air conditioning and the heat was unbearable. It's been a devastating experience – and it wasn't just me, it was the whole community."

– Frankie, a 65-year-old woman from Ypsilanti, Michigan.

Rapid temperature changes

Michigan summers are becoming hotter and drier. The latest science suggests that summers in Detroit in 2100 will feel like summers in Dallas do now. Extreme heat will lead to increased hospitalizations due to heat exhaustion and heatstroke, wildlife loss from habitat changes, and increased levels of mosquito and tick populations that carry diseases like West Nile Virus and Lyme Disease. As with intense rains, high heat can damage infrastructure and personal property. Michigan is already seeing roads and sidewalks buckle and break from rising temperatures. On the other side of the calendar, Michigan winters are becoming more unpredictable. In the last 10 years, the state has experienced three polar vortexes leading to irregular cold blasts.

Along with more severe extremes, uncertainty in temperatures has also presented newfound challenges, especially for seasonal activities and industries like farming, hiking, camping, boating, skiing, snowmobiling, and ice fishing. This uncertainty was especially prominent in March 2012 when the state experienced a record-breaking crop loss event when temperatures hit over 80 degrees causing Michigan cherry trees to bloom, only for the crop to be almost entirely lost when temperatures dipped back below freezing in April.

"In 2012, Michigan lost over 90% of its tart cherry crop because of erratically warm weather that fooled our cherry trees into blossoming while in frost season. Michigan's agriculture relies on relatively predictable, stable weather conditions. As the climate changes, we have to operate with increasing uncertainty. Some farmers have been forced to import cherries to make up for the losses, make expensive updates, or just leave the industry. Our industry has a rich, proud history in Michigan rooted in its soil, built by its waters, but now those same natural forces are having devastating impacts on our bottom line."

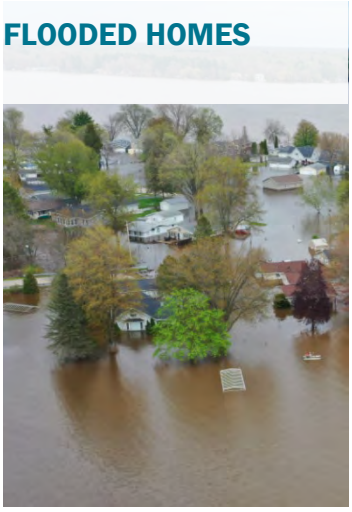
– Bob Sutherland, President of Cherry Republic

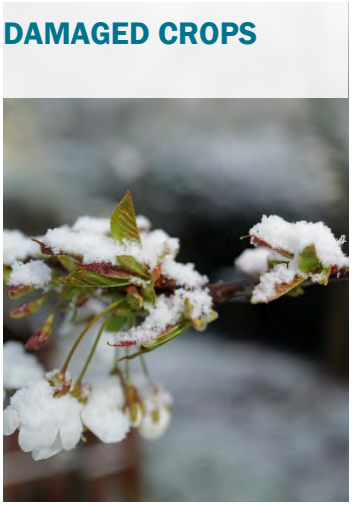
If we don't act aggressively to reduce GHGs, these impacts will only intensify and become more challenging and expensive for Michigan residents. It is imperative that we reduce emissions as quickly as possible and simultaneously prepare for the changes we cannot prevent.

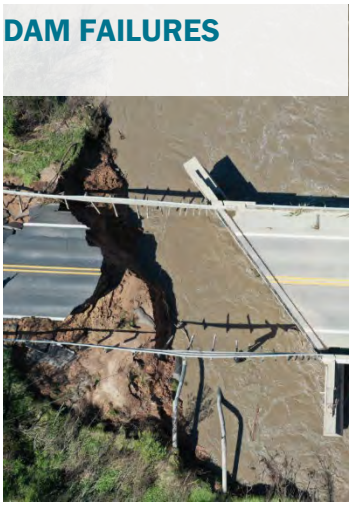
Importance of adaptation

The MI Healthy Climate Plan is a climate mitigation and greenhouse gas reduction plan, not a comprehensive plan to adapt and become resilient to the effects of climate change. That being said, Michigan families are already feeling the impacts of climate change – with the most vulnerable being hit hardest. Governor Whitmer and the State of Michigan are committed to continuing to support communities as they prepare for and adapt to climate change. This will be done through regular engagement and communication, the sharing of tools and best practices, and a commitment to robust emergency response protocols in the event of a disaster.

The State is also working to make state-owned infrastructure more resilient and is providing funding and guidance to communities to help them do the same. Mitigation and adaptation are not mutually exclusive. In fact, combining the two is essential. According to the IPCC's most recent report on impacts, adaptation, and vulnerability, adaptation measures become less effective the more the planet warms, and mitigation efforts that do not anticipate future conditions are less effective. We must adapt to the existing impacts of climate change as we work to decarbonize our economy.







Action is an Opportunity to Improve Health Outcomes

Protecting our public health, air, and water by reducing our reliance on fossil fuel technologies like coal-fired power plants.

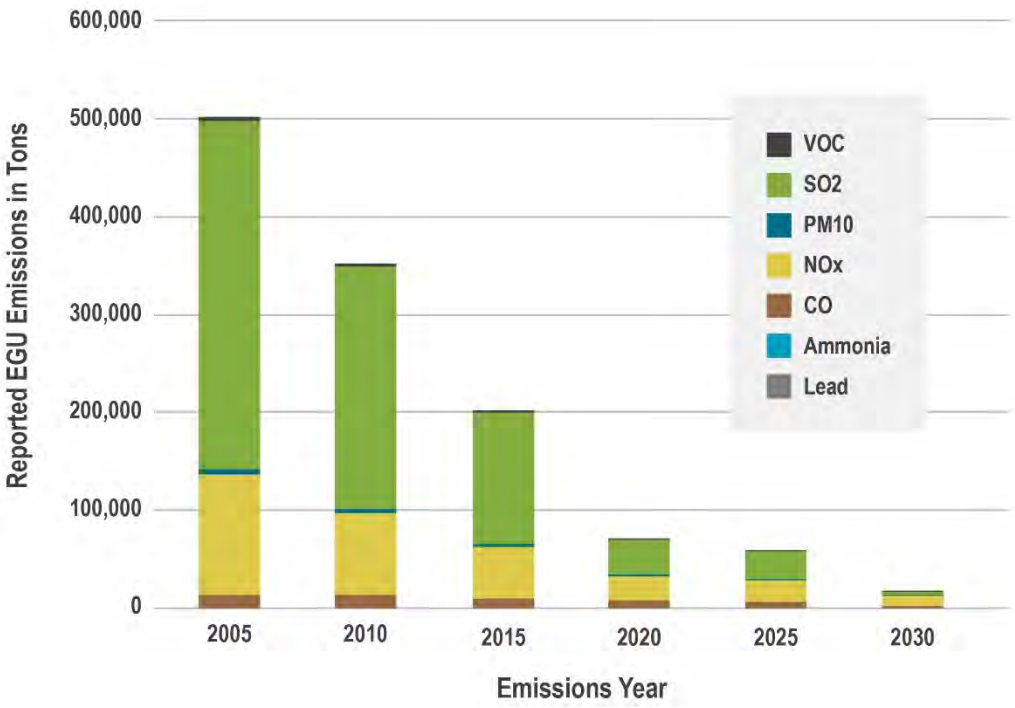
As Michigan implements the strategies in the Plan to reduce GHG emissions, levels of other harmful pollutants in our environment will continue to drop in tandem. That's why determined action to achieve carbon neutrality is an opportunity to dramatically improve public health outcomes, reduce health costs, and avoid lost wages from trips to the doctor, emergency room, or worse. This is especially true for families and communities historically impacted by pollution.

Easier to breathe

To take the example of one air pollutant, studies have found that breathing in particle pollution—of which coal-fired power plants are a major source – leads to decreased lung function, increased levels of asthma, exacerbated respiratory symptoms such as coughing or difficulty breathing, and even premature death in people with heart or lung disease. According to state and national data, Michigan's particulate matter pollution from power plants has dropped 73 percent since 2005 as the state has transitioned away from coal-fired power to cleaner energy sources.

As Graph A shows, closing coal-fired power plants and transitioning to cleaner energy sources has spurred similar emissions reductions in Michigan across the five common air pollutants for which the U.S. Environmental Protection Agency sets National Ambient Air Quality Standards (because of their respiratory, cardiovascular, and other harms). Emissions of those pollutants from energy generation in Michigan has dropped 85 percent since 2005. With the closure of our state's remaining coal-fired power plants by 2030, that figure is expected to rise to 96.4 percent. In addition, estimated PM2.5 emissions from electric generating utilities declined from 2,302 tons in 2005 to 1,349 tons in 2020.

Criteria Pollutants from EGUs



All data is in estimated tons of emission in 2017

Sources: Michigan Air Emissions Reporting System (MAERS) and the EPA's triennial National Emissions Inventory (NEI)

Demonstrating how this Plan's primary focus on decarbonizing Michigan's energy production, transportation, and buildings will drive public health benefits, Table A shows the extent to which each of those sectors contribute to emissions of those five common air pollutants.

The transportation sector is currently the largest source of those pollutants in Michigan (Table A). Federal auto emission standards have and will continue to reduce pollution from internal combustion engines. In fact, total emissions dropped around 20 percent between 2014 and 2017. However, we can accelerate those reductions by electrifying our transportation sector. As Michigan residents transition to electric vehicles, we can expect greater improvements in air quality and a decline in related health problems. Better public transit and an increased availability of walking and biking opportunities will also reduce harmful emissions and give residents better opportunities for exercise and enjoyment of Michigan's recreational amenities.

This is particularly important in areas disproportionately impacted by pollution from the concentration of major transportation corridors there. As Michigan works to decarbonize our transportation sector according to this Plan, state and local transportation planning processes should more fully account for health impacts and emphasize solutions that will accelerate the reduction in transportation-related air pollution.

Emissions by Pollutant

Pollutant	Electricity Generating Units	Residential Heating	Transportation		
			Heavy Duty	Light Duty	Refueling
Ammonia	98	3,592	220	2,830	
Carbon Monoxide	10,287	82,401	38,133	641,545	
Nitrogen Oxides	38,704	18,053	39,332	66,297	
PM10 Primary	1,134	10,560	4,095	4,919	
Sulfur Dioxide	66,296	485	106	533	
Volatile Organic Compounds	971	11,310	4,342	52,992	4,456

All data is in estimated tons of emission in 2017.

Sources: Michigan Air Emissions Reporting System (MAERS) and the EPA's triennial National Emissions Inventory (NEI)

While improved air quality is the most direct and widely recognized link between reduced GHG emissions and improved public health, Michigan's pursuit of carbon neutrality can also benefit our land and water. To take one example, Michigan's more than two dozen coal ash landfills are another legacy of our state's historic coal-fired power production. Located close to current and former plants—and in some cases residential areas—these landfills have a history of leaking into underlying aquifers that residents rely on for drinking water. Our transition away from reliance on coal-fired power production will help avoid this contamination in the future.

Finally, we must recognize that climate change is already—and will continue to—have significant public health consequences. Power outages, extreme heat events, exposure to bacteria during sewer backups, and other such climate-related impacts harm Michigan families. Avoiding the most severe such consequences by reducing our GHG emissions as rapidly as possible will help Michigan avoid costly and devastating health outcomes to the greatest extent possible.

In short, decarbonizing Michigan's economy is a powerful strategy for improving the health and well-being of our 10 million current residents and the generations to come.

"The [Midland] flood in 2020 had great impact on those with diabetes in this area. We had patients that lost homes or were living outside of their home for a long time after the flood. This led to issues with refrigeration for their insulin and obtaining supplies for their insulin pump because they had no address for their durable medical equipment company to ship their diabetes supplies to."

– Erin, RN, CDCES, Diabetes Center Manager, MyMichigan Medical Center, Midland

Action is an Opportunity to Right Environmental Injustices

Addressing historical harms, prioritizing environmental justice, and creating equitable opportunities for all Michigan residents.

The State of Michigan should be a place where everyone, no matter their zip code or what is in their wallet, should have the opportunity to thrive – to meet their basic needs, enjoy the dignity of good work, and live in a healthy community with access to affordable housing, water, heat, power, and transportation. Unfortunately, this has not always been the case, particularly for Black, brown, indigenous, rural, and low-income people.

Environmental justice communities are most often communities of color and/or low-income

> *The State of Michigan defines environmental justice as the equitable treatment and meaningful involvement of all people, regardless of race, color, national origin, ability, or income in the development and application of laws, regulations, and policies that affect the environment, as well as the places people live, work, play, worship, and learn.*

communities. In addition to facing disproportionate impacts from environmental harms, they generally have been excluded from the opportunities enjoyed by most of society and left behind during major historic economic shifts like our current transition to carbon neutrality.

Environmental injustices are part of a long history of race-based discrimination rooted in the sustained actions, behaviors, and attitudes of institutions and individuals and encoded in our laws at every level. As a result of this structural racial discrimination, environmental justice communities disproportionately neighbor highways, power plants, factories, and other facilities that release pollution into the air and water. Exposure to this pollution over time leads to health issues and lower quality of life. These communities also tend to enjoy fewer trees and lack access to green spaces and other quality outdoor recreation amenities.

Environmental justice considerations are a key component of equitable climate action and will continue to be a priority for the state as it works to eliminate racial disparities impacting the health and well-being of Michiganders. Recognizing that bringing communities of color off the frontlines of the climate crisis and ensuring that they will be full beneficiaries of a carbon neutral economy, Governor Whitmer called on those developing the MI Healthy Climate Plan to design and recommend decarbonization strategies that will prioritize and advance equity and environmental justice. The transition to a carbon neutral economy has the potential to help alleviate existing environmental injustices, address historical harms, and create new opportunities for Michiganders.

Disproportionate impacts

While Michiganders have relied for generations on the burning of fossil fuels for everything from driving to work to cooking dinner and turning on the lights, many of Michigan's most disadvantaged communities and communities of color have faced the brunt of the environmental and other impacts of an economy based on fossil fuels.

In the electricity sector, high-emitting power generation facilities and related fossil-fuel infrastructure are often located in low-income communities and communities of color. Meanwhile, in Michigan, households with an income below the Federal Poverty Line spend 18 percent of their income on energy, compared to an average of 3 percent for the overall population.

In the transportation sector, high-emitting transportation corridors often run right through low-income communities and communities of color, splitting historic neighborhoods in two, burdening them with higher pollution, and otherwise undermining their quality of life.

In homes and businesses, many disadvantaged communities live and work in subpar buildings, face higher energy burden, and are subject to health-related impacts from natural gas appliances, all while lacking access to the investments in energy efficiency and onsite renewable energy seen in other communities.

In the industrial sector, low-income communities and communities of color often endure the environmental and other harms of life on the fence lines of heavy industrial facilities.

Michigan recognizes that tribal nations have also faced disproportionate burdens in our fossil fuel economy and are especially vulnerable to the impacts of climate change because of their deep ties to the land and reliance on hunting, fishing, and gathering. Oil spills and other such contamination have impacted resources like wild rice. The changing climate threatens the sustainability of the Great Lakes fishery which tribal fishers rely upon to earn a living and feed their families. Many cultural practices and traditions require access to species, like the maple tree, that are put at risk by climate change. Michigan's climate strategies and actions must honor, embrace, benefit, and not interfere with the cultural heritage and treaty rights of federally recognized tribal nations in Michigan and preserve the fragile balance of the Great Lakes ecosystem at the heart of that heritage and those rights.

Just transition

As Michigan transitions away from fossil fuels and traditional carbon heavy industries, it is critical to prepare our workforce for the new opportunities of a carbon neutral economy and ensure all Michigan families have access to those opportunities, particularly those who have not enjoyed equitable access in the past. To ensure our transition to carbon neutrality is just—and avoid responding to climate change in a way that reinforces challenges that historically disadvantaged communities have faced—we need to proactively and intentionally plan for equity and environmental justice. During the transition to a carbon neutral economy, Michigan's most vulnerable communities must be prioritized. The transition to a carbon neutral Michigan needs to happen as fast as possible without leaving anyone behind.

In response to a 100-year rain event, the Macomb County Health Department surveyed homes.

"The responses to our post-flood survey allowed us to see the impact socioeconomic factors have on our population's health. We found it concerning that low-income households (37%) were more than twice as likely to report a decline in their health status than high income households (16%). This has provided an opportunity to focus our messaging and community engagement activities going forward to help us better prepare for future emergencies."

Tom, Environmental Health Services Division Director, Macomb County Health Department

Action is an Economic Opportunity for Michigan

Creating good paying jobs for Michigan families, increasing our state's economic competitiveness, and lowering costs as we pursue carbon neutrality.

Climate change is already resulting in economic costs to families and businesses across the state, but strategic and aggressive climate action also presents immediate and long-term opportunities to create economic growth, support good-paying union jobs, and lower costs for working families. Immediate and sustained action on climate is also necessary for Michigan to remain globally competitive in the decades ahead. The transition to a carbon neutral Michigan needs to happen as fast as possible without leaving anyone behind.

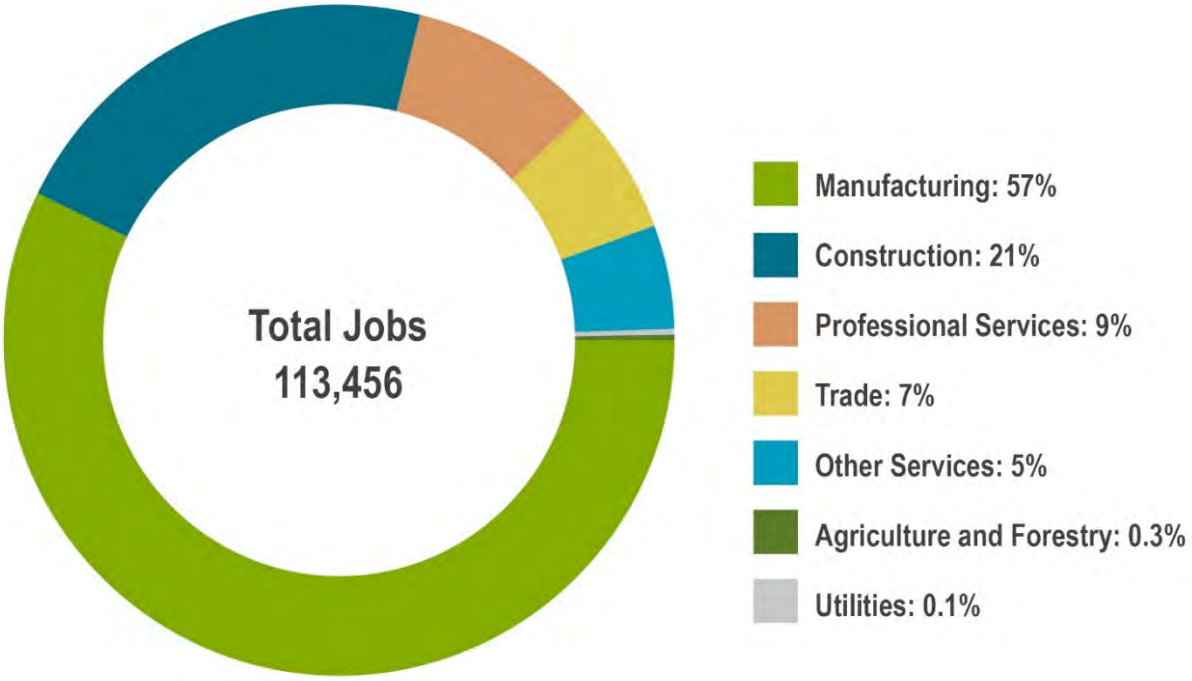
Economic opportunities

Businesses are increasingly focused on climate and are looking to invest and locate in states that embrace clean energy, advanced manufacturing, and the next generation of transportation. If the State acts aggressively on climate and builds on Michigan's strengths in manufacturing and the automotive sector, we can ensure that homegrown companies stay in Michigan and that the state is more attractive to new economic development opportunities.

In 2021, Michigan was ranked as a top 3 state for sustainable development. Over the past three years, according to the Michigan Economic Development Corporation, Michigan has received more than $16 billion in private investment from mobility and automotive companies. In early 2022, GM announced the company's largest ever investment—a total of $7 billion to develop a new battery factory in the Lansing area and convert an existing factory in Orion Township to electric pickups. This major stake in making Michigan an electrified transportation leader will create 4,000 new jobs and retain another 1,000 existing ones in our state. Michigan has also seen significant investments in clean energy projects with more than $5 billion worth of renewable energy projects coming online since the passage of the state's clean energy law in 2008.

Good-paying jobs

Michigan is home to over 113,000 clean energy jobs in every region of Michigan with the majority in manufacturing (57 percent) and construction (21.7 percent). Showing its resilience and staying power, Michigan's clean energy industry rebounded faster than the state's overall economy following the initial onset of the COVID-19 pandemic.



The largest number of clean energy jobs in Michigan are in energy efficiency, ranging from HVAC installation to advanced materials manufacturing. The fastest-growing industry is advanced transportation, which employs more than 24,000 Michiganders. Over two-thirds of Michigan's clean energy jobs are with small businesses employing less than 20 workers. Clean energy jobs pay up to 25 percent more than the national median wage and are more likely to be unionized and come with health care and retirement benefits than the rest of the private sector. Many of these jobs do not require college degrees. Growing our clean energy workforce, connecting opportunities to the Michiganders who need them most, and providing workers the training and skills that they need to succeed will take sustained, deliberate action from the State and the business community.

"The transition to electric vehicles is a big deal for union workers, union electrical contractors, businesses, and working families. As a union journeyman, I've worked to provide safe, reliable electrical systems for communities and homeowners, but I am so excited about the new opportunity to install and provide service for electric vehicle charging stations and be a part of this transition. This transition is critical to secure Michigan's spot as the home to the future of electric vehicles."

- Karen from Detroit

Reduced costs for working families

Climate action will also lower costs for working families and small businesses. To achieve our GHG reduction goals, Michigan must make transformative investments in weatherizing and reducing energy waste in our homes and places of business. Combined with the increased use of renewable energy, this will lower the monthly utility bills for Michigan families and businesses. At the same time, the transition to electric vehicles will reduce costs related to fueling and maintaining our cars, while improved public transit will help Michiganders cut the share of our incomes spent on transportation and provide the 8% of Michigan households without personal vehicles greater access to jobs and other opportunities.

Examples of the powerful math behind these benefits include the following:

- For every $1 invested in reducing energy waste in our homes – through more efficient windows, lighting, and other energy-saving technologies – homeowners save more than $3.20 in reduced future energy bills. Energy efficiency also reduces energy burden by as much as 25 percent, translating into more than $400 in annual savings for households.
- The levelized cost of electricity for new onshore wind and solar resources that are coming online in 2023 was $25.55/MWh and $25.89/MWh respectively, compared with $34.78/MWh for new combined-cycle natural gas units. Adding new wind and solar resources is comparable – and in many cases cheaper – to the cost of running existing power plants.
- Michigan sends billions of dollars out-of-state annually to purchase fossil fuels. If we produce more of our energy right here in Michigan from clean, renewable resources, we will be more energy independent and lower costs for working families.
- Owners of electric vehicles are expected to save between $6,000 to $10,000 over the life of the vehicle, compared to a gas-powered vehicle, because charging is half as expensive as the equivalent amount of gas and electric vehicles require half as many repairs and cost half as much to maintain.

"We recently bought an electric vehicle, installed solar panels on our roof, and switched to a geothermal HVAC. We're saving money on utility bills and gasoline without compromising any of our needs. When I tell people about this, they wonder how I could afford it. There are a lot of generous financing options and federal tax credits for these investments. Depending on the project, the payments might be around the same as the energy savings and the project will pay for itself right away! You can make modest investments, lower your bills, and be a part of the climate solution right now."

– John, Farmington Hills resident

High cost of inaction

While the opportunities to create good jobs, cut costs, and grow our economy should be more than enough to inspire ambitious action to decarbonize our economy, it is also important to remember that climate *inaction* will come at a high price for Michiganders. Climate change increases the likelihood of natural disasters, damaging infrastructure that is costly to repair and disrupts business. More erratic and unpredictable temperatures lead to uncertainty and losses for our farmers and other sectors that rely on seasonal consistency. And extreme weather worsens health outcomes leading to lost productivity and wages.

Michigan currently spends millions of dollars annually responding to climate-related emergencies and other impacts. Early intervention is a much sounder strategy with a much better return on investment. According to a recent study, the state will avoid **$4 to $11 worth of future damages** **for every $1 it commits to climate adaptation**.

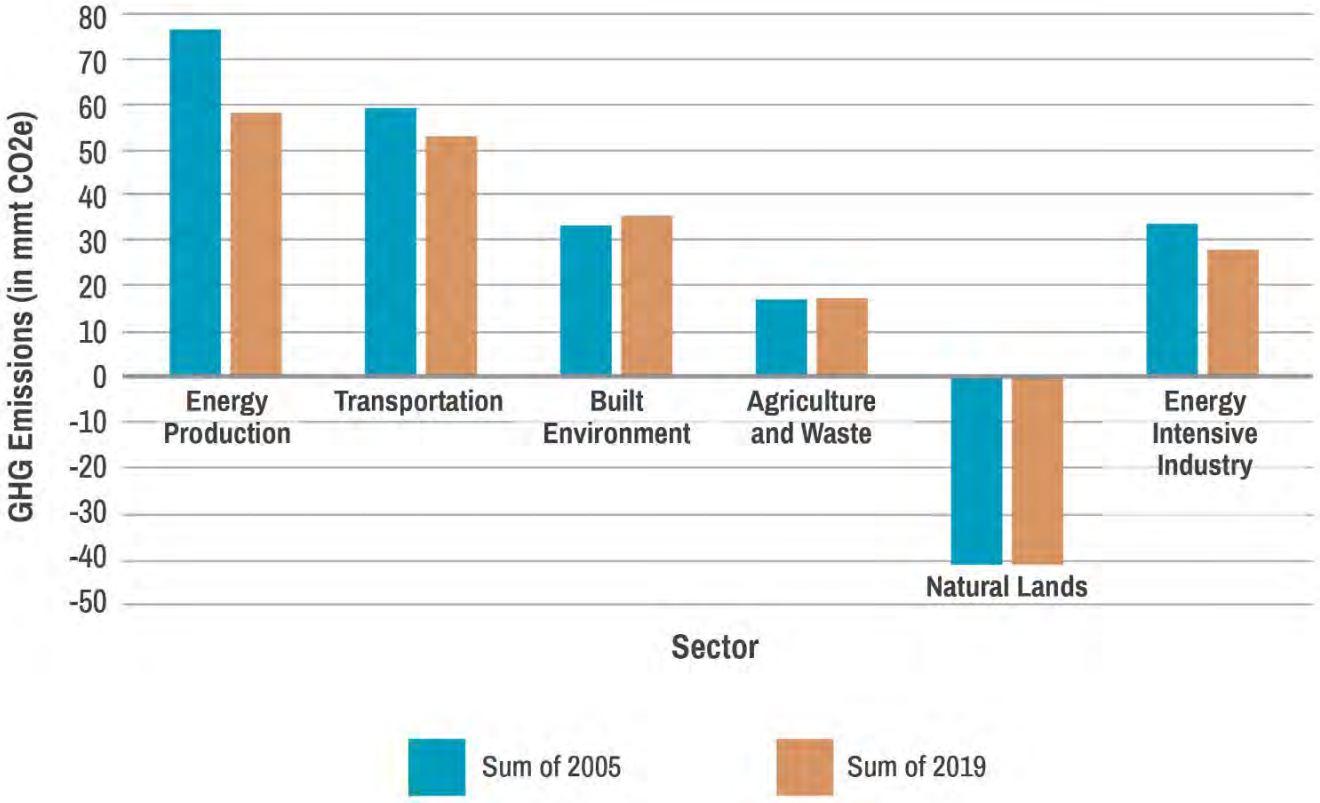
Climate action will spur innovation, increase the state's economic competitiveness, create good-paying jobs for Michigan workers, and cut costs for working families. This Plan sets the state on track to a more prosperous and sustainable Michigan.

MICHIGAN'S GREENHOUSE GAS EMISSIONS

Governor Whitmer's emissions reduction goals use a 2005 baseline for Michigan's GHG emissions, which can be categorized into five key sectors: energy production, transportation, the built environment, natural and working lands, and energy-intensive industries. The following uses Rhodium Group's 2021 emissions outlook data to summarize the share of Michigan's GHG emissions that come from each sector and provide a basic sense of the task ahead and the areas of our economy with the furthest to go in our quest for carbon neutrality.

The electric power sector and the transportation sector are the state's two leading sources of GHG emissions with the transportation sector set to eclipse the electric power sector imminently. Emissions from heating Michigan's buildings and running fossil-fuel-burning appliances account for the third largest contribution. Energy-intensive industries contribute a similar level of emissions to buildings—from onsite fuel usage and emissions inherent in certain industrial processes like cement manufacturing. Natural and working lands – which include emissions from agriculture and land-use changes (i.e., developing green spaces or impacting wetlands) – contribute the smallest percentage of overall emissions. However, because natural and working lands also present an opportunity to capture GHG emissions—an important piece of the carbon neutrality puzzle—they should not be undervalued or overlooked.

Greenhouse Gas Emissions by Source



Energy production

In 2005, the power sector in Michigan emitted 76.55 million metric tons (mmt) of carbon dioxide equivalent emissions (CO2e). Those emissions came primarily from coal-fired power plants, followed by natural gas power plants. Michigan also benefits from a diverse power sector that includes nuclear power plants and the pumped hydro facility at Ludington. Through the closure of coal plants and the expansion of renewable energy resources, power sector emissions in Michigan fell to 58.2 mmt CO2e in 2019 – a 24 percent decrease over that decade and a half period.

Transportation

In 2005, the transportation sector in Michigan emitted 59.26 mmt CO2e. Most of those emissions came from light-duty passenger vehicles and heavy-duty freight trucks (our state of 10 million people has nearly 7 million vehicles!). As electric vehicles became more available and modern internal combustion engine (ICE) vehicles became more fuel efficient, transportation emissions dropped slightly to 53.04 mmt CO2e in 2019 – a 10 percent reduction since 2005.

Built environment

In 2005, homes and businesses emitted 33.39 mmt CO2e, mostly from the use of sources like natural gas, fuel oil, or propane for heating and appliances. Driven by increased emissions from commercial buildings, this sector saw a slight uptick to sector-wide emissions of 35.61 mmt CO2e in 2019.

Energy-intensive industry

In 2005, Michigan's oil, gas, and industrial sectors emitted 33.78 mmt CO2e. Michigan has a rich history of manufacturing, and most of these emissions came from the process of producing new goods, like iron, steel, cement, and chemicals. Industry is always innovating and improving efficiency, leading to reduced emissions of 28.05 mmt CO2e in 2019 – a 17 percent change in the right direction.

Natural and working lands

Michigan has a unique diversity of land uses and ecosystems. Agricultural soil management is a major source of emissions from this sector, primarily from the large-scale farm operations in the southern portion of the state, while the forests in the north are the state's major carbon sink. This sector's net GHG emissions have remained almost unchanged over the past decade and a half. Agriculture and waste sources emitted 17.12 mmt CO2e in 2005 and 17.37 mmt CO2e in 2019. Natural lands sequestered 41.35 mmt CO2e in 2005 and 41.41 mmt CO2e in 2019.

While our emissions are projected to stay on a downward trend, we need to accelerate reductions across all sectors to meet our decarbonization goals on our established timelines. Reducing our emissions at the scale necessary will take concerted action at the international, federal, state, local, and individual levels. To track progress of the MI Healthy Climate Plan and help identify the areas for greatest GHG reduction potential, Michigan will develop a GHG inventory working with public and private partners and stakeholders.

A CARBON NEUTRAL MICHIGAN

While we are immediately focused on the short-term—and the objectives in the *Roadmap to 2030* section below—our long-term goal to achieve economy-wide carbon neutrality by 2050 is no less urgent. Economy-wide carbon neutrality means that every sector of Michigan's economy – energy production, transportation, built environment, natural and workings lands, and energy-intensive industry – will work together to meet our decarbonization goals. Reaching our mid-century milestone will require particularly substantial effort and innovation in the sectors of our economy that are hardest to decarbonize, including industry, buildings and housing, and agriculture. Since these sectors will take strategies and approaches that are not yet fully developed, we must start now. Also, we cannot take steps between now and 2030 that will jeopardize our ability to meet our 2050 goal.

But what does a carbon neutral Michigan look like? If we take a creative, strategic, and aggressive approach to reducing our GHG emissions, Michigan will be a state where residents enjoy better health outcomes and an improved quality of life; working families have more opportunities, high-paying jobs, and a lower cost of living; equity is centered in every decision; our global leadership in clean innovation and related economic development drives sustained prosperity; and everyone has greater access and a deeper connection to our state's natural beauty.

In Michigan in 2050…

As we implement the strategies in this Plan and transition Michigan to a thriving carbon neutral economy—while mitigating and adapting to the negative impacts of climate change—Michigan can take transformative steps toward a future in which:

Every individual has clean air to breath and clean water to drink.

Every business and household has access to affordable energy sourced from reliable, clean energy.

Every worker has a good-paying, sustainable job to support their family.

Every resident has access to clean, affordable transportation.

Every family lives in a healthy, sustainable, efficient home.

Every individual has easy access to healthy, affordable, local food.

Every resident has safe, natural spaces to enjoy.

Every community has the resources to be resilient to the impacts of climate change.

Michigan has addressed racial disparities in health outcomes.

Michigan is globally known for its leadership in clean innovation and industry.

Michigan's land and resources are abundant and healthy.

Michigan has mitigated the worst impacts of climate change and worked to adapt and become resilient to existing impacts of climate change.

As we look to this bright future, we know the best solutions to achieve these goals will emerge and evolve through innovations in technology, strategy, and policy, as well as individual and community level problem-solving. This work must start now and continue through 2050 and beyond.

A ROADMAP TO 2030

The State of Michigan has committed to carbon neutrality by 2050 with 52 percent GHG emissions reductions by 2030 as an interim target. Achieving our 2030 goal will require Michigan to reduce annual GHG emissions by approximately 92.95 million metric tons of CO2 equivalent based on today's emissions levels.

Sustained, aggressive action across Michigan's economy is necessary to reach these targets. A variety of factors will determine the extent to which various sectors and subsectors reduce emissions during this time, including technological breakthroughs and constraints, economic opportunities and costs, and public support/consumer demand for change.

The MI Healthy Climate Plan intends to spur the changes that are imperative—that must happen, and happen now, to meet our goals. It also seeks to shape *how* Michigan achieves carbon neutrality by recommending strategies that will maximize the benefits for Michigan families from decarbonization. To that end, the Plan focuses most heavily on the three sectors with the greatest opportunity for rapid and substantial gains in GHG reductions—energy production, transportation, and the built environment. It also prioritizes environmental justice across all actions and spotlights pathways to carbon neutrality that will lead Michigan to better health outcomes, good jobs, and economic prosperity for all Michiganders.

This 'Roadmap' provides recommendations but should not limit additional actions. State government, local governments, tribal governments, and private institutions should strive to move beyond these recommendations and seek innovation and new approaches to reduce GHG emissions. Across all sectors, Michigan should use every tool and chase every dollar available, including Infrastructure Investment and Jobs Act funds, to help meet our climate goals.

NOTE: This section borrows liberally from the concepts and language that the five topical workgroups submitted to the Council on Climate Solutions along with their recommendations. The workgroups included: Energy Production, Transmission, Distribution, and Storage; Transportation and Mobility; Buildings and Housing; Energy Intensive Industries; and Natural and Working Lands and Forest Products. In addition to the above-listed workgroups, an internal group led by EGLE staff provided recommendations on decarbonization related to materials management. This section intentionally includes environmental justice recommendations in every sector, not just the environmental justice section.

Key Recommendations

In the pages that follow, this Roadmap offers several recommendations in each of the areas below with a brief background discussion of each. A brief summary of key recommendations is provided here.

Commit to Environmental Justice and Pursue a Just Transition: Ensure that at least 40 percent of state funding for climate-related and water infrastructure initiatives benefit Michigan's disadvantaged communities (in line with the federal government's Justice40 guidelines for federal funding); that Justice40 is developed in partnership with leaders in disadvantaged communities; and that Michigan emphasizes a just transition for all workers through proactive engagement, job training, and workforce development.

Clean the Electric Grid: Generate 60 percent of the state's electricity from renewable resources and phase out remaining coal-fired power plants by 2030. Limit energy burden from powering and heating homes to not more than 6 percent of annual income for low-income households.

Electrify Vehicles and Increase Public Transit: Build the infrastructure necessary to support 2 million electric vehicles on Michigan roads by 2030. Increase access to clean transportation options – including public transit – by 15 percent each year.

Repair and Decarbonize Homes and Businesses: Reduce emissions related to heating Michigan homes and businesses by 17 percent by 2030. Increase investments in repairing and improving buildings to reduce costs for working families and small businesses.

Drive Clean Innovation in Industry: Encourage clean innovation hubs where private enterprises strategically co-locate and collaborate to develop and deploy new, cleaner manufacturing technologies and conduct research and development to reduce emissions from hard to decarbonize industries. Triple Michigan's recycling rate to 45 percent and cut food waste in half by 2030.

Protect Michigan's Land and Water: Protect 30 percent of Michigan's land and water by 2030 to naturally capture GHG emissions, maintain and improve access to recreational opportunities for all Michiganders, and protect biodiversity. Leverage innovative strategies to support climate-smart agriculture.

Commit to Environmental Justice and Pursue a Just Transition

We are committed to addressing past, present, and future environmental injustices and providing equitable access to the jobs and other benefits of Michigan's carbon neutral future. This section of the Plan focuses on policies and programs that will ensure the equitable treatment and meaningful participation of all Michiganders in that future.

Key Strategies

- **Justice40** – Ensure that at least 40 percent of state funding for climate-related and water infrastructure initiatives benefit Michigan's disadvantaged communities, in line with the federal government's Justice40 guidelines for federal funding. Develop Justice40 in close partnership with leaders in disadvantaged communities.
- **Environmental justice analysis** – Engage all state agencies in determining how environmental justice screening tools can assist them in designing better information gathering, outreach, engagement, and decision-making processes to reduce existing and future impacts to residents (this includes permitting decisions). Expand on the efforts of the Michigan Public Service Commission to conduct an environmental justice and health impact analysis as part of Integrated Resource Planning (IRP) so the potential community impacts of utility investment decisions are more fully considered.
- **Workforce development and job training** – Strengthen and create workforce development, job training, pre-apprenticeship/apprenticeship, joint labor management training, and other such programs for in-demand clean energy jobs – from pre-weatherization services to grid maintenance, electric vehicles, and renewables. Ensure these programs are federally certified by the Department of Labor where applicable. Incentivize workforce development and training for workers experiencing energy-related employment transitions and those in underrepresented or disproportionately impacted communities.
- **Just transition** – Expand transparency around the Energy Transition Impact Project's work and provide financial support and best practices to communities addressing economic transitions from closures of fossil fuel facilities and other large industrial operations. Work with employers and other partners to develop sector-specific retraining solutions.
- **Development, retention, and attraction of clean energy businesses** – Expand efforts to support business development, retention, and attraction around clean energy businesses. Conduct trainings to support minority-owned, veteran-owned, women-owned, tribal-owned clean energy businesses and help them compete in utility and state procurement programs. Identify tools and best practices to expand opportunities for these firms in Michigan.

Beyond committing to the actions above, this Roadmap includes recommendations infused with environmental justice considerations in each of the major GHG-emitting sectors. For example, this Plan also includes commitments to reduce energy burden for disadvantaged communities, strengthen ratepayer input at the Michigan Public Service Commission (MPSC), and spur more equitable investments in energy saving home repairs, public transportation, and clean energy solutions for schools.

Background

The State of Michigan should be a place where everyone has the opportunity to thrive, no matter their zip code or the contents of their wallet. This includes the opportunity to enjoy the dignity of good work and live in a healthy community with access to affordable housing, water, and utilities. Unfortunately, this has not always been the case, particularly for Black, brown, indigenous, and low-income people.

The United for ALICE project documents the struggle experienced by the Asset Limited, Income Constrained, Employed segment of our population. It shows that even with unemployment at record low levels, much of our population struggles to make ends meet. In Michigan as a whole, 38 percent of the population falls into this category with 13 percent below the poverty line and 25 percent above it but still not making ends meet. More than half of Michiganders across much of the Upper Peninsula and the central portion of the Northern Lower Peninsula fall into this category. In Detroit, the figure is approximately 70 percent.

These Michigan families face daily "choices" between paying rent, staying current on utility bills, and buying food for their children. With limited resources, they are also particularly vulnerable to the extreme weather, economic transitions, and other impacts of climate change. If Michigan does not proactively intervene, climate change will only deepen these existing harms and inequities. We must seize our transition to carbon neutrality as an opportunity to chart a new path.

Guarding against future challenges

Many of the strategies laid out in this plan will help right environmental justice wrongs from the past. Renewable energy and electric vehicles will help clean the air, and green infrastructure will help keep our cities cooler and utility bills lower.

However, if we are not deliberate in moving toward an environmentally just future, we run the risk of creating new inequities as we transform the way we create and consume energy. For example, electric vehicles are not yet affordable or accessible for all Michiganders, so the Plan includes a broad transportation decarbonization strategy to make walking, biking, and public transit more accessible to Michigan families and electric vehicles cheaper and easier to charge.

In the electric sector, there is no automatic guarantee that retiring coal facilities and increasing use of other electric generation assets – current or future – will benefit Michigan communities. That is why the Plan calls for holistic energy planning and increased consideration of environmental justice in decision making. Additionally, while more renewable energy will help all Michiganders, access to the benefits of renewable energy may not be equitable. Thus, the Plan calls for funding programs focused on Michigan's disadvantaged communities. Finally, we must take particular care to ensure that the energy transition does not result in a disproportionate energy burden for Michigan's disadvantaged communities. In other words, we must do everything we can to avoid a future in which utility bills cost families in those communities an even greater share of their disposable income.

Our frontline communities will also be hit first and hardest by the impacts of climate change. An environmentally just future includes making sure that no one experiences disproportionate harm from the extreme heat and precipitation that Michigan will experience over the next century no matter how quickly we decarbonize. This Plan does not contain a holistic adaptation and resilience strategy, though resilience will be core to our Plan implementation work.

Justice in funding decisions

In January 2021, the White House created the Justice40 Initiative by executive order. It aims to deliver to disadvantaged communities 40 percent of the overall benefits of relevant federal investments. As a part of this Plan, Michigan has committed to aligning our relevant federal and state investments with this initiative.

The State is currently waiting for guidance from the federal government on how to effectively implement Justice40. The State will also actively seek input from environmental justice communities, tribal governments, and other stakeholders as we define the scope, benefits, and community qualifications for this initiative and determine how to best implement Justice40 and track progress.

Inclusive and transparent engagement and decision-making

In addition to funding decisions, we must ensure all state agencies are considering environmental justice across their operations and decision making.

As mentioned above, the Plan calls for all state agencies to evaluate current information gathering, outreach and engagement, and decision-making processes and determine how environmental justice screening tools can assist them in avoiding and correcting disproportionate impacts on disadvantaged communities.

It also calls for the expansion and improvement of efforts initiated by EGLE and the MPSC to conduct an environmental justice and health impact analysis as part of utility Integrated Resource Planning, so that the potential community impacts of utility investment decisions are more fully and faithfully considered. The Plan also includes multiple opportunities to support meaningful engagement of Michigan's environmental justice communities, including calling for additional funding for the Utility Consumer Representation Fund, which is managed by the Utility Consumer Participation Board, to support ratepayer advocates in their interventions at the MPSC.

As the Plan is implemented, the OCE will establish consistent and transparent practices for engaging

EXPANDING ON THE WORK OF THE ENVIRONMENTAL JUSTICE PUBLIC ADVOCATE

In 2019, through Executive Order 2019-06, Governor Whitmer created the Office of the Environmental Justice Public Advocate (OEJPA).

To gather input from impacted communities, the OEJPA has hosted 8 regional roundtables across the state to discuss environmental justice challenges and identify opportunities to pursue more just outcomes in environmental decision-making. It has led the State of Michigan in developing the Michigan Environmental Justice Screening Tool, an interactive mapping tool that identifies Michigan communities that may be disproportionately impacted by environmental hazards. The map will allow users to explore the environmental, health, and socioeconomic conditions within a specific community, region, or across the entire state.

The OEJPA is also working directly with partners in individual communities, including a new pilot to build a Community Resiliency Plan in the 48217-zip code in Southwest Detroit. And the office coordinates initiatives with Michigan's tribal governments, like the Michigan Wild Rice Initiative, which brings together specialists and managers from all 12 federally recognized tribes, multiple state departments and federal agencies, and others to share information, coordinate approaches, and elevate awareness about wild rice conservation and restoration.

environmental justice communities in close collaboration with existing bodies like the MAC-EJ. In addition, the OCE will ensure robust engagement with tribal governments continues through the existing tribal consultation process.

Invest in workforce and a just transition

As we transition to a decarbonized economy with more efficient buildings, increased renewable energy sources, and expanded electrified transportation solutions, Michigan must invest in our workforce. We need to be prepared to capture new, good-paying jobs for Michigan workers and support those who may need to transition as the economy changes. Michigan is committed to ensuring no Michigan workers get left behind.

In 2020, Governor Whitmer launched the Energy Transition Impact Project (ETIP) under the leadership of the Department of Treasury. ETIP is designed to identify communities that will be impacted by the changes to the mix of energy production facilities in Michigan. The program works directly with those communities and workers to minimize impacts from a facility closure, including the loss of employment, property tax revenues, and related community services. Comprehensive transition strategies are developed to reposition communities for future economic development, high-paying jobs, new infrastructure investments, housing improvements, and other needs identified by local leaders and residents.

In addition, to support worker transitions and keep Michigan competitive for the clean energy jobs of the future, State of Michigan programs expanded their focus on high-quality workforce development, job training, pre-apprenticeship and apprenticeship, and joint labor management trainings for in-demand clean energy jobs. And, to make sure there is a demand for graduates of these programs, the Plan includes business development, retention, attraction, and other supports for minority-owned businesses in the clean energy industry. It is critical that workers who may be displaced by the energy transition—and residents who have been disproportionately impacted by climate change—are able to take advantage of new clean energy job opportunities.

Clean the Electric Grid

In 2019, Michigan's power sector contributed approximately 30 percent of Michigan's total GHG emissions. In 2020, coal and natural gas, the two primary sources of GHG emissions in the power sector, provided 59 percent of all electricity generation in the state. To meet our climate goals, Michigan will need to increase the adoption of wind and solar generation, increase energy waste reduction, invest in grid infrastructure and planning, and ensure that all of these actions are done in a manner aligned with environmental justice.

Key Strategies

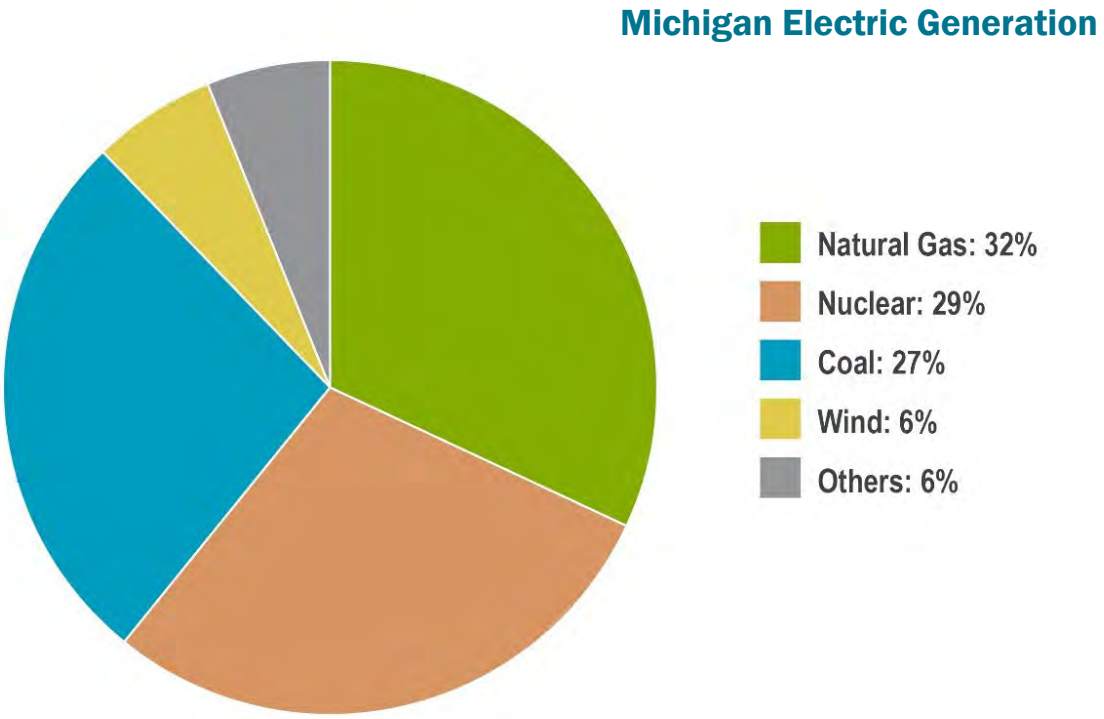
- **Clean energy resources** – Generate 60 percent of the state's electricity from renewable resources by adopting a renewable energy standard of 50 percent by 2030, supporting voluntary utility green pricing programs, and creating more favorable conditions for customer-sited behind-the-meter distributed energy resources like rooftop solar. Work with Michigan utilities to effectively phase out coal-fired power plants.
- **Holistic and integrated energy system planning** – Improve energy system planning by fully integrating traditional resources, transmission, distribution, new and emerging resources, and considerations related to the interdependency of electric and natural gas systems. Elevate community health impacts and equitable access to infrastructure in energy planning and investment decisions. Continue to develop and refine innovative rate designs to incent behaviors that advance clean energy goals.
- **Affordability and energy burden** – Limit energy burden from powering and heating homes to not more than 6 percent of annual income for low-income households. Increase affordability of utility services through expanded "Percent of Income Pilot Programs" and through minimum allocation levels for utility investment in low-income energy efficiency programs. Direct additional funding to the Michigan Utility Consumer Representation Fund (UCPF) to provide resources to intervenors in MPSC proceedings who represent the interests of low-income communities.
- **Siting** – Assist clean energy developers and communities in adopting best practices for siting renewable energy systems. Implement a plan to site solar on state-owned lands and properties as quickly as possible.
- **Energy storage** – Adopt a statewide storage target to deploy 4,000 Megawatt (MW) of grid scale storage by 2040 with a short-term target of 1,000 MW by 2025 and a medium-term target of 2,500 MW by 2030. Increase consideration of energy storage resources in utility Integrated Resource Plans through accurate modeling.

Background

To reach our climate-related goals, attract clean energy jobs, and drive down costs for Michiganders, rapid and comprehensive action is needed in the electricity sector. In fact, bolder action is particularly wise here—relative to other sectors—because of the cost-effective and scalable nature of decarbonizing the electricity sector.

This Plan's recommendations prioritize five key strategies for transforming the electricity sector: accelerating the adoption of renewable energy like wind and solar; retiring coal and other fossil fuels; investing in energy waste reduction measures that drive down costs for Michiganders; improving infrastructure and planning to ensure resource adequacy; and making sure all efforts are done with environmental justice in mind.

It is important to note that energy waste reduction is a key strategy in the electricity sector, but it is addressed more robustly in the "Repair and Decarbonize Homes and Businesses" section of the Plan.



Drive Adoption of Renewables

Michigan's progress over the last decade has shown that an economy powered by clean, renewable electricity is not only possible but increasingly preferred. Currently, renewable energy generates about 11% of Michigan's total in-state electricity. As deployment has increased and the wind, solar, energy storage, and related industries have scaled up, the cost of renewable energy has continued to fall. According to the MPSC, it cost energy providers an average of $64.48 per megawatt hour to purchase renewable energy in the period from 2009 to 2020. However, in some cases, recent contracts have dropped in cost by more than 35 percent, thus making them significantly less expensive and more stable for major energy providers than non-renewable resources.

Nearly all of Michigan's electric utilities have made individual commitments to reduce carbon emissions, with some utilities pursuing levels of renewable energy deployment beyond what is required under the state's existing mandates and goals. They are also retiring their fleets of aging coal-fired plants. According to utility retirement schedules, just one coal-fired power plant is scheduled to continue operating after 2028.

Despite this progress, Michigan will need a massive scaling up of renewable energy to achieve 60 percent renewable energy penetration this decade and reach carbon neutrality by 2050. To reach that 2030 target, Michigan must adopt a renewable energy standard of 50 percent by 2030 through the passage of legislation or via formal commitments from Michigan's utilities in proceedings before the Michigan Public Service Commission. As a demonstration of the feasibility of that standard, Michigan's investor-owned utilities already have plans in place to dramatically scale up their renewables. Taking solar for example, DTE intends to have at least 10 million panels in its generation mix by 2040, and Consumers Energy is planning for 8,000 MW built by the same year.

While a 50 percent renewable energy standard serves as a foundation, higher levels of renewable energy penetration will be necessary to achieve our goals and customer-enabled renewable energy will play a central role in additional gains. In Michigan and across the country, large companies and customers are helping to drive the increased adoption of renewable energy through tools like voluntary green pricing programs, customer-sited distributed energy, community solar, demand response, battery storage, and more. By encouraging the most-cost effective investments in clean energy resources for all energy customers, including supporting customer-sited resources, we can increase options for customers to participate in the fight against climate change and make our electric grid more resilient.

Of course, adoption of renewable energy on the scale necessary to achieve our goals will require Michigan to responsibly locate wind, solar, and storage in communities across the state. Local siting challenges have been well documented as a limiting factor in Michigan's path to reaching carbon neutrality. Through Michigan's Catalyst Communities program and tools like EGLE's Renewable Energy Ordinance Database, the state will expand support for local units of government to adopt best practices for siting renewable energy systems within their communities.

Transition away from fossil fuels

Retiring coal facilities on an accelerated timeline is fundamental to reaching Michigan's near-and long-term climate objectives. The Plan recommends that Michigan complete its transition away from coal-fired generation for powering our homes and businesses no later than 2030. It also calls for energy planning that will include options for reducing reliance on natural gas and other pathways for decarbonizing the electricity sector that go beyond coal plant retirement. As this transition takes place, Michigan must invest in support systems for workers displaced from fossil-fuel-powered generation facilities and ensure resource adequacy through investments in new generation assets and improved transmission, distribution, and storage.

Ensure resource adequacy through investments in infrastructure and planning

Building on the current IRP process at the MPSC—established with the passage of the 2016 energy laws—Michigan is well-positioned to undertake a comprehensive energy planning process to ensure reliability, affordability, and the cost-effective integration of new technologies as the sector decarbonizes. Comprehensive energy planning includes rate design, traditional resource planning, long-range transmission planning, distribution planning, storage planning, consideration of new and emerging resources, planning around areas of interdependency between the electric and natural gas systems, consideration of community and health impacts, and identification of viable decarbonization pathways aligned with carbon neutrality by 2050.

To help ensure reliability and affordability for ratepayers while we decarbonize this sector, Michigan must continue to invest in transmission and distribution infrastructure and maintain existing clean energy and energy storage assets. In addition, Michigan must invest more robustly in grid scale energy storage through a deployment target of an additional 2,500 MW by 2030 and 4000 MW by 2040.

Ensure affordability and justice

Energy burden is the percentage of household income that a given household spends on home heating and electricity costs. Energy burden is often much higher in low-income households, where residents may be unable to afford energy efficiency upgrades to their existing homes or the purchase of more expensive homes that are already energy efficient. For example, in 2018, households with an income between 0-30 percent of the state median had an average energy burden of 24 percent, compared to an average energy burden of 2 percent for households with an income at or above the state median. Michigan must develop and expand utility programs to ensure no low-income household is paying more than 6 percent of their annual income on energy. As these programs are developed, Michigan should increase funding to the UCRF, which is overseen by the Utility Consumer Participation Board, with the express intent of allowing for more participation from disadvantaged communities in the design of these programs.

Electrify Vehicles and Increase Public Transit

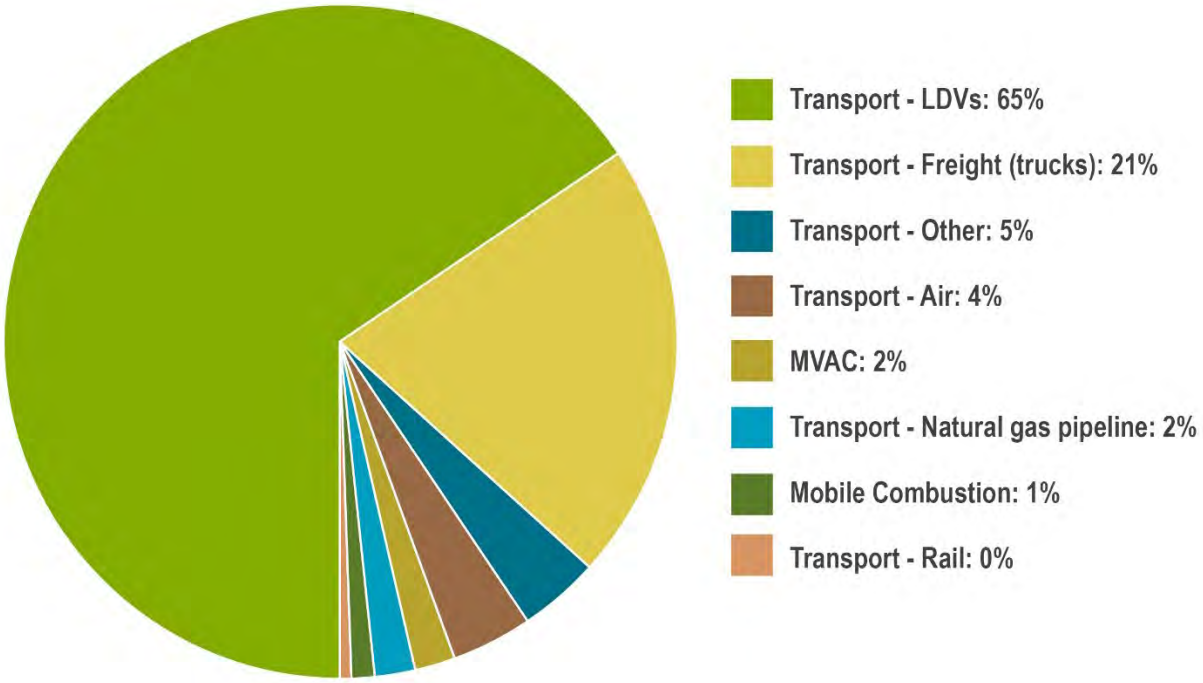
As of 2019, Michigan's transportation sector accounted for almost 28 percent of the state's total GHG emissions, the second highest emitting sector after the power sector. Transportation emissions are primarily due to the combustion of petroleum products such as gasoline and diesel in light-duty vehicles and freight trucks.

It will take a broad, all-options approach to transportation to put Michigan on track to achieve its decarbonization goals, increase equity, and offer new economic opportunities to Michiganders. To decarbonize how Michiganders move, Michigan will need to drive a rapid transition to cleaner fuels and electrification, make unprecedented investments in electric vehicle charging infrastructure, increase access to diverse transportation options, and focus on integrated people- and planet-focused transportation planning.

Key Strategies

- **Purchase incentives** – Create and fund an incentive program for the purchase of electric vehicles and at-home charging stations. Explore incentives for products like electric off-road vehicles, electric recreational vessels, and e-bikes.
- **Electric vehicle charging** – Build the infrastructure necessary to support two million electric vehicles on Michigan roads by 2030. Leverage the success of the Charge Up Michigan program to equip Michigan with a comprehensive, accessible network of chargers using various financing tools, including public funding opportunities and public-private partnerships.
- **Electrified fleets** – Transition the State of Michigan's fleet to 100 percent zero-emission vehicles. Fund and support local governments and small businesses with fleet transitions and work with schools to quickly electrify school bus fleets, with a prioritization on communities with high levels of air pollution.
- **Clean Fuels Standard** – Adopt a Clean Fuels Standard (CFS) to reduce the carbon intensity of every fuel in use.
- **Transit and diverse transportation options** – Increase access to clean transportation options – from public transit to electric vehicles – by 15 percent each year. Work with communities that are mobility insecure to set community-specific targets to expand access to clean transportation options. Increase investment in more efficient, cleaner public transit systems—as well as bike paths, walking trails, and other such infrastructure—to offer the broadest possible range of options to residents.
- **Transportation planning** – Implement a Safe Systems Approach in transportation planning to work towards the elimination of fatal and serious injuries for all road users. Develop a transportation strategic plan focused on electrification to guide state agencies in moving Michigan toward our cleaner mobility future. Consider creation of a statewide electrification plan for transit.

Transportation Greenhouse Gas Emissions by Sub-Sector Source



Background

For over a century, Michigan has enjoyed global automotive leadership. To remain at the forefront, the State needs to lead on the transition to electric vehicles, invest in infrastructure, support the retraining of our transportation workforce to ensure all workers transition into new high-paying jobs, and provide an attractive business environment for our auto industry.

While vehicle electrification is a key technology needed to meet 2050 decarbonization goals for the transportation sector, it cannot be the only decarbonization solution for Michigan. Michigan needs to employ multiple strategies and effective planning to achieve our state's transportation decarbonization goals and mobility needs as the transition to electrification unfolds over time.

Transition to cleaner fuels and electric vehicles

Electric vehicles represent a small fraction of Michigan's current auto sales today. Just 0.62 percent of all vehicles sold here in 2020 were electric. Two of the key current barriers to widespread uptake are the higher purchase cost typically associated with these vehicles and the real or perceived lack of electric vehicle charging infrastructure.

To address these challenges, the State of Michigan will develop purchase incentives targeted to spur sales of electric vehicles throughout Michigan, particularly in the near-term to stimulate market growth and help more Michiganders access clean transportation options. To lead by example on this path, the State of Michigan will transition its fleet to 100 percent zero-emission vehicles by 2035 for light-duty vehicles and 2045 for medium- and heavy-duty vehicles. Leveraging this leadership, the State will also expand funding options for fleet conversions for local governments, small businesses, and school bus fleets, with a prioritization on communities with high levels of air pollution.

To build out the necessary charging network, Michigan will expand funding opportunities for direct current fast charging stations to make sure that Michigan residents can drive an electric vehicle throughout the state without anxiety over where to get their next charge. Through Charge Up Michigan, the State has already invested more than $45 million in charging infrastructure and will spend millions more in the coming years thanks to the recent and forthcoming influx of additional federal resources. By expanding funding through the Charge Up Michigan program and partnering with utilities and the private sector, Michigan will deploy enough charging infrastructure to support two million electric vehicles on Michigan roads by 2030. In pursuing that 2030 target, Michigan should aim for electric models to account for at least 50 percent of light-duty vehicle sales, 30 percent of medium- and heavy-duty vehicles sales, and 100 percent of public transit vehicles and school buses sold that year.

Michigan should also pass legislation to adopt a CFS, a technology-neutral, performance-based policy to reduce the carbon intensity of transportation fuels. These standards ratchet down carbon emissions in the transportation sector over time, increasing the use of lower-carbon fuels and reducing the use of higher carbon fuels. By setting a standard that grows more stringent over time, the program will dramatically increase private investment in lower carbon fuels. While providing added encouragement and support for the emerging electrified transportation sector, this policy can also incentivize the use of lower-carbon liquid fuels in non-electric vehicles during the transition to a fully electric future. In addition, a CFS can be designed to create revenue for reinvestment in electric vehicle purchase incentives or charging infrastructure. This policy is a critical bridge between the status quo's carbon-intensive fuels and electrification.

Increase access to diverse transportation options

Vehicle electrification cannot be the only transportation decarbonization solution for Michigan. Vehicle fleets have inherently slow turn-over rates. The vast majority of vehicles on Michigan's roads will still be burning gasoline in 2030, even if we adopt the market incentives recommended in this Plan and automakers aggressively pursue their electric vehicle sales goals. In light of this reality, Michigan needs to employ multiple strategies to achieve our transportation decarbonization goals as the transition to electrification unfolds over time. Expanding access to safe and convenient public transit, mobility solutions like car sharing, and high-quality bike and walking infrastructure will play a vital role in decarbonization.

Better and more widely available transit also represents an opportunity to advance equity. It increases access to opportunities to learn, earn a living wage, and remain healthy for the many Michigan families that currently lack reliable transportation. Almost eight percent of Michigan households have no vehicle at all, and that number more than doubles to 19 percent for renters. Nearly 3 out of every 5 jobs cannot be reached by public transit, meaning that these opportunities are not equitably accessible to all Michigan families. This is particularly true for non-white households, which make up 79 percent of transit riders. Public transportation is also the best transportation option—and in some cases the only viable one—for many seniors and Michiganders with disabilities. This Plan sets goals to diversify transportation options and increase investments in public transit and related mobility solutions.

Implement people and planet focused transportation planning

Strategic transportation planning will help knit traditional and advanced transportation options into an integrated system that serves all Michiganders equitably. As Michigan develops a statewide electrification plan and related tools to do just that, coordination will be critical given the many key players involved, including local, state, and federal agencies and a great variety of private partners.

The Plan also recommends the implementation of a Safe Systems approach to transportation planning that focuses on safe mobility for all road users. Implementing the Safe System approach means anticipating and proactively planning for road user mistakes through the design and management of road infrastructure and the development of rules and regulations for drivers that lower the risk of death or serious injury.

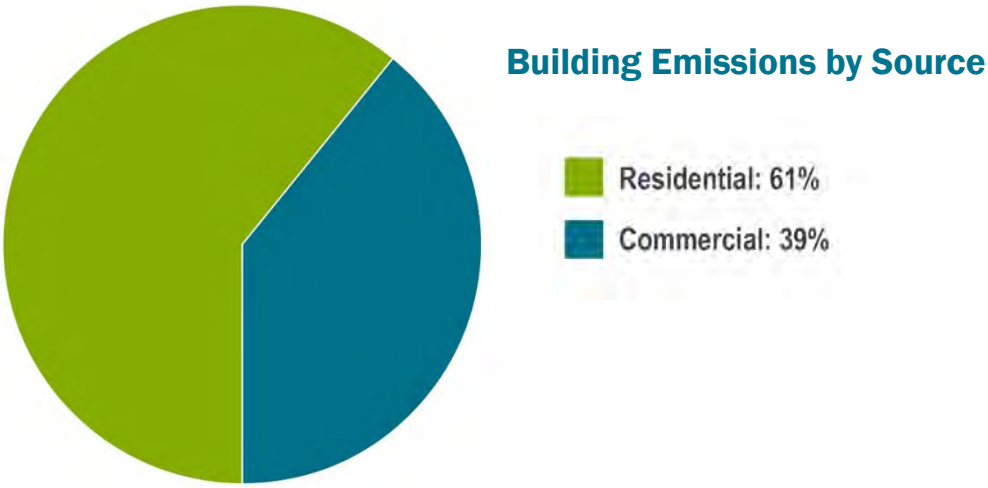
Repair and Decarbonize Homes and Businesses

As of 2019, Michigan's buildings accounted for almost 18 percent of the state's total GHG emissions, the third highest emitting sector after the power and transportation sectors. While Michigan's buildings use a significant amount of electricity for lighting, appliances, air conditioning, ventilation, and other purposes, those emissions are accounted for in the electric generation sector. Emissions related to the built environment are primarily due to use of heating fuels such as natural gas, propane, and oil.

In addition to its pivotal role in achieving our climate goals, investing in our building stock will help lower utility and other costs for working families and small businesses, make our homes and workplaces healthier, and expand economic opportunities across the state. Decarbonizing our buildings will require baseline investments in repairing Michigan's homes; stronger requirements, incentives, and financing options for energy efficiency and waste reduction; and evaluation and adoption of innovative home heating alternatives, including electrification in immediately cost-effective use cases.

Key Strategies

- **Heating Michigan homes and businesses** - Reduce emissions related to heating Michigan homes and businesses 17 percent by 2030. Focus on both public and private-sector investments and targeted efficiency and assistance programs to reduce the energy burden for low-income residents.
- **Clean financing opportunities** – Explore programs, financing options, and public funding opportunities – including the allocation of funds to the state's nonprofit green bank, Michigan Saves – to help families, small businesses, and schools invest in clean energy projects from weatherization to renewables and building decarbonization. Adopt and promote utility on-bill financing and property assessed clean energy programs (PACE). Identify sources of consistent, ongoing funding to address homes that are ineligible for weatherization assistance.
- **Building codes and climate readiness** – Adopt the 2021 Model Energy Code with provisions to support electric vehicle charging and consider incorporation of additional climate mitigating solutions such as energy storage, renewable energy, and building decarbonization.
- **Energy waste reduction programs** – Increase utilization of cost-effective opportunities to reduce energy waste. Achieve at least 2% annual electric energy efficiency savings by increasing the current energy waste reduction target for electric utilities and maintaining the corresponding incentives for exceeding statutory minimums. Restore the energy waste reduction target for municipal and cooperative electric utilities. Increase energy waste reduction (EWR) for natural gas utilities to a minimum of 1.5% annual savings with enhanced cost-effective incentives for exceeding statutory minimums. Work to ensure energy efficiency is on a level playing field with supply-side resources (i.e., power generation) in the MPSC integrated resource planning (IRP) process which guides the financial investments of Michigan utilities. Explore additional pathways to reduce energy demand and energy burden.
- **Incentives for energy efficient appliances** – Establish incentives for the sale of electric appliances that yield immediate energy and cost savings, particularly for low-income Michiganders.
- **Evaluate gas system regulatory and policy options** – Undertake a pathway analysis to assess options to reduce carbon intensity in the built environment.



Background

To reach our 2030 goals of reducing emissions relating to heating Michigan homes and businesses 17 percent by 2030, Michigan must reduce end-use emissions related to heating Michigan homes and businesses by approximately three percent per year from now to 2030. We will accomplish this objective through investments in energy conservation, energy efficiency, smart consumption, cogeneration, and replacing traditional fossil fuel use with cost-effective technologies that rely on electricity and alternatives like renewable natural gas and hydrogen.

Half of Michigan homes are less than 50 years old. With adequate care and maintenance, most will remain in use through and beyond 2050. While the other half of Michigan homes are more than 50 years old, most can be expected to last another 50 years or more with modest investments. However, many of these buildings are inefficient and rely on fossil fuels for heating and appliances like gas stoves. They will require significant upgrades to be fully decarbonized.

Energy efficiency and weatherization investments targeted at Michigan's most inefficient buildings will drive significant investments in Michigan's most disadvantaged communities. Unfortunately, not every home is ready for energy efficiency and weatherization upgrades. Many of Michigan's most inefficient buildings need a new roof or upgrades to remove carbon monoxide from the home before they can qualify for many available funding programs. In fact, 25 percent of all weatherization projects across the state are deferred due to structural challenges. This barrier is even higher in older communities like Detroit where deferral reaches nearly 75%. Michigan must increase investments in home repairs and streamline access to energy efficiency and weatherization funding programs for communities with aging housing stocks. This is a pre-requisite to decarbonizing our building sector and achieving our short- and long-term GHG reduction goals.

Reduce energy waste

Under Michigan law, electricity providers must achieve annual EWR of one percent per year (based on total annual retail sales of the prior 12 months) and gas providers must hit 0.75 percent. In addition, Michigan law provides financial incentives for energy providers to meet or exceed those standards. In just over a decade, these policies have resulted in a lifetime savings of nearly $1.2 billion for electric and gas customers. When it comes to reducing emissions—and saving money for Michigan families and businesses—it is hard to get more bang for the buck than cutting energy use.

Building from their success thus far, Michigan should strengthen existing EWR programs for investor-owned utilities – doubling the energy waste reduction target for electricity to two percent and bumping it up to 1.5 percent for natural gas. The state should also restore the EWR targets for municipal and cooperative electric utilities. In taking these steps, we must create and leverage incentives for over-performance and encourage robust consideration of EWR alongside power generation in IRPs.

Building new, clean buildings

While Michigan's existing homes and buildings will account for most of the GHG emissions in this sector from now through 2030, we must work to ensure that all new residential and commercial buildings are as efficient as possible, use materials with a low carbon footprint like mass timber, and prepare for new technologies. To help make this possible, Michigan must adopt the 2021 Model International Energy Conservation Code for new buildings. Michigan should also expand on the model code to include provisions to support electric vehicle charging and consider the incorporation of additional climate mitigating solutions such as energy storage, renewable energy, and building decarbonization.

Rethink how we heat our buildings

Moving forward, Michigan should consider and evaluate alternatives to current strategies for heating Michigan's buildings. According to research from Rewiring America, at least 39 percent of Michigan households—or 1.5 million households—could save a total of $710 million a year on energy bills if they were using modern heat pump space heaters and heat pump water heaters instead of their current appliances, which use electric resistance, fuel oil, or propane. That's an average savings per household of $460 each year. Half of the households with immediate savings potential are considered low- and moderate-income. The switch to electric heating and other appliances may also yield health benefits, such as helping to reduce the risk of respiratory symptoms associated with gas stove use. To make heating less carbon-intensive, Michigan should establish incentive programs for electric appliances and heat pumps for use-cases that will save customers money today, with an emphasis on energy burden relief for low-income residents.

To complement immediate policy actions, the Plan recommends the state undertake a pathway analysis to assess options to achieve carbon neutrality from natural gas production, transmission, distribution, compression, storage, and end uses in a least-cost manner. This analysis should consider a full range of options for decarbonizing natural gas end uses, including energy efficiency, electrification, fuel switching to renewable natural gas and hydrogen, and other potential opportunities.

Increase financing

To facilitate home repairs, energy efficiency investments, and electrification, Michigan should also expand direct state investments and customer-facing financing options. By supporting programs like on-bill financing and property assessed clean energy (PACE), Michigan can create easier access to capital at better terms for customers and attract more private sector capital to the building decarbonization challenge.

Drive Clean Innovation in Industry

As of 2019, Michigan's industrial sector accounted for 15 percent of the state's total GHG emissions, the 4th highest emitting sector after the buildings and housing sector. While aggregated together in tracking emissions, the state's industrial sector is remarkably diverse, and makes products like chemicals, iron, steel, cement and food using specific manufacturing processes that can cause on-site GHG emissions, often require a lot of power, and/or involve GHG emissions in their supply chains.

Decarbonizing these sectors will require process-specific solutions with a focus on advancing research and development, improving facility efficiency, using cleaner products and fuels, and developing new markets for byproducts.

Key Strategies

- **Buy clean, buy Michigan** – Strengthen public and private-sector procurement programs to favor the use of low-carbon and circular-economy products and identify opportunities to support disadvantaged businesses in procurement. Encourage the production and purchase of materials made by Michigan workers.
- **Recycling and waste** – Triple the state's recycling rate to 45 percent and cut food loss and waste in half by 2030. Expand on efforts like 'Next Cycle' to develop markets for recycled materials.
- **Shared clean industrial innovation** – Encourage clean innovation hubs to collaborate on the development and deployment of new, cleaner manufacturing technologies and reduce emissions from hard to decarbonize industries. Work to ensure that Michigan communities impacted by industrial development and operations are meaningfully engaged in the siting, construction, and operation of clean innovation hubs.
- **Clean industry process improvements** – Provide incentives and technical assistance to advance the energy efficiency and other process improvements necessary to achieve carbon neutrality in the industrial sector by 2050. Deploy combined heat and power (CHP) in new facilities and convert existing facilities to renewable energy or lower-carbon fuels such as biogas, renewable natural gas or biomethane, and clean hydrogen.
- **Carbon capture, utilization, and sequestration** – Explore the use of carbon capture, utilization, and sequestration in industrial applications where eliminating the use of fossil fuels is impossible or cost-prohibitive and for entities attempting to go carbon negative in their operations.

Background

Michigan's industrial sector represents one the state's greatest strengths on the path to carbon neutrality. Michigan has the 5th largest advanced manufacturing workforce in the country, with more than 65,000 workers employed in that sector in 2019. The state is a national leader for employment in industries related to Industry 4.0 and automation. Of the top 100 automotive suppliers to North America, 96 have a presence in Michigan and 71 are headquartered here. The state is home to nearly 19% of all U.S. auto production, more than any state in the nation.

This unparalleled industrial heritage and the technological know-how of our workforce positions Michigan well to develop and manufacture the next generation(s) of innovative products that will be used in every sector of our economy to unlock new decarbonization strategies. To make Michigan the trailblazing home for the low-carbon inventions of tomorrow—and create the corresponding opportunities for sustained economic growth and job creation—the state will need innovative market development and regulatory programs and strong financial incentives.

In addition to manufacturing the products needed to decarbonize other sectors, Michigan's industrial sector has already taken significant steps in reducing GHG emissions from its operations. Between 2005-2018, the industrial sector cut their emissions by 5.9 million metric tons – or more than 23 percent. Additional analysis suggests that the industrial sector has the potential to reduce their annual emissions by an additional 5.7 million metric tons by 2030 – a reduction of more than 45 percent when compared to 2005 levels.

Efficient facilities

Energy efficiency is a vital tool that can help Michigan's industrial sector reduce GHG emissions while keeping energy costs reasonable. Importantly, industrial energy efficiency and process improvements may be able to reduce local air pollution in communities located near industrial facilities and can create new workforce opportunities conducting energy audits and implementing the energy saving strategies they identify.

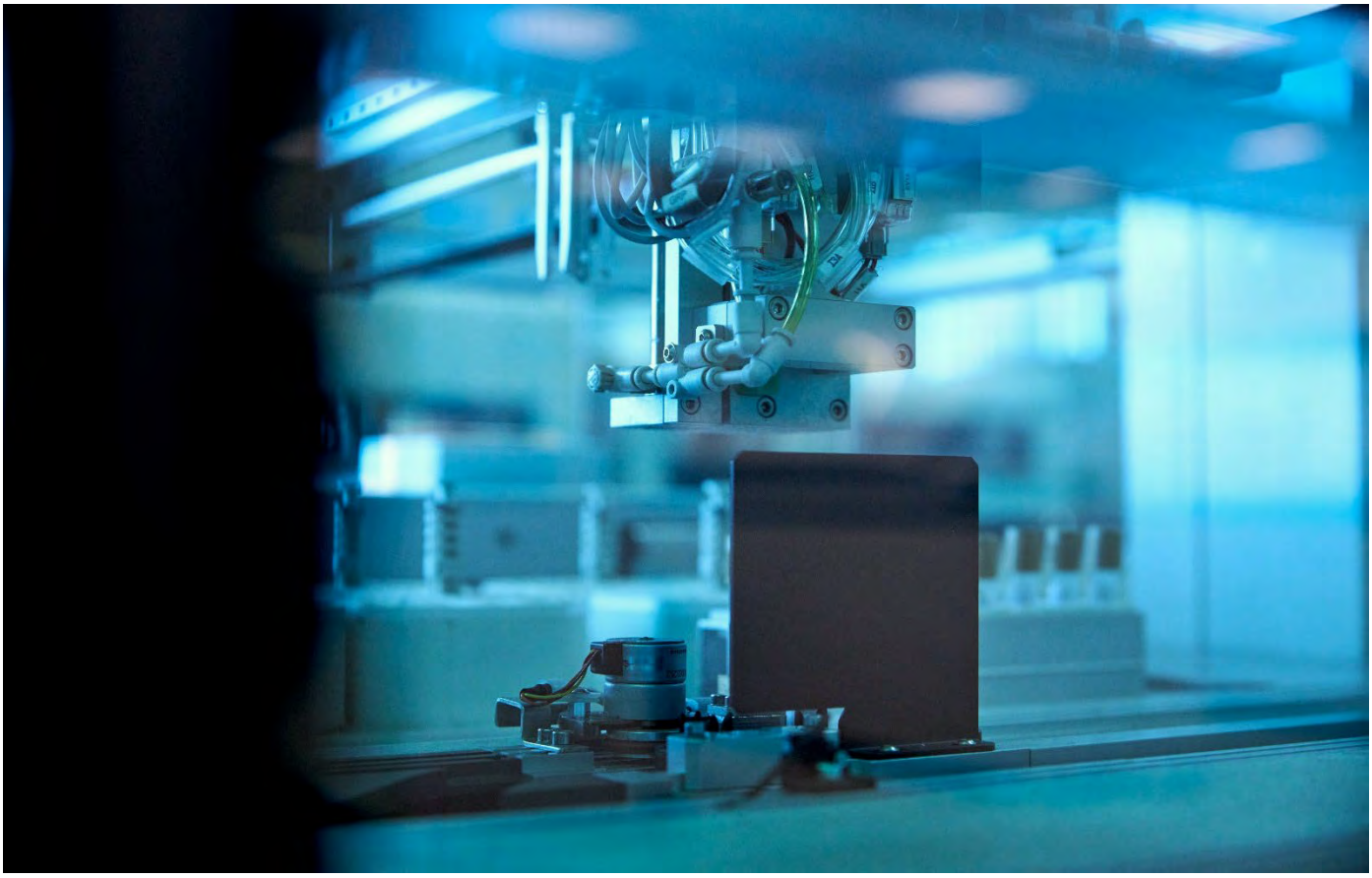
A key efficiency opportunity exists around CHP, which is a process that takes excess heat from an industrial process or facility and uses it to generate electricity. CHP is the most fuel-efficient way to produce and utilize both electric and thermal energy from a single fuel source. In 2018, the Michigan Energy Office released its CHP Roadmap for Michigan, which recommended an optimal level of additional CHP deployment in Michigan ranging from 722 MW to 1,014 MW by 2030. The next wave of CHP applications will enable deeper decarbonization of the industrial sector through the use of renewable energy or lower-carbon fuels such as biogas, renewable natural gas or biomethane, and hydrogen.

Cleaner products

Michigan is well-positioned to grow its circular economy—a systems approach that emphasizes growing markets for recyclable materials so they are (re)used by Michigan workers and business to make new products, rather than taken to landfills or other disposal facilities. For example, EGLE's 'Next Cycle' program works with businesses to incubate ideas that grow Michigan's recycled materials supply chain and end markets. The Plan identifies a number of opportunities to further spur market demand for cleaner products, such as lower-carbon cement for use in infrastructure projects. It also calls for expanding public and private sector clean procurement programs.

Clean innovation hubs

While some decarbonization solutions already exist today, many are still waiting to be innovated. As home to many energy-intensive industries, Michigan is well-positioned to lead the way on industrial decarbonization solutions. Clean innovation hubs can help Michigan's industrial sector achieve GHG emissions reductions as cost-effectively as possible through shared infrastructure, the strategic co-location of industrial facilities, and the efficient use of materials and energy streams. Individual clean innovation hubs could focus, for example, on hydrogen technologies or electric vehicle battery recycling. Safeguards must be put in place to address any public health and environmental justice concerns with these facilities. Potentially impacted communities should have the opportunity for adequate consultation in the siting, construction, and operations of any innovation hub.



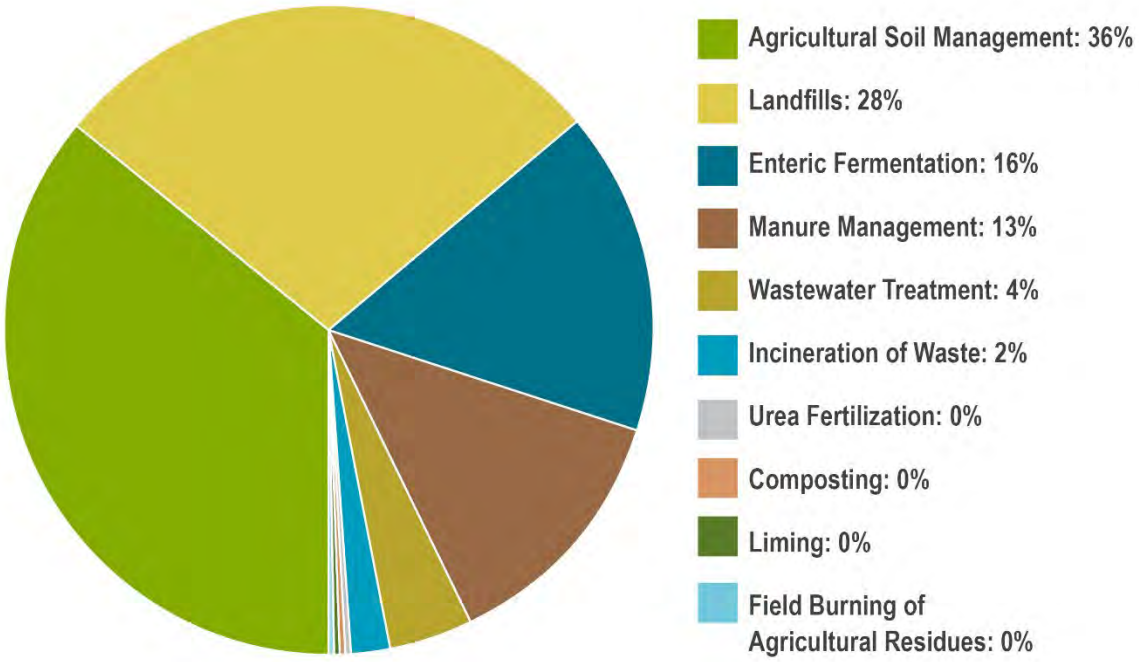
Protect Michigan's Land and Water

As of 2019, Michigan's natural and working lands accounted for nine percent of the state's total GHG emissions, contributing the smallest percentage of overall emissions from an individual sector. These emissions come primarily from agricultural practices and land-use changes. To drive decarbonization and sequester carbon in Michigan's natural and working lands sector, it will be crucial to protect and conserve Michigan's natural resources and support innovative solutions in agriculture.

Key Strategies

- **30 x 30** – As a part of the national 'America the Beautiful' initiative, protect 30 percent of Michigan's land and water by 2030 to naturally capture GHG emissions, while maintaining and improving recreational opportunities for all Michiganders, expanding access in disproportionately impacted communities, and protecting biodiversity.
- **Wetlands, waters, soils, forests** – Avoid land-use conversion that causes a net increase in GHG emissions and prioritize land uses that reduce GHG emissions. Protect and restore existing wetlands and waterways and create new wetlands where appropriate. Adopt policies to protect the state's soils and enhance their capacity to capture and store carbon. Maintain and develop healthy forests across public and private lands. Support and promote tools that expand the use of the mass timber as a sustainable building material.
- **Treaty rights** – As conservation efforts move forward, the state will not interfere with treaty rights, treaty resources, and tribal cultural resources and will consult with Tribal Nations. Conservation efforts must respect the exercise of treaty rights.
- **Farm management and practices** – Develop initiatives to support farmers in adopting best management practices to improve soil health, store carbon, and utilize other greenhouse gas emissions, while also protecting water quality. Create programs to catalyze and accelerate the transition to cleaner technologies like electric and hydrogen fuel-cell farm equipment.
- **Michigan grown products** – Fund programs like the 'Buy Michigan Agriculture Campaign' to encourage the purchase of Michigan grown and raised products, address food insecurity challenges, and counter supply chain issues.

Agriculture and Waste Emissions by Source



Background

From birdwatching, hunting, and camping to the timber and forest products that are used in our homes and businesses, our lands, waters, and forests are essential components of what makes Michigan, "Pure Michigan."

The lands and waters we call Michigan today are the ancestral territories of the Anishinaabe, who have lived in the State of Michigan from before recorded history to present day. The Anishinaabe people's commitment to this place should encourage us to be better stewards of the land we inhabit and the waters on which we depend.

The Michigan Department of Natural Resources manages 4.6 million acres of public lands, 3.86 million of which are forested, and the state contains roughly 5.5 million acres of wetlands. Michigan is also home to over 50,000 farms. If protected and appropriately managed, Michigan's natural and working lands can store and sequester carbon and offer additional benefits including limiting water runoff pollution, providing habitats that support biodiversity, and reducing the impacts on Michigan communities from more frequent and intense flooding, extreme heat, and other effects of climate change. These lands are critical to our economy and the health of all Michiganders.

Michigan's natural resources and land use

Michigan's forests currently store approximately 537 million tons of live tree carbon and 2,045 million tons of total forest ecosystem carbon, and they continue to sequester additional carbon from the atmosphere with each passing day. Sustainable forest management is key to maintaining and expanding the role of forests in reducing carbon emissions – and avoiding the loss of important carbon sinks that would make Michigan's path to carbon neutrality even more challenging.

In addition, sustainable forestry can encourage responsible sourcing and recycling of forest products. Building out a sustainable forestry and forest product industry can create thousands of good-paying jobs for Michiganders, capture new economic development opportunities, and provide sustainable building materials like mass timber.

Many of the state's powerful natural carbon sinks have been developed or converted and lost their natural ability to store carbon, increasing net GHG emissions. Wetlands, in particular, are important carbon sinks and stocks. Building out green waterway infrastructure, like constructed wetlands, can yield both climate adaptation and mitigation benefits. This Plan recommends avoiding further land-use conversions that increase GHG emissions and stewarding Michigan's natural resources by implementing land-use strategies that reduce GHG emissions in partnership with Michigan's tribal governments.

The federal government signed several treaties with tribal nations in Michigan, which reserved hunting and fishing rights for tribal members. Working with and supporting tribal nations will be an essential component of managing natural and working lands in a way that respects and does not interfere with treaty rights, treaty resources, and tribal cultural resources.

Soil health and innovation in agriculture

Michigan is the second most agriculturally diverse state in the country. The state is home to nearly 50,000 farms, spanning over nine million acres of agricultural land. These lands have an opportunity to sequester carbon, but many agricultural practices also emit it. This Plan recommends solutions to implement best practices for managing working lands to restore soil health and store carbon, provide low-carbon equipment to farmers, increase access to locally sourced agriculture, and reduce food waste.

Promoting climate-smart strategies like cover crops, conservation tillage, and precision agriculture can improve soil health, store carbon, improve water quality, and reduce fertilizer needs. Biochar and compost also have the opportunity to reduce both food waste and reliance on synthetic fertilizers. Innovative animal feed mixes and additives can be used to reduce GHG emissions from livestock.

Across the state, there are communities that lack access to healthy, high-quality food. As we transform our agricultural sector to mitigate and adapt to climate change, we must also take that opportunity to ensure that everyone can get the food they need to live healthy lives. Supporting Michigan-grown agriculture, urban agriculture, and farmer's markets by funding programs like the 'Buy Michigan Agriculture Campaign' can promote healthy local food systems and reduce emissions from transporting food.

While some solutions are apparent for Michigan's working lands, additional funding opportunities, research, and technological advancements will be necessary to understand how to fully decarbonize this sector in a way that balances the needs of farmers, ecosystems, and all Michiganders.

LEADING BY EXAMPLE IN STATE GOVERNMENT

State governments have a variety of tools in their purview to address climate change. For example, state agencies use energy, procure or purchase vehicles and other goods/services, and make a wide variety of other investments in our communities and economy. Decisions and actions in these and other areas are opportunities for the State of Michigan to show the way to carbon neutrality.

In 2019, the governor's office launched an interdepartmental workgroup to identify opportunities for state government to lead by example and use administrative powers to reduce GHG emissions. This work focused on how the state could incorporate climate mitigation into existing state programs and identify initiatives that departments could pursue to accelerate the transition toward carbon neutrality. This effort demonstrated that every state department – from the Department of Natural Resources to the Department of Treasury – has an opportunity to act on climate.

In response to this work, Governor Whitmer created new offices and initiatives to help strengthen climate action across state government, including the Energy Transition Impact Project at the Department of Treasury and the Office of Future Mobility and Electrification at the Department of Labor and Economic Opportunity (LEO). The leaders of these programs collaborate closely with their colleagues in the Office of Climate and Energy and Office of Environmental Justice Public Advocate, which Governor Whitmer created at EGLE as one of her first acts in office to lead carbon reduction, just transition, and environmental justice efforts.

Solar Panels at Oden State Fish Hatcher – *photo courtesy of the Michigan DNR*

This focus and planning on climate—along with the structuring of climate work directly into state agency organizational charts—has led to bold actions by the State of Michigan to reduce GHG emissions. While not an exhaustive list, the following highlights some examples of the state leading by example.

LEADING BY EXAMPLE IN STATE OPERATIONS

To reduce GHG emissions in State of Michigan operations, the Whitmer administration and state agencies have:

- Signed agreements to power state-owned facilities with 100 percent renewable energy by 2025.
- Committed to carbon neutrality in state-owned buildings by 2040.
- Pledged to reduce energy usage in state-owned facilities 40 percent by 2040.
- Established a $5 million Energy Efficiency and Green Revolving Fund to expand renewable energy and energy efficiency projects at state facilities (and proposed an expansion of this investment in the FY 2023 budget proposal).
- Developed a plan to responsibly site solar across state-owned properties.
- Upgraded state systems to deploy more efficient water use (and reuse) techniques, saving energy and thousands of gallons of water per year.
- Launched the nation's first carbon sequestration and carbon market program on state owned forest land.
- Committed to electrify the state's vehicle fleet, starting with a $10 million FY 2023 budget proposal.
- Required consideration of vendor environmental track records in the state's procurement and purchasing decisions.
- Required all state facilities to offer recycling services.
- Developed a toolkit for state agencies to review sustainability projects on state properties and ensure easy access to information on how to initiate eco-friendly practices.
- Launched a state employee education campaign around sustainability.
- Invested in backup power for all state-owned pumping stations to reduce freeway flooding events in Southeast Michigan.

LEADING BY EXAMPLE IN STATE BUDGETS

Each of the budgets Governor Whitmer has signed so far have delivered millions of dollars for strategies and investments to address climate change. Most recently, Governor Whitmer proposed an FY 2023 executive recommendation that included over half a billion dollars in climate, advanced mobility, and clean energy related funding. These proposals ranged from investments in the state green bank and building out electric vehicle charging infrastructure to the reforestation of native trees and grants to communities for climate-resilient infrastructure.

LEADING BY EXAMPLE IN STATE PROGRAMS

State agencies are also showing the way to carbon neutrality by developing new programs—and reshaping existing ones—to jumpstart progress in implementing the strategies in this Plan.

Commit to Environmental Justice and Pursue a Just Transition

- EGLE developed a Michigan-specific EJ Screening tool that provides maps and data to help Michigan move toward environmental equity. It allows users to identify where populations are more vulnerable and what challenges communities face. EGLE is also supporting the Michigan Public Service Commission (MPSC) in considering environmental justice and health impacts as a part of the utility integrated resource plan process.
- The Department of Health and Human Services published a *Climate and Health Adaptation Planning Guide for Michigan Communities* to help local units of government and their residents integrate climate and health concepts into existing community planning and decision making.

Clean the Electric Grid

- The MPSC launched MI Power Grid, a multi-year stakeholder process to maximize the benefits of clean, distributed energy resources for Michigan residents and businesses.
- The Michigan Department of Agriculture and Rural Development (MDARD) developed a policy allowing farmers to rent land for large scale solar operations while maintaining preservation of farmland by suspending and extending agreements for an equivalent number of years to properties enrolled in the PA 116 program.

Electrify Vehicles and Increase Public Transit

- The Office of Future Mobility and Electrification within LEO has led several projects to promote electric vehicle adoption and eliminate range anxiety associated with the availability of electric vehicle charging infrastructure.
- The Michigan Department of Transportation (MDOT) completed a Transportation Asset Management Plan which included analysis of risks to the department related to climate change. It has also supported external initiatives like the Southeast Michigan Council of Government's climate resiliency and flooding mitigation study to determine which infrastructure assets in southeast Michigan—including roads, bridges, culverts, and pump stations—are most at risk for flooding

Repair and Decarbonize Homes and Businesses

- The Michigan State Housing Development Authority (MSHDA) within LEO included a Green Policy within their Qualified Allocation Plan to require all its housing projects to achieve a green building certification and to add incentives for projects to achieve higher levels of sustainability commitments and energy efficiency. MSHDA's 2022 Statewide Housing Plan also includes focuses on environmental justice in housing development and rehabilitation.

Protect Michigan's Land and Water

- The DNR incorporated climate mitigation as a key pillar in their Public Land Strategy to ensure the department identified appropriate strategies for emerging, climate-based threats to natural resources, and launched the nation's first carbon sequestration and carbon market program on state forest land.

Drive Clean Innovation in Industry

- The Michigan Economic Development Corporation (MEDC) within LEO has started integrating Michigan's climate goals into its business attraction efforts and has adjusted their focus to strategic industries that support the transition to a clean energy future, including energy storage businesses, electrified vehicle manufacturers, and companies that perform research and development in these sectors.

Governor Gretchen Whitmer and EGLE Director, Liesl Clark speak at an Earth Day Event.

This broad and deep State of Michigan leadership will help spur the state's economy and catalyze rapid progress toward achieving carbon neutrality by 2050.

CONCLUSION

The realities of the climate crisis are already directly impacting Michiganders and present our state with both an existential challenge and a compelling opportunity. If we fail to act with the urgency required, the impacts of climate change will likely only get worse, disproportionately affecting those who have long borne the brunt of environmental injustice. Yet a better path exists—a bold and strategic response to the climate crisis that will reward our state with enhanced economic opportunities, good-paying sustainable jobs, affordable and reliable energy for all, and clean air and water for every Michigander.

The steps to achieving this vision are within reach, though urgent action is needed. This MI Healthy Climate Plan lays out in detail the steps we need to take immediately to achieve a 52 percent reduction in GHG emissions by the end of this decade, including efforts to clean the electric grid, electrify vehicles and increase public transit, repair and decarbonize homes and businesses, drive clean innovation in industry, and protect Michigan lands and water. As we drive GHG reductions in each of those areas, the Plan calls on us to pursue environmental justice every step of the way and commit to a just transition to a carbon neutral economy for all Michigan workers and communities.

No less importantly, the Plan identifies the equally urgent actions needed now to fully decarbonize Michigan's economy by 2050, including areas where additional work and study are needed for harder-to-decarbonize sectors including buildings and housing, industry, and agriculture.

With bold leadership by example from state government and every Michigan resident and business playing their parts, we can – together – build a more equitable, just, healthy, and prosperous future and ensure that the benefits of this clean energy transition are enjoyed by all Michiganders.

IMPLEMENTATION

The State of Michigan is committed to implementing the MI Healthy Climate Plan. As directed by the Executive Order calling for this Plan, the Office of Climate and Energy within EGLE will oversee its implementation in concert with state departments and agencies, tribal and local governments, and key stakeholders. The Council on Climate Solutions and Michigan Advisory Council on Environmental Justice will provide advice, feedback, and guidance along the way. And, as required by the Order, EGLE will submit publicly available annual reports updating all 10 million Michiganders on our progress.

APPENDICES

- Workgroup summaries of Key Recommendations presented to the Council on Climate Solutions
- Michigan Advisory Council on Environmental Justice recommendations to the Council on Climate Solutions and the State of Michigan.

Appendix B: Michigan Public Service Commission's Report on Status of Renewable Energy, Distributed Generation, and Legacy Net Metering in Michigan – December 16, 2024

MPSC
MICHIGAN PUBLIC SERVICE COMMISSION

Status of Renewable Energy, Distributed Generation, and Legacy Net Metering in Michigan

December 16, 2024

Dan Scripps, Chair
Alessandra Carreon, Commissioner
Katherine Peretick, Commissioner

LARA
LICENSING AND REGULATORY AFFAIRS

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Executive Summary

This annual report combines and summarizes renewable energy activities related to the Renewable Energy Portfolio Standard (RPS) pursuant to Public Act 295 of 2008 (PA 295), as amended by Public Act 342 of 2016 (PA 342) and subsequently by Public Act 235 of 2023 (PA 235); Voluntary Green Pricing Programs (VGP); Integrated Resource Plans (IRP); Public Utility Regulatory Policies Act (PURPA); and the Distributed Generation and Legacy Net Metering Programs.[1]

For 2021, electric providers were required to retire[2] the number of renewable energy credits (RECs)[3] needed to meet the 15% RPS. 2021 was the final year of statutory renewable portfolio standard requirements until PA 235 was signed into law in 2023. PA 235 requires electric providers to maintain a renewable portfolio requirement of 15% through 2029, 50% from 2030 through 2034, and finally achieve a 60% renewable portfolio in 2035 and each year thereafter.

All of Michigan's electric providers[4] subject to the renewable portfolio standard in 2021 met this requirement.

Going back to the first renewable portfolio standard in 2008, wind generation was the primary technology used to meet the standard and currently accounts for a majority of the RECs used for compliance, but favorable economics, differences between how wind and solar capacity are accredited by the regional transmission organizations, and siting concerns in the middle of the 2010s led to solar installations emerging as the primary new selected renewable energy resource for most of Michigan's electric providers. More recently, however, certain headwinds have created additional challenges for renewable energy deployment, including continuing challenges with project siting; ongoing supply chain issues, particularly in the solar industry; and challenges associated with the interconnection queues operated by the regional transmission organizations. Taken together, these challenges have increased both the time and cost of developing projects.

While electric providers retired enough RECs to achieve the 15% renewable portfolio standard using RECs generated from 2017 to 2021, it is useful to note that based on the number of RECs generated only in 2021, Michigan's 2021 renewable energy percentage was equal to 21.6%[5] of retail sales. For 2022, Michigan's renewable energy percentage was equal to 23.3%[6] of retail sales. In 2023, almost all electric providers

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[1] Subject to Section 51 of Public Act 295, as amended, the MPSC was directed to prepare an annual report summarizing the Commission's activities related to PA 295 and electric provider's annual reports. Section 51 was repealed effective January 1, 2023. The final reports issued pursuant to Section 51 are available at the MPSC's website: https://www.michigan.gov/mpsc/regulatory/reports/legislative.
[2] Renewable energy credits are "retired" when used for compliance.
[3] The term "renewable energy credit" includes renewable energy credits, Michigan incentive renewable energy credits, and energy waste reduction credits when substituted for renewable energy credits.
[4] Through the 2021 compliance year there were 65 electric providers subject to the renewable energy standard including: 7 rate-regulated utilities, 10 cooperative utilities, 40 municipal utilities, and 8 AESs. Fifteen licensed AESs not currently serving customers are not included in this total.
[5] MIRECS vintage 2021 RECs and 2020 retail sales data were used to calculate the percentage.
[6] MIRECS vintage 2022 RECs and 2021 retail sales data were used to calculate the percentage.

voluntarily retired a total of 14,591,614 RECs for a total of 15% to meet the renewable portfolio standard. While all of the portfolio data has been submitted into the Michigan Renewable Energy Certification System (MIRECS), the total number of RECs created in 2023 is not yet finalized due to reporting lag. PA 342 extended the life for RECs generated after April 1, 2017, to five years from the previous three-year REC "banking" allowance and this continued with the amended PA 235.[7] All RECs are tracked through MIRECS.[8]

While 2021 was the last statutorily mandated compliance year, PA 235 was amended in 2023 requiring compliance again going forward with the Commission's approval of amended renewable energy plans (REPs). The Commission's February 8, 2024, Order in Case No. U-21568 set forth a staggered REP filing schedule requiring DTE Electric Company to file no later than July 19, 2024; Consumers Energy Company to file no later than November 15, 2024; Alpena Power Company, Indiana Michigan Power Company, Northern States Power Company, Upper Michigan Energy Resources Corporation, and Upper Peninsula Power Company to file no later than January 17, 2025; and co-operatives, municipally owned utilities, and alternative electric suppliers to file no later than February 27, 2025. At this time, DTE Electric Company filed an amended REP on July 19, 2024, in Case No. U-21662, while Consumers Energy Company filed on November 15, 2024, in Case No. U-21816. The statute gives the Commission 300 days, from the date of filing, to issue a final order on each of the REPs.

By the end of 2023, Michigan's rate-regulated electric providers had 5,882 MW of approved renewable energy projects within Michigan, as shown in the contract summary in **Appendix A**. It should be noted that the actual amount of renewable generation within the state will exceed this number as non-rate-regulated electric providers are not required to submit renewable energy contracts to the Commission for review. When factoring in rate-regulated electric provider projections in IRPs, it is expected that Michigan's rate-regulated electric providers will have 8,387 MW of operational renewable energy by the end of 2026, a 42.6% increase in just three years.

In addition to increasing the RPS, voluntary green purchasing (VGP) programs offered by the utilities continue to attract significant customer interest, more than doubling from fewer than 40,000 customers enrolled in 2020 to more than 100,000 participating today.

PA 235 also included several changes to the Distributed Generation (DG) program. Most notably, the program cap increased from 1% of a utility's average in-state peak load for the previous five years to 10% and also modified the internal categories that make up this overall percentage, creating more opportunities for residential and commercial project development. During 2023, the capacity of the generation participating in the DG program increased from 174,876 kW in 2022 to 189,879 MW in 2023, an 8.5% increase. Customer participation in these programs also continued to

[7] RECs used to comply in 2021 were primarily from renewable energy generated in 2019 and 2020.
[8] https://mirecs.org/

grow, increasing by 10.4% between 2022 and 2023, with 21,845 customers participating in DG programs at the end of 2023. In addition, these is also growing interest in pairing DG installations with battery storage, with 28.6 ME of distributed energy storage systems now installed by customers and interconnected with the utilities' distribution systems. Given the statutory increase in these DG programs, these trends are likely to continue moving forward.

Finally, like last year, this report also includes a high-level discussion of the Commission's ongoing efforts to implement the clean energy laws enacted at the end of 2023. This includes the clean energy standard, the establishment of a state-level siting process for certain wind, solar, and energy storage projects should they fail to win approval at the local level; and the work related to the statutory energy storage that utilities file plans to add 2500 MW of energy storage resources by 2030 and the Commission's ongoing study into long duration and multi-day energy storage opportunities.

Introduction

This report provides information on renewable energy activities involving the Michigan Public Service Commission (Commission or MPSC) through calendar year 2023 and summarizes data from electric provider 2023 annual reports and the contract summary as shown in **Appendix A**. Additionally, this report shows renewable energy projections through 2026 based on the renewable portfolio standard (RPS), voluntary green pricing programs (VGP), integrated resource plans (IRPs), public utility regulatory policies act (PURPA) resources, and the distributed generation and legacy net metering programs.[9]

Since the publication of this report last year, there have been significant legislative changes that will transform Michigan's electric generation portfolio in the coming years. Public Act 235 of 2023 (PA 235) requires electric providers to maintain a renewable portfolio requirement of 15% through 2029, 50% from 2030 through 2034, and finally achieve a 60% renewable portfolio in 2035 and each year thereafter. In addition, PA 235 increases the distributed generation program requirement for rate-regulated electric providers and alternative electric suppliers (AES) from 1% of average in-state peak load to 10%. Some rate-regulated electric providers had voluntarily increased their programs prior to this requirement, but none had reached 10% as is now legislatively required. PA 235 also established a clean energy standard for electric providers which will ultimately require 100% of the electric generation to come from resources that do not emit greenhouse gases or that capture and store carbon dioxide, along with a statewide energy storage target of 2,500 MW.

Finally, to help facilitate these new legislative requirements, Governor Whitmer signed Public Act 233 of 2023 (PA 233) into law which provides backstop siting authority to the Commission for utility scale wind, solar, and energy storage facilities.

While this report specifically focuses on renewable energy and distributed generation, the clean energy plan, storage requirements, and renewable energy and energy storage siting legislation will inevitably affect the future generation portfolio. Therefore, these requirements and the MPSC's related efforts are discussed in more detail in the subsequent section while the renewable energy portfolio requirements and distributed generation updates will be discussed throughout the report.

New Legislation

Clean Energy Plan

PA 235 established a clean energy standard of 80% by 2035 and 100% by 2040. The Commission will need to establish formats and guidelines for the clean energy plans by January 1, 2026. Electric providers will subsequently file these plans with the

[9] Subject to Section 51 of Public Act 295, as amended, the MPSC was directed to prepare an annual report summarizing the Commission's activities related to PA 295 and electric provider's annual reports. Section 51 was repealed effective January 1, 2023. The final reports issued pursuant to Section 51 are available at the MPSC's website: https://www.michigan.gov/mpsc/regulatory/reports/legislative

Commission – in IRPs for investor-owned utilities, by January 1, 2028, for cooperative electric utilities and alternative electric suppliers, and by July 1, 2028, for municipal electric utilities.

On February 8, 2024, the Commission issued an Order in Case No. U-21570 that directed Staff to provide a straw proposal related to providing formats and guidelines for investor-owned utilities, municipal electric utilities, cooperative electric utilities, and alternative electric suppliers to submit a clean energy plan pursuant to the requirements of PA 235. In accordance with the Order, Staff's redline version was posted to the Commission's website on September 30, 2024. Staff is also directed to hold public engagement sessions to discuss formats and guidelines related to the clean energy plan. Staff held the first of these outreach sessions on October 17, 2024. These efforts can be followed on the Commission's clean energy plan web page. [10]

Statewide Energy Storage Target

PA 235 establishes a statewide energy storage target of 2,500 MW. By Dec. 31, 2029, rate-regulated utilities will need to file petitions for approvals related to the storage target as part of their integrated resource plans pursuant to MCL 460.6t, and alternative electric suppliers (AES) will need to file plans for how they will comply with the target followed by complying with their plans in demonstrations required under Public Act 341 of 2016, Section 6w(8)(b). Rate-regulated utilities are required to begin filing annual storage reports no later than December 31, 2024.

On February 8, 2024, the Commission issued an Order in Case No. U-21571 that directed Staff to propose a methodology for calculating the proportional share of the statewide storage target for each rate-regulated utility and AES and to hold at least one public meeting, and it provided a comment period for all interested persons through August 1, 2024. As such, Staff posted its proposed methodology to the docket on May 29, 2024. Following that, Staff held a public meeting on June 12, 2024. In its initial February 8th Order in this case, the Commission stated that it "will endeavor to provide guidance in reaction to the straw proposal and any comments before the end of 2024."

PA 235 Section (7) also directed the Commission to complete a study on long-term energy storage systems and multiday energy storage systems within one year after the effective date of the amendatory act (by February 24, 2025). Staff is presently working with the United States Department of Energy (US DOE) to complete this study. In addition, Staff and Commissioners have joined the Long Duration Energy Storage National Consortium to, among other things, develop an informed understanding of the available technology and best practices nationwide. More

[10] https://www.michigan.gov/mpsc/commission/workgroups/2023-energy-legislation/clean-energy-standard

information is available on the Commission's Statewide Energy Storage Target web page.[11]

Renewable Energy and Energy Storage Siting

On November 28, 2023, Governor Gretchen Whitmer signed House Bill 5120 (PA 233 of 2023) which provides siting authority to the Commission for utility-scale wind, solar, and energy storage facilities under specified conditions.

On February 8, 2024, the Commission issued an Order[12] in Case No. U-21547 directing the Staff to hold public meetings starting in March 2024 to engage with experts, local units of government, project developers, and other interested persons. The objective of the engagement meetings was to consider issues relating to application filing instructions or guidelines, the potential use of consultants and assessment of application fees, pre-application consultations, guidance for use in the development of compatible renewable energy ordinances, and any additional issues that may arise during the engagement process. As directed by the initial February 8th Order in this case, Staff filed its proposed application instructions and procedures for renewable energy and energy facility siting[13] on June 21, 2024. Comments were filed by July 17, 2024, and reply comments by August 9, 2024. On October 10, 2024, the Commission issued an Order in Case No. U-21547 adopting application instructions and procedures. The MPSC created a renewable energy and energy storage web page to provide information about PA 233 implementation activities.[14]

Renewable Portfolio Standard

Public Act 295 of 2008 (PA 295) established Michigan's first renewable portfolio standard (RPS), requiring electric providers to meet an RPS of 10% by 2015, with interim targets beginning in 2012. Subsequently, Public Act 342 of 2016 (PA 342) increased the RPS to 12.5% in 2019 and 2020 and 15% in 2021, which was the final year of statutory RPS requirements until the amendments in PA 235. The RPS is applicable to Michigan's rate-regulated electric utilities, cooperative electric utilities, municipal electric utilities, and AESs. Electric providers filed initial REPs in 2009.[15] The 74 initial REPs described how each electric provider intended to meet the RPS requirements. Prior to PA 235 and PA 342, PA 295 directed electric providers to file REPs biennially for Commission review. PA 342 directed the Commission to review each electric provider's REP within one year of the PA 342 effective date and eliminated the requirement for biennial REP filings or compliance after 2021.

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[11] https://www.michigan.gov/mpsc/commission/workgroups/2023-energy-legislation/statewide-energy-storage-target
[12] https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000BubM7AAJ
[13] https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000E9g7hAAB
[14] https://www.michigan.gov/mpsc/commission/workgroups/2023-energy-legislation/renewable-energy-and-energy-storage-facility-siting
[15] Through the 2021 compliance year, there were 65 electric providers subject to the renewable energy standard, including 7 rate-regulated utilities, 10 cooperative utilities, 40 municipal utilities, and 8 AESs. 15 licensed AESs not currently serving customers are not included in this total.

PA 235 was signed into law in 2023. PA 235 requires electric providers to meet and maintain a renewable portfolio requirement of 15% through 2029 that increases to 50% from 2030 through 2034, and finally achieves a 60% renewable[16] portfolio in 2035 and each year thereafter. In addition, PA 235 reinstated the requirement for biennial REP plan filings and a new 20-year planning period ending in 2045.

All seven of Michigan's rate-regulated electric providers continued to maintain a 15% renewable energy credit[17] (REC) portfolio from 2021 through the end of the 20-year plan period in 2029 under PA 342 REPs. In addition to the portfolio standard, many of Michigan's providers had planned for additional renewable generation growth as part of their IRPs prior to PA 235 in 2023.

To date, only DTE Electric Company and Consumers Energy Company have filed amended REPs under PA 235. DTE Electric Company filed on July 19, 2024, in Case No. U-21662,[18] while Consumers Energy Company filed on November 15, 2024 in Case No. U-21816[19]. The Commission's February 8, 2024, Order in Case No. U-21568 sets forth a staggered REP filing schedule with Alpena Power Company, Indiana Michigan Power Company, Northern States Power Company, Upper Michigan Energy Resources Corporation, and Upper Peninsula Power Company filing no later than January 17, 2025; and cooperatives, municipally owned utilities, and alternative electric suppliers filing no later than February 27, 2025. PA 235 Section 28(5) requires that electric providers meet the portfolio requirements by generating renewable electricity, purchasing the renewable energy and capacity, or purchasing renewable credits within the regional transmission organization, but the provider is limited to 5% of its total renewable portfolio from this last option, subject to certain exceptions. Combined with the locational requirements contained within PA 235 Section 29(1), the amended RPS will result in a significant amount of new renewable energy resources within Michigan in the coming years.

Per PA 235 Section 49(1), seven rate-regulated electric providers filed annual renewable energy cost reconciliation cases for 2022. Commission staff examined the pertinent revenues and expenses, determined the electric provider's compliance with its filed REP, and assessed whether the provider met its compliance targets.[20]

Electric providers were directed by Section 51(1) of PA 295 to file annual reports for each plan year beginning with 2009. While this section is repealed, the Commission

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[16] https://mi-psc.my.site.com/s/case/500cs00000FaAmdAAF/in-the-matter-of-consumers-energy-companys-application-for-the-regulatory-reviews-revisions-determinations-andor-approvals-necessary-to-fully-comply-with-public-act-295-of-2008-as-amended-by-public-act-235-of-2023

[17] The term "renewable energy credit" includes renewable energy credits, Michigan incentive renewable energy credits, and energy waste reduction credits when substituted for renewable energy credits.

[18] https://mi-psc.my.site.com/s/case/5008y00000B4iG7AAJ/in-the-matter-of-dte-electric-companys-application-for-the-regulatory-reviews-revisions-determinations-andor-approvals-necessary-to-fully-comply-with-public-act-295-of-2008-as-amended

[19] https://mi-psc.my.site.com/s/case/500cs00000FaAmdAAF/in-the-matter-of-consumers-energy-companys-application-for-the-regulatory-reviews-revisions-determinations-andor-approvals-necessary-to-fully-comply-with-public-act-295-of-2008-as-amended-by-public-act-235-of-2023

[20] Link to electric provider reconciliation filings: https://www.michigan.gov/mpsc/0,9535,7-395-93308_93325_93423_93502_94989-506587--,00.html

issued several Orders in Case No. U-15825 *et al* on July 27, 2022, requesting that non-rate-regulated electric providers continue to submit annual reports voluntarily through the end of the 20-year plan period in 2029. Rate-regulated electric providers will continue to provide annual reports as part of their renewable energy cost reconciliation cases. Michigan electric provider annual reports for 2009 through 2021 are available on the Commission's website.[21]

Voluntary Green Pricing Programs

Section 61 of PA 342 requires each electric provider to "offer its customers the opportunity to participate in a voluntary green pricing program." These programs provide customers the option to match up to 100% of their electric usage sourced from renewable energy, and, in recent years, VGP programs have become a major driver of new renewable energy growth in Michigan. Electric providers whose rates are regulated by the Commission have developed these programs and the Commission has approved the rates paid by participating customers for renewable energy. After the initial utility VGP case filings were conducted in 2017 and 2018, the Commission established a biennial review timeframe for these cases.

Although VGP is intended to provide additionality outside of the RPS and is funded through subscribing participants, both Consumers Energy and DTE Electric have requested and received Commission approval to utilize the PA 295 renewable energy cost recovery mechanism for any unsubscribed portion of the VGP program renewable energy supply. This cost recovery mechanism has several advantages over traditional utility cost recovery for these programs, including:

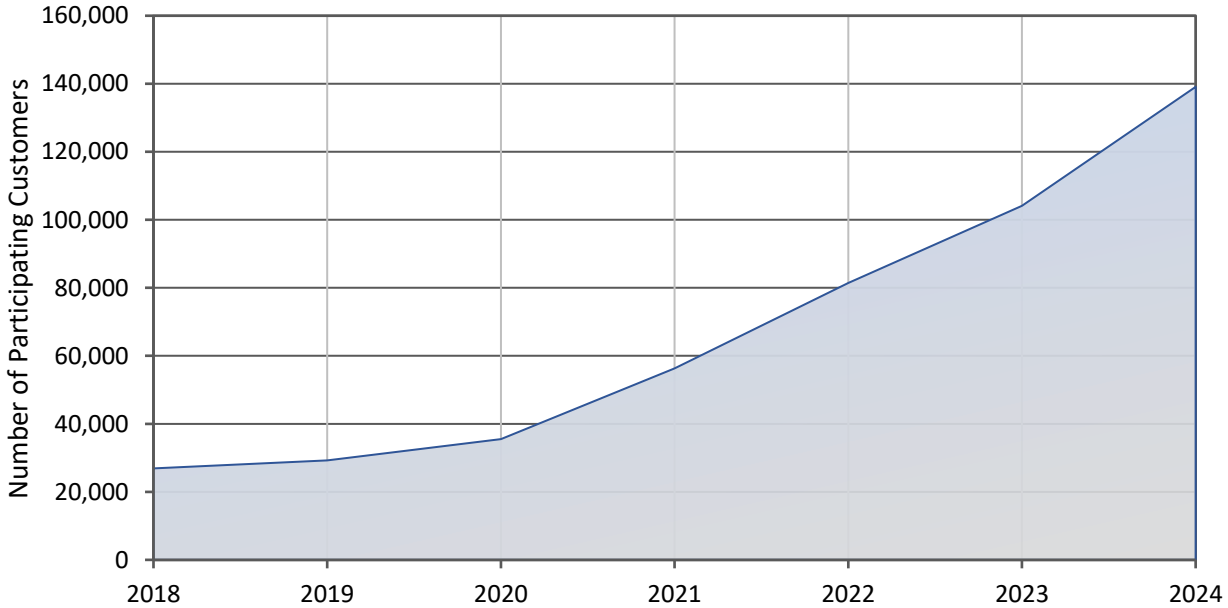
- Under the renewable energy plan cost recovery mechanism, utility cost recovery begins when the project achieves commercial operation.
- The cost recovery mechanism allows the utility to recover costs according to traditional utility revenue requirement and depreciation accounting methods while the participating customer pays for renewable energy on a levelized cost basis for the life of the project. Under a traditional generation asset cost recovery methodology, the utility revenue requirement is higher than the project's levelized cost in the first half of the project life and lower in the last half.

With the amendments to PA 342 in PA 235, VGP participation can now offset the proportional load when calculating the electric providers' RPS requirement. Any RECs associated with a customer's participation in a VGP program may not be used for the electric provider's RPS compliance, because, as previously mentioned, the program is intended to promote additionality.

[21] Link to 2023 electric provider annual reports: https://www.michigan.gov/mpsc/regulatory/electricity/renewable-energy/renewable-energy-filings/2023-renewable-energy-annual-reports

VGP programs in Michigan continue to experience strong growth, particularly from commercial and industrial customers. The demand for VGP program supply is significantly contributing to renewable energy growth, as evidenced in **Figure 1**.[22]

Figure 1: Total VGP Customer Participation*



*Customer participation data are available through October 2024

Utility Integrated Resource Plans

As shown in **Figure 5,** renewable energy costs in Michigan have declined since the first PA 295 renewable energy supply contracts in 2009 and are competitive when compared to non-renewable resources. These economic factors and environmental benefits related to renewable generation are key contributors to the selection of renewable energy projects as a supply resource in capacity planning efforts outside of the RPS.

Public Act 341 of 2016 (PA 341), Section 6t, requires utilities to file IRPs every five years that look at anticipated customer electricity needs over the next 5, 10, and 15 years (although many plan out to 20 years and beyond), as well as the appropriate mix of resources to serve those needs, including base load generation, renewable energy, energy waste reduction, demand response, energy storage, and customer-owned resources. The first rounds of IRPs have concluded with updates coming in 2025 and 2026. Renewable energy, particularly solar, continues to be a key resource in the future supply mix to meet customer electricity needs.

Table 1 summarizes the most recent IRPs and planned renewable energy additions included in utilities' preferred course of action.

[22] This graph shows data from the most recently filed annual VGP filings.

Table 1: Integrated Resource Plans – Preferred Course of Action Renewable Energy Additions

Utility	MPSC Case Number	Renewable Energy Approved for the Initial 3-Years	Renewable Energy in Current Preferred Course of Action throughout IRP Planning Horizon
Alpena Power	U-20300	None	Provided through future REC contracts*
Consumers Energy	U-21090	250 MW solar	4,500 MW of solar by 2030 and 6,000 MW by 2040
DTE Electric	U-21193	400 MW solar	6,500 MW solar and 8,900 MW wind
Indiana Michigan**	U-21189	800 MW wind, 500 MW solar	2,200 MW solar and 1,600 MW wind
Northern States Power Wisconsin Xcel**	U-20599	None	5,200 MW (4,000 MW solar, 1,200 MW wind)
Upper Michigan Energy Resource Corporation	U-21081	None	100 MW solar
Upper Peninsula Power Company	U-20350	20 MW solar	62.5 MW PPA and 62.5 MW of company-owned solar

*Explained in Renewable Energy Reconciliation Case No. U-21351[23]
**Data provided for Indiana Michigan Power Company and Northern States Power Wisconsin (Xcel) is representative of the Companies' multi-state service territories.

Renewable energy quantities are subject to change according to actual contracting results and adjustments to the preferred course of action in future IRP cases.

PURPA Purchases

In 1978, Congress passed the Public Utility Regulatory Policies Act, commonly referred to as PURPA. PURPA requires that electric utilities interconnect with qualifying facilities (QF), purchase energy and capacity at the utility's avoided cost, and sell supplemental, backup, maintenance, and interruptible power to the QF on a non-discriminatory basis. Michigan has seen considerable growth in the number of QFs that have projects, or are planning projects, with investor-owned utilities.

During 2019 and 2020, Consumers Energy had a significant increase in the number of executed PURPA QF Power Purchase Agreements (PPAs) resulting in the vast majority of new PURPA resources within the state. The surge was the result of a settlement agreement approved in the September 11, 2019 Order in Case No. U-20615.[24] In this Order, Consumers Energy agreed to award 170 MW to PURPA QFs of 20 MW or smaller that were in its interconnection queue as of a chosen cutoff date.

[23] https://mi-psc.my.site.com/s/case/5008y000006erhDAAQ/in-the-matter-of-the-application-of-alpena-power-company-to-commence-a-renewable-energy-cost-reconciliation-proceeding-for-the-12month-period-ended-december-31-2022
[24] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000005XvMxAAK

Consumers Energy also agreed to award 414 additional MW to PURPA QFs of 20 MW or smaller that were in Consumer Energy's interconnection queue as of a second chosen cutoff date. **Appendix B** includes project sizes and locations for PURPA projects under Michigan Utility Scale Solar Farms.

In 2020, the Federal Energy Regulatory Commission (FERC) issued Order No. 872, reducing the rebuttable presumption for nondiscriminatory access to power markets from 20 MW down to five MWs for small power production facilities, which includes solar and wind.[25] Since this time, FERC has allowed Consumers Energy, DTE, Indiana Michigan Power Company, Northern States Power Company, Upper Peninsula Power Company, and Upper Michigan Energy Resources Corporation to terminate the requirement under section 292.303(a) of PURPA to enter into new contracts or obligations to purchase electric energy and capacity from any small power production qualifying facility (QF) with a net capacity greater than five megawatts. This has resulted in a significant slowdown of PURPA related contracts being filed with the Commission for approval.

Renewable Energy Data

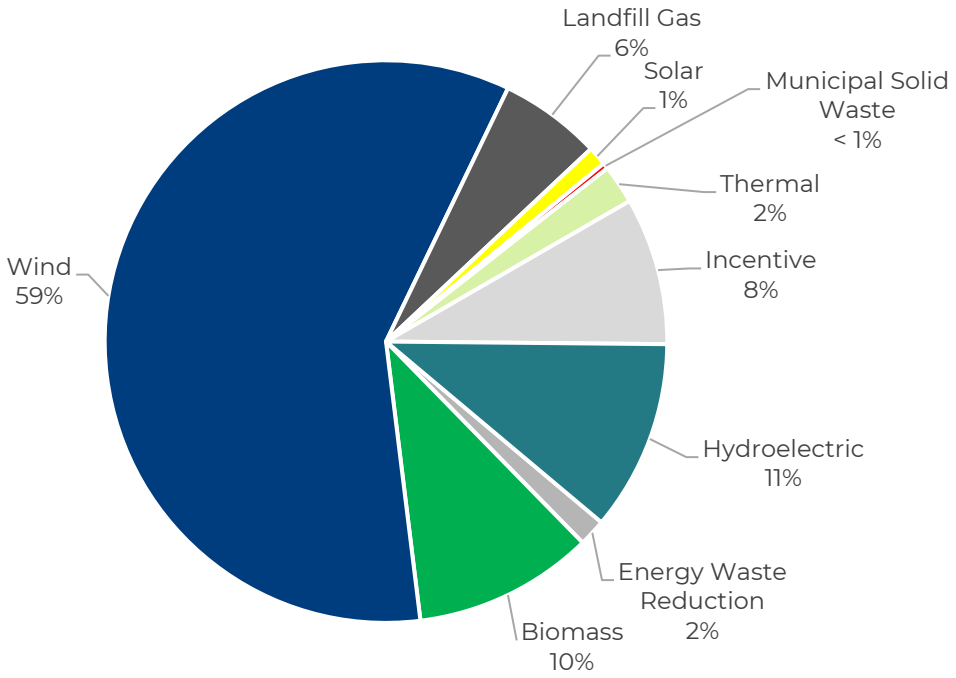
2021 Compliance

PA 342 required providers to meet the 15% renewable portfolio standard through 2021. Section 28 of the Act was rescinded therefore eliminating the statutory requirement. After 2021, all rate-regulated electric providers planned to maintain a 15% standard. Additionally, most of the non-rate-regulated electric providers had intended to continue to meet the 15% standard voluntarily prior to the requirements set forth in PA 235. The number of RECs required for 2021 compliance was calculated by multiplying the applicable electric provider retail sales figure by the 15% compliance percentage. All of Michigan's electric providers subject to the standard in 2021 met the standard and retired[26] a total of 14,545,315 RECs. **Figure 2** shows the different renewable energy technologies used to generate RECs for the 2021 compliance by all electric providers compared to 2023. The compliance chart in **Figure 2** shows wind as the primary sources of RECs used for compliance due to electric providers using a first in–first out methodology from their REC bank as RECs have a five-year life. The Compliance RECs chart show what was retired to meet the 2021 requirement, while the Portfolio RECs chart shows what was voluntarily retired in 2023 as the statute no longer required compliance after 2021.

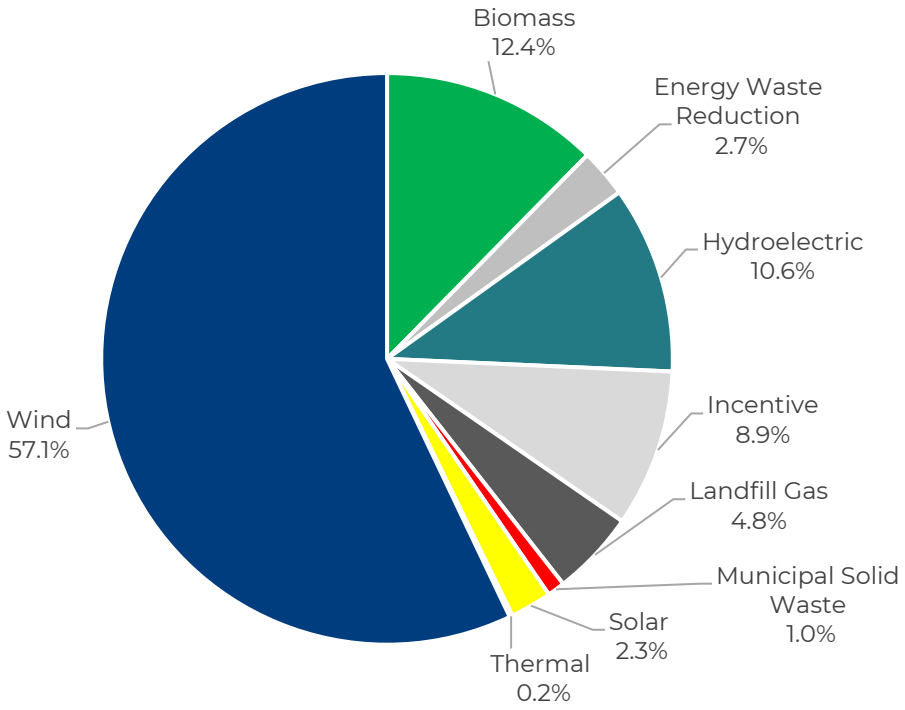
[25] https://www.ferc.gov/sites/default/files/2020-07/07-2020-E-1.pdf
[26] RECs are "retired" when used for compliance.

Figure 2: Compliance REC Breakdown

All Electric Providers – 2021 Compliance RECs
14,545,315 Total RECs



All Electric Providers- 2023 Portfolio RECs
14,591,614 Total RECs



Section 29 of PA 342 includes provisions for determining whether the location of a renewable energy project is eligible for Michigan's renewable portfolio standard. Nearly 97% of the RECs used for 2021 compliance were from renewable energy generated in Michigan. Indiana was the source of 1.5%, Wisconsin was 1.4%, and a small number of RECs came from renewable energy generated in Iowa and Minnesota.

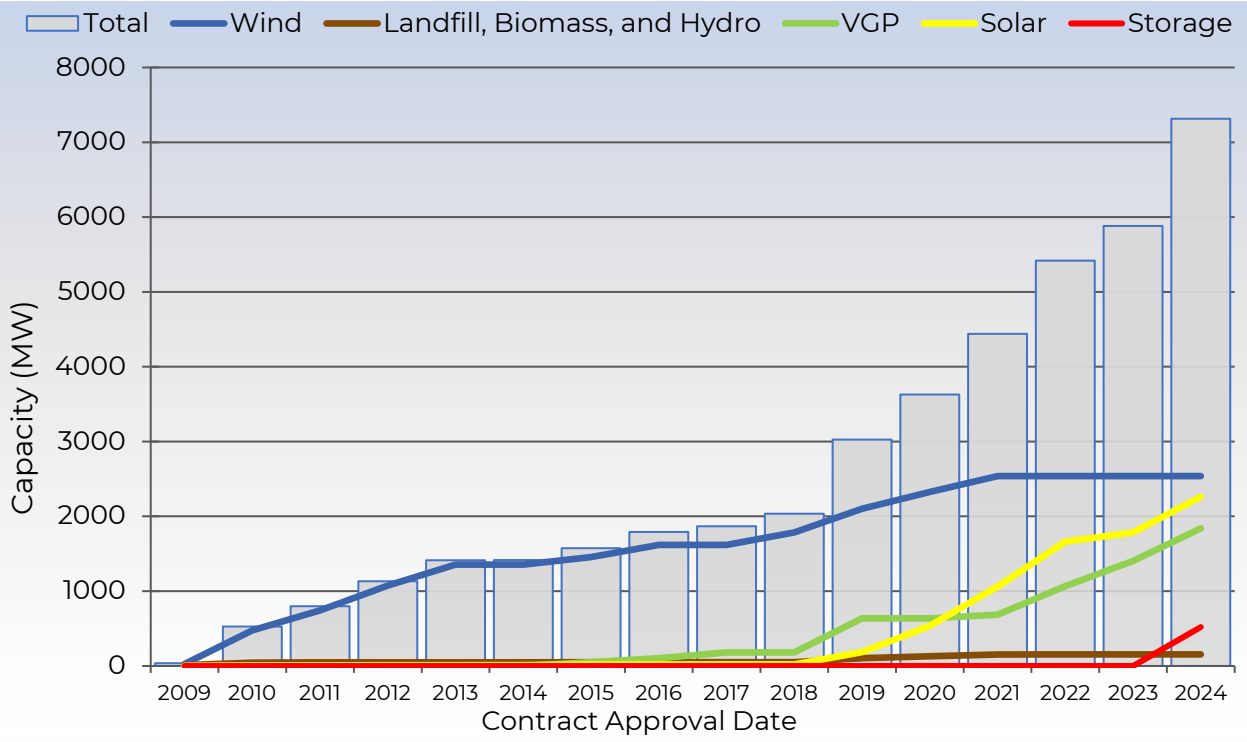
2023 Voluntary Compliance

A total of 14,591,614 RECs were voluntarily retired in 2023 with banked RECs and incentive RECs (and in the case of Consumers Energy and DTE Electric, substituting a limited quantity of energy waste reduction credits for RECs). These REC retirements were calculated by multiplying the applicable electric provider retail sales figure by the 15% compliance percentage. Over 98% of the RECs used for the 2023 voluntary retirement portfolio were from renewable energy generated in Michigan. Wisconsin was the source of 1.2%, and a small number of RECs came from Iowa, Minnesota, and Indiana.

Figure 3 shows the growth of renewable capacity based on contracts filed for approval with the Commission as shown in **Appendix A.** Renewable projects developed by non-rate-regulated electric providers, where contracts are not filed for approval with the MPSC, are not reflected in **Figure 3**.[27]

[27] Nearly all AESs are purchasing unbundled renewable energy credits to meet the renewable energy credit portfolio requirements. The terms and conditions of these purchases are unknown.

Figure 3: Cumulative Commission-Approved Renewable Energy Portfolio Capacity

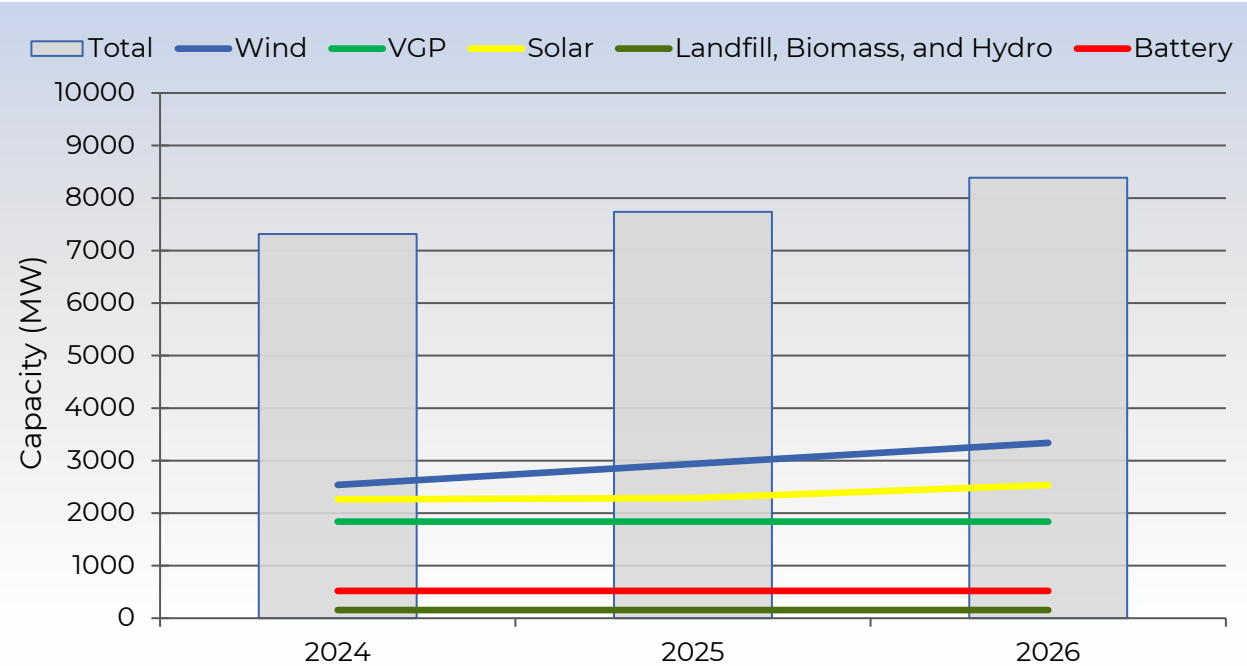


Based on data available through August 2024

Figure 4 shows anticipated capacity additions based on IRP projections (including IRP modeled PURPA) as currently approved by the Commission. It is expected that Michigan will have over 8,000 MW of renewable energy capacity operating by the end of 2026.[28] While the planning period for IRPs is 20 years, the figure shows the three-year pre-approved capacity additions from the most recently filed IRPs.

[28] This number is based on projects that have been approved or will be reviewed by the Commission. This does not include projects from electric providers that are not subject to rate-regulation or renewable generation that existed prior to PA 295.

Figure 4: Commission-Approved Projected Cumulative Renewable Energy Capacity



Renewable Energy Cost

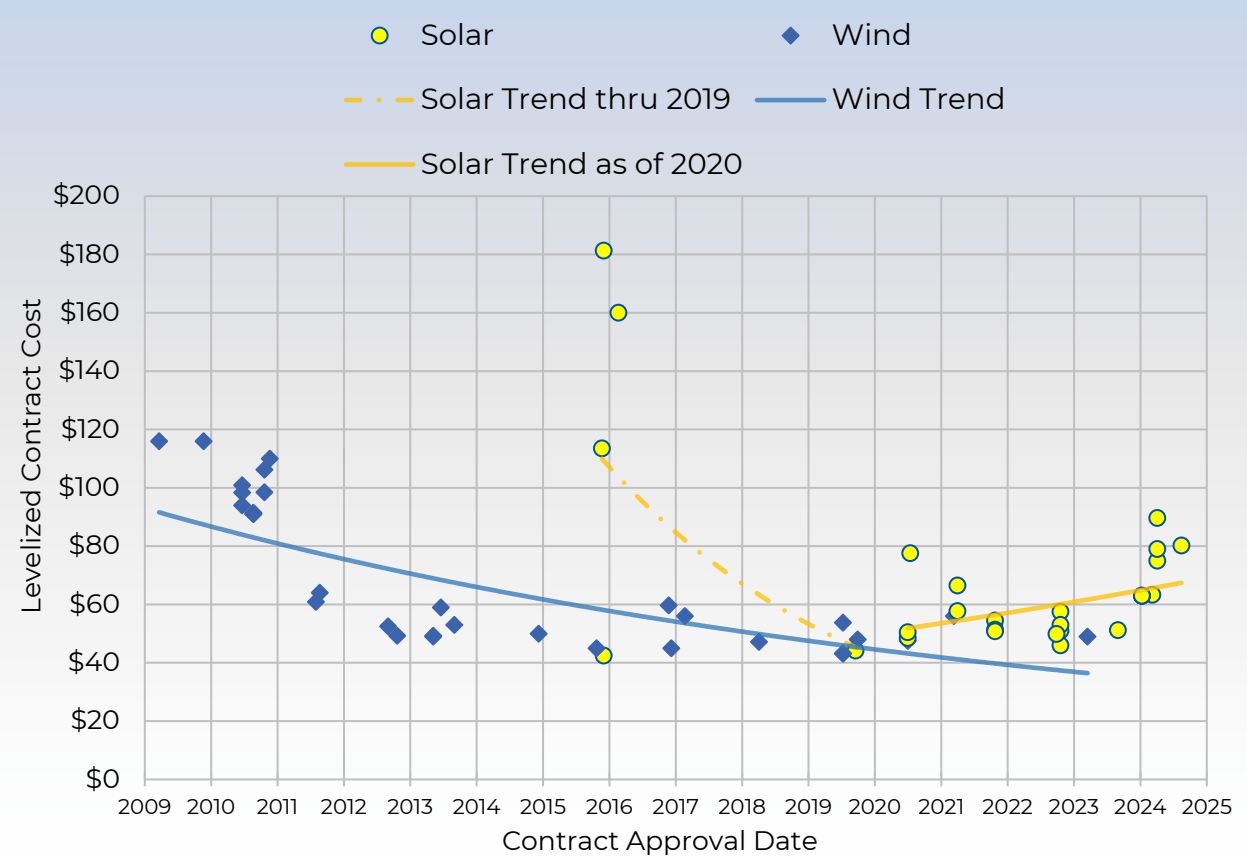
While wind generation was the prominent new renewable energy resource to meet the RPS for many years after the passage of PA 295 in 2008, the rapid decrease in solar costs and continuing siting concerns for wind contributed to a transition toward solar starting around the mid-2010s. Solar has become one of the fastest growing resources, not only in Michigan, but throughout the country.

However, challenges relating to the Midcontinent Independent System Operator (MISO) queue process, difficulties in obtaining local siting approval, and disruptions within the solar supply chain have resulted in slower-than-expected project development.

Michigan electric providers have cited these issues as factors forcing both the extension of commercial operation dates and pricing increases for solar resources in Michigan, which are further compounded by overall inflation. The renewable energy contracts submitted to the Commission since PA 295 took effect in 2008 had historically shown significant cost reductions, but the effects of these economic events began appearing as an upward solar pricing trend in approved contracts after 2019. In addition, due to commercial operation date delays and pricing updates, several contracts submitted to the Commission have required pricing amendments, timeline extensions, or have been terminated altogether. It is hoped that PA 233 will help to mitigate some of the siting issues going forward as Michigan transitions its

generation fleet toward a more carbon free future. However, as shown in **Figure 5**[29], these issues have resulted in solar pricing increases beginning in the early 2020s.

Figure 5: Renewable Energy Pricing Trends



Based on data available through August 2024

Pursuant to the former PA 295 Section 37, amended by PA 235 Section 28, renewable energy power purchase and REC-only agreements entered into by any electric provider whose rates are regulated by the Commission must be submitted to the Commission for approval. **Appendix A** has been expanded to include PURPA, VGP, and utility IRP contracts in addition to PA 295 renewable energy REP contracts approved by the MPSC.

Commission staff continues to review competitive bidding activities through process audits for all contracts submitted to the Commission for approval. The purpose and design of the audits are to ensure that the utilities followed the processes and procedures previously outlined in the Commission's December 4, 2008, Temporary Order in MPSC Case No. U-15800, Attachment D[30] and pursuant to the former

[29] These levelized costs do not include PURPA contracts as those are mostly based on variable MISO market rates.
[30] https://mi-psc.force.com/s/filing/a00t0000005pa5hAAA/u158000001

Section 33 of PA 295. On August 20, 2020, the Commission opened a docket in Case No. U-20852 and directed Staff to convene a competitive bidding collaborative, referred to as the Competitive Procurement Workgroup. Rate-regulated utilities and other interested parties participated in the Competitive Procurement Workgroup to develop recommended competitive bidding guidance that aligns with the comprehensive planning processes being developed through the MI Power Grid collaborative.[31] The Commission's objective for the Competitive Procurement Workgroup was to ensure strong, technology-neutral market response and value for ratepayers through transparency, non-discriminatory access, certainty, and fairness in bidding processes. On September 9, 2021, the Commission adopted new Competitive Procurement Guidelines for rate-regulated electric utilities in Case No. U-20852.[32] These new guidelines have been implemented for all contracts approved by the Commission since their adoption. In keeping with the spirit of the Temporary Order in U-15800, the new guidelines continue the Staff audit process.

Distributed Generation and Legacy Net Metering

The Distributed Generation (DG) and Legacy Net Metering programs (collectively DG program) enable Michigan's electric provider and AES customers to install on-site renewable energy electric generation projects to meet some or all of their electric energy needs and reduce their electric bills.

In additional to increasing the RPS, PA 235 included several key changes to the DG program. These changes include the following:

1. Section 173(2) increases the eligible participant generation capacity from 100% of the customer's electricity consumption for the previous 12 months to 110%.
2. Section 173(3) increases the program cap from 1% of a utility's average in-state peak load for the previous five years to 10%. Additionally, the 10% limit under this subsection is to be allocated as follows: (a) Not less than 50% for customers with an eligible electric generator capable of generating 20 kilowatts or less; (b) Not more than 50% for customers with an eligible electric generator capable of generating more than 20 kilowatts but not more than 550 kilowatts.
3. Section 173 removes the generation meter requirement for DG projects.
4. Section 177(2) allows the outflow credit to offset the total bill rather than being limited to only power supply charges.[33]

Project size is limited to 550 kW such that the annual generation does not exceed 110% of the customer's annual electricity consumption. Customers reduce electricity

[31] https://www.michigan.gov/mpsc/commission/workgroups/mi-power-grid/competitive-procurement
[32] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000TTDJAAA5
[33] https://www.legislature.mi.gov/documents/2023-2024/publicact/pdf/2023-PA-0235.pdf

purchases from the utility by using their generated electricity "behind the meter" and receive a credit for excess generation.

DG program for projects 20 kW and smaller (certified equipment)

The 20 kW and under DG program is available to any customer meeting the generator size requirements and using an Underwriters Laboratory (UL) 1741 certified inverter. Typically, residential customers would fit within this size level.

Program features:

- Billing based on an inflow and outflow mechanism for customers of utilities with the new DG tariff in place.[34] Inflow represents kWh delivered by the utility and is billed at the full retail rate. Outflow represents kWh generated by the customer but not used on-site. To date, the outflow credit has been equal to the power supply component of the full retail rate and may have transmission costs subtracted.
- A generator meter is available at cost, if requested by the customer. (The generator meter allows the customer to monitor the amount of generation. Utilities are not obligated to read a customer's generator meter.)
- A maximum program and interconnection application processing fee of $50. Customers pay all interconnection costs.
- Not less than 50% of a utility's program capacity of 10% based on peak load for the previous 5 years is for customers with an eligible electric generator capable of generating 20 kilowatts or less.

DG program for projects over 20 kW and as large as 550 kW

This DG program for larger generators is available to any customer meeting the generator size requirements. Typically, these customers would be commercial, small industrial, or institutional customers.

Program features:

- Billing based on an inflow and outflow mechanism. Inflow represents kWh delivered by the utility and is billed at the full retail rate. Outflow represents kWh generated by the customer but not used on-site. To date, the outflow credit has been equal to the power supply component of the full retail rate and may have transmission costs subtracted.
- A maximum program and interconnection application processing fee of $50. Customers pay all interconnection costs.

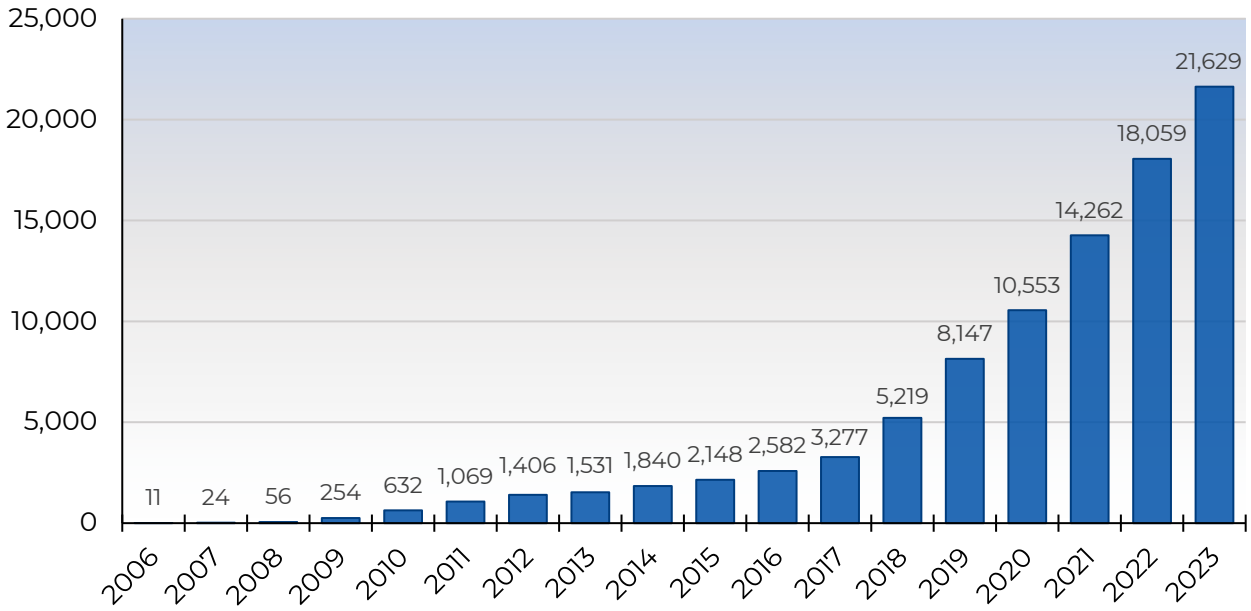
[34] For the legacy net metering program, the billing is based on net usage with the credit for excess generation equal to the full retail rate.

- Not more than 50% of a utility's program capacity of 10% based on peak load for the previous 5 years is for customers with an eligible electric generator capable of generating more than 20 kilowatts but not more than 550 kilowatts.

Distributed Generation Program Data

Customer participation in the DG program increased from 18,0591 customers at the end of 2022 to 21,629 through 2023, a 10.4% annual increase. Similarly, installations grew from 19,778 installations in 2022 to 21,845 installations in 2023. A complete list of projects by electric provider, ZIP code, type and size is available on the Commission's website.[35] As of the release of this report, the total capacity of DG program installations was approximately 189,680 kW, an increase of 14,804 kW, or 8.5%, from the 174,876 kW capacity installed at the end the previous year.[36] As shown in **Figure 6**, program participation continues to increase each year.

Figure 6: Total Distributed Generation Program Customers



Source: 2023 Electric Provider Annual Program Reports, Cases No. U-15787[37] and U-20890[38] and updated Staff surveys.

[35] https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/regulatory/electric/ren-energy/2023-DG-Program-Data.xlsx
[36] https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/regulatory/reports/RE-DG/2023-Renewable_Energy_Distributed_Generation_Legacy_Net_Metering_Report.pdf
[37] https://mi-psc.force.com/s/case/500t0000008efMtAAI/in-the-matter-on-the-commissions-own-motion-to-promulgate-rules-governing-interconnection-and-net-metering
[38] https://mi-psc.my.site.com/s/case/500t000000qsg3uAAA/in-the-matter-on-the-commissions-own-motion-to-promulgate-rules-governing-electric-interconnection-and-distributed-generation-and-to-rescind-legacy-interconnection-and-net-metering-rules

PA 235 allows utilities to cap participation of DG programs at 10% of average annual peak load, with not less than 5% for customers with an eligible electric generator capable of generating 20 kilowatts or less and not more than 5% for customers with an eligible electric generator capable of generating more than 20 kilowatts but not more than 550 kilowatts. In Case No. U-18383, the Commission ordered the implementation of inflow/outflow tariffs for utilities in any rate case filed after June 1, 2018. UMERC, the final utility to file its first rate since that order, received approval for its DG program as part of a settlement agreement approved by the Commission on October 10, 2024. A summary of activities related to the DG tariff expansion is provided in **Table 2**.

Table 2: Summary of Distributed Generation Program Tariff Implementation

Utility	Beginning DG Program Enrollment Date	Case Number approving DG program Cap
Alpena Power	January 1, 2022	U-21045
Consumers Energy	January 1, 2021	U-21124
DTE Electric	May 9, 2019	U-21193
Indiana Michigan	February 1, 2020	U-20359
NSP	January 1, 2023	U-21097
UMERC	January 1, 2025	U-21541
UPPCO	May 24, 2019	U-20995

Table 3: Distributed Generation Program Data

Company	20 kW and Less Nameplate Capacity (kW)	>20 kW to 550 kW Nameplate Capacity (kW)
Rate-Regulated Utilities (Act 235 Statewide DG Program)		
Alpena	**151**	
Consumers Energy	**70,994**	**29,194**
DTE Electric	**60,130**	**11,165**
Indiana Michigan	**4,498**	**1,201**
UMERC	**580**	**142**
UPPCO	**2,340**	**61**
Xcel	**57**	
Sub Total	**138,750**	**41,763**
Member-Regulated Cooperative Utilities with Programs for Small Scale Distributed Generation		
Alger Delta	**155**	**90**
Cherryland	**94**	
Cloverland	**270**	**417**
Great Lakes Energy	**3,575**	**525**
Homeworks Tri-County	**1,483**	**93**
Midwest	**1,792**	
Ontonagon	**206**	
Presque Isle	**143**	
Thumb	**290**	**40**
Sub Total	**8,008**	**1,165**
Total	**146,758**	**42,928**

All rate-regulated utility data through 2023. All other data is through 2022.

Member-regulated cooperatives are not required to offer the statewide DG program. Data provided reflects voluntary programs. Alger Delta, Cherryland, Ontonagon, Presque Isle, and Thumb data is from previous reporting years.

Alternative electric supplier program data is included in utility reporting.

Source: 2023 Electric Provider Annual Program Reports, Cases No. U-15787[39] and U-20890,[40] and updated Staff surveys

[39] https://mi-psc.force.com/s/case/500t0000008efMtAAI/in-the-matter-on-the-commissions-own-motion-to-promulgate-rules-governing-interconnection-and-net-metering
[40] https://mi-psc.my.site.com/s/case/500t000000qsg3uAAA/in-the-matter-on-the-commissions-own-motion-to-promulgate-rules-governing-electric-interconnection-and-distributed-generation-and-to-rescind-legacy-interconnection-and-net-metering-rules

Table 4: Distributed Generation Cap Space Remaining

Company	20 kW and Less Allocated Amount (kW)	Current 20 kW and Less Capacity (kW)	20 kW and Less Remaining Space (kW)	>20 kW to 550 kW Allocated Amount (kW)	Current >20 kW to 550 kW Capacity (kW)	>20 kW to 550 kW Remaining Space (kW)
Rate-Regulated Utilities (Act 235 Statewide DG Program)						
Alpena	**3,170**	**151**	**95%**	**3170**	**0**	**100%**
Consumers	**375,680**	**70,994**	**81%**	**375,680**	**29,194**	**92.2%**
DTE Electric	**435,704**	**60,130**	**86%**	**435,704**	**11,165**	**97.4%**
I&M	**32,440**	**4,498**	**86%**	**32,440**	**1,201**	**96.3%**
UMERC	**14,610**	**580**	**96%**	**14,610**	**142**	**99%**
UPPCO	**7,290**	**2,340**	**68%**	**7,290**	**61**	**99.2%**
Xcel	**1,263**	**57**	**96%**	**1,263**	**0**	**100%**

Table 3 summarizes DG program capacity and category cap by electric provider for all program sizes. Pursuant to PA 235, DG programs are allocated into two size categories. Projects up to 20 kW are available to new customers until the program size reaches at least 5% of the electric provider's average in-state peak load for the preceding five calendar years or the voluntarily increased program size offered by the electric provider. DG projects greater than 20 kW and 550kW are available to new customers until the program size reaches up to 5% of the electric provider's average in-state peak load for the preceding five calendar years or the voluntarily increased program size offered by the electric provider. **Table 4** shows the remaining capacity in both DG categories for each regulated utility updated to the 10% cap established in PA235. To date the only AESs with customers participating in the DG program are Constellation New Energy and Direct Energy, with a combined total of 23 customers. AES DG program customers are included in utility reporting and are not shown separately on **Table 3**.

Michigan's cooperative electric providers are not required to offer the statewide DG program pursuant to statute. However, many of these electric providers have established programs for customer distributed generation and voluntarily provide annual reporting data to the MPSC Staff for inclusion in this report.

With the change from the legacy net metering program, which credited excess generation at the full retail rate, to the DG program, which credits outflow generation at a rate less than the full retail rate, it is becoming increasingly advantageous for customers to utilize as much of the energy they produce on-site as possible. Given the reduced outflow credit value and the declining costs of battery storage, participants are increasingly interested in pairing their generation with battery storage. The scope of the annual reporting form was expanded in 2021 to gather data about whether customers were participating in the legacy net metering or DG programs and to collect customer battery storage information. Through 2023,

electric providers reported 3,879 DG program customers with battery storage for a total battery storage capacity of 28,560 kW. A summary of battery storage capacity by utility is provided in **Table 5**.

Table 5: Michigan Distributed Generation Program Customers with Battery Storage

Company	No. of Customers	Battery Storage Capacity (kW)
Consumers Energy	**1,394**	**14,036**
DTE Electric	**2,383**	**13,882**
Indiana Michigan	**102**	**642**
Total	**3,879**	**28,560**

The Commission continues to see significant interest in the DG program in contested cases. Staff and the Commission will continue to participate actively in efforts to craft the future of DG programs in Michigan.

Conclusion

The Commission is pleased to note that all electric providers were able to achieve the renewable portfolio standard for 2021, and work is underway to implement the updated renewable energy standards established under PA 235. To date, Consumers Energy and DTE have filed their REPs, with the other electric providers set to file their plans early in 2025. The combined efforts of the electric providers, renewable energy project developers, landowners and communities hosting renewable energy projects, renewable energy advocates, and many others have contributed to the effective implementation of Michigan's RPS. The RPS can be credited with the development and planned development of over 6,000 MW of new renewable energy projects through 2023 and has paved the way for utilities to continue developing and contracting for renewable energy well into the future.

There has been extensive renewable energy and DG growth as a result of PA 295. This law was the keystone for providers to gain experience with these resources and allowed for the continued development of renewable energy and DG in Michigan electric providers' forward planning processes and PA 235 requirements.

DG programs have allowed Michigan customers a means to offset a portion of their electric bills and helped to reduce electric providers' need to provide energy resources during the times that customers' DG resources are generating. We continue to see significant interest and growth in these programs and will continue to monitor utility program sizes with the ten-fold increase in authorized participation in utility DG programs under PA 235.

The Commission looks forward to working with electric providers, interested parties, and the public as we continue to implement the new legislative requirements.

Appendices

Utility	Seller (Link goes to application requesting contract approval and includes the contract.)	County	Quantity MW	Contract Type	Price	Price Description	Term	Renewable Energy Type	Request for Proposal	Commission Approval (Date links to Order)	Amendment 1	Amendment 2	Current Commercial Operation Date	Previous Commercial Operation Date
UMERC	Renegade Solar Energy, LLC	Delta	100	PSA	$89.67/MWh	LCOE	Company Owned	Solar	No formal RFP	4/11/2024			12/31/2026	
DTE	Coldwater River Solar, LLC	Branch	150	PPA	$75/MWh	LCOE	30	Solar	3/17/2023	4/11/2024			3/31/2026	
DTE	White Pine Grove Solar, LLC	Calhoun	100	PPA	$79/MWh	LCOE	25	Solar	3/17/2023	4/11/2024			3/31/2026	
Consumers	Tibbits Energy Storage, LLC	Branch	100	PPA	$200,085/ZRC	LCOC	20	Storage	9/29/2022	4/11/2024			5/31/2025	
DTE	Trenton Channel Energy Center	Wayne	220	PCA	TBD	LCOC	Company Owned	Battery	2/13/2023	3/15/2024			TBD 2025	
Consumers	Freshwater Solar, LLC	Montcalm	300	PPA	$63.29/MWh	LCOE	20	Solar	12/8/2022	3/15/2024			6/1/2027	
DTE	Fish Creek Solar	Montcalm	132	VGP	$63/MWh	LCOE	Company Owned	Solar	3/17/2023	1/18/2024			9/30/2025	
DTE	Little Trout Solar	Presque Isle	150	VGP	$63/MWh	LCOE	Company Owned	Solar	3/17/2023	1/18/2024			12/31/2025	
DTE	Mission Road Co-Location Solar	Isabella	153	VGP	$63/MWh	LCOE	Company Owned	Solar	3/17/2023	1/18/2024			12/31/2025	
Consumers	Sunfish Solar 2 Project	Calhoun	309	VGP	$51.21/MWh	LCOE	BTA	Solar	3/17/2022	9/28/2023				
I&M	Elkhart County Solar Project, LLC	Elkhart, Indiana	100	PPA	Redacted	LCOE	30 Years	Solar	3/10/2022	8/30/2023			12/31/2025	
I&M	Mayapple Solar Holdings, LLC	Pulaski, Indiana	224	PSA	Redacted	LCOE	Company Owned	Solar	3/10/2022	8/30/2023			5/31/2026	
I&M	Sculpin Solar, LLC	DeKalb, Indiana	180	PPA	Redacted	LCOE	30 years	Solar	3/10/2022	8/30/2023			12/31/2025	
DTE	Big Turtle 2 Wind Park	Huron	29.4	VGP	$48-$50/MWh	LCOE	Company-owned	Wind	Unsolicited	3/24/2023			4/1/2023	
Consumers	Addle Solar	Hillsdale	20	PURPA	see contract		20 Years	Solar		10/27/2022			7/4/2024	
Consumers	Copenhagen Solar	Saginaw	20	PURPA	see contract		20 Years	Solar		10/27/2022			7/4/2024	
Consumers	Holly Solar	Oakland	20	PURPA	see contract		20 Years	Solar		10/27/2022			4/5/2025	
Consumers	Olivier Solar	Lenawee	20	PURPA	see contract		20 Years	Solar		10/27/2022			4/5/2025	
Consumers	Puck Solar	Ionia	20	PURPA	see contract		20 Years	Solar		10/27/2022			7/4/2024	
Consumers	Shoreline Solar	St. Joseph	20	PURPA	see contract		20 Years	Solar		10/27/2022			4/5/2025	
Consumers	Sunbelievable Solar	Clinton	12	PURPA	see contract		20 Years	Solar		10/27/2022			7/4/2024	
DTE	Gratiot Co-Location Solar Park	Gratoit	50	VGP	$59-63/MWh	LCOE	Company-owned	Solar	4/1/2022	10/27/2022			12/31/2023	
DTE	Pine River Co-Location Solar Park	Gratiot	80	VGP	$52-54/MWh	LCOE	Company-owned	Solar	4/1/2022	10/27/2022			12/31/2023	
DTE	Polaris Co-Location Solar Park	Gratiot	100	VGP	$56-59/MWh	LCOE	Company-owned	Solar	4/1/2022	10/27/2022			12/31/2023	
DTE	Sauk Solar	Branch	150	VGP	$45-47/MWh	LCOE	Company-owned	Solar	4/1/2022	10/27/2022			12/31/2023	
Consumers	Blue Elk Solar II Plant	Ingham	20	PURPA	see contract	negotited rates based on avoided cost	20 Years	Solar		10/5/2022			9/15/2023	
Consumers	Confluence Solar	Genesee & Saginaw	150	IRP	$49.85 MWh	LCOE	25-Years	Solar	9/24/2021	10/5/2022			12/31/2024	
Consumers	Heartwood Solar	Hillsdale	150	IRP	$49.85 MWh	LCOE	25-Years	Solar	9/24/2021	10/5/2022			12/31/2024	
Consumers	Morrow Plant	Kalamazoo	0.88	PURPA	see contract	Full avoided cost	5 years	Hydroelectric		4/25/2022				
Alpena	Eagle Creek Development Holdings, LLC	Various	"Bulk of RECs needed to meet the RPS"	REP	Redacted	REC pricing	3 Years	Misc.	2021	1/20/2022			12/9/2021	
Consumers	MAP Plant	Kent	0.375	PURPA	see contract	LMP energy rates, PRA capacity rates	10 years	Solar		1/20/2022			12/16/2019	
Consumers	Cereal City Solar	Calhoun	100	IRP	$51.38/MWh; *$47.99 w/o FCM*	Average Cost	25 years	Solar	2020 RFP	11/18/2021			5/31/2023	
Consumers	Jackson County Solar	Jackson	125	IRP	$54.89/MWh	LCOE	20 years	Solar	2020 RFP	11/18/2021	1/19/2023	12/21/2023	11/30/2025	12/31/2023

Consumers	SCHS Solar	Kent	0.55	PURPA	see contract	LMP energy rates, PRA capacity rates	10 years	Solar		11/18/2021		10/1/2021	
Consumers	Washtenaw Solar	Washtenaw	150	IRP	$54.46/MWh	Average Cost	Company Owned	Solar	2020 RFP	11/18/2021		12/31/2023	
Consumers	DSC Corp Center Solar Plant	Bay	0.0313	PURPA	see contract	Full avoided cost	10 years	Solar		11/4/2021		9/4/2021	
Consumers	Heathlands Solar	Manistee	30	IRP	$41.72/MWh; $39.41 w/o FCM	Average Cost	20 years	Solar	2020 RFP	9/9/2021		12/31/2022	
Alpena	Four Mile	Alpena	2.08	PURPA	see contract		3 years +	Hydroelectric	Unsolicited	7/2/2021		12/1/1913	
Alpena	Hillman	Montmorency	0.25	PURPA	see contract		3 years +	Hydroelectric	Unsolicited	7/2/2021		12/1/1944	
Alpena	Ninth Street	Alpena	1.2	PURPA	see contract		3 years +	Hydroelectric	Unsolicited	7/2/2021		12/1/1910	
Alpena	Norway Point	Alpena	4	PURPA	see contract		3 years +	Hydroelectric	Unsolicited	7/2/2021		12/1/1924	
DTE	Calhoun County Solar	Calhoun	100	VGP	$52.46/MWh	LCOE	25 years	Solar		6/9/2021		Cancelled	12/31/2022
DTE	Freshwater Solar	Montcalm	200	VGP	$48-51/MWh	LCOE	Company-owned	Solar		6/9/2021		Cancelled	12/31/2022
DTE	Whitetail Solar	Washtenaw	120	VGP	$51-54/MWh	LCOE	Company-owned	Solar		6/9/2021		Cancelled	12/31/2022
Consumers	Calhoun Solar Energy	Calhoun	140	IRP	$57.73/MWh; $54.53 w/o FCM	Average Cost	25 years	Solar	2019 RFP	4/8/2021		Delayed	5/31/2022
Consumers	Mustang Mile	Lenawee	150	IRP	$66.51/MWh	Average Cost	Company Owned	Solar	2019 RFP	4/8/2021		12/31/2022	
Consumers	Heartland Farms Wind Project	Gratiot	200	REP	$56/MWh	LCOE	Company owned	Wind	2018 RFP	3/19/2021		12/31/2022	
Consumers	MCV Plant	Midland	1240	PURPA	see contract		10 years	Cogeneration		3/4/2021		3/4/2021	
Consumers	Byron Center Plant	Kent	3	PURPA	see contract		20 years	Landfill Gas		2/4/2021		6/1/2019	
Consumers	Coopersville Plant	Ottawa	6.1	PURPA	see contract		20 years	Landfill Gas		2/4/2021		6/1/2019	
Consumers	Grand Blanc Plant	Genesee	3.8	PURPA	see contract		20 years	Landfill Gas		2/4/2021		6/1/2019	
Consumers	Michigan Wind 1 Amendment	Huron	12	REP			7 years	Wind	Amendment	2/4/2021			
Consumers	Pinconning Plant	Bay	3	PURPA	see contract		20 years	Landfill Gas		2/4/2021		6/1/2019	
Consumers	Alverno Hydro Plant	Cheboygan	1.2	PURPA	see contract		20 years	Hydroelectric		7/23/2020		6/1/2019	
Consumers	Bellevue Gothic Mill Plant	Eaton	0.045	PURPA	see contract		20 years	Hydroelectric		7/23/2020		6/1/2019	
Consumers	Cascade Hydro Plant	Kent	1.4	PURPA	see contract		20 years	Hydroelectric		7/23/2020		1/1/2019	
Consumers	City of Beaverton Hydro Plant	Gladwin	0.5	PURPA	see contract		20 years	Hydroelectric		7/23/2020		6/1/2019	
Consumers	Elk Rapids Hydro Plant	Antrim	0.7	PURPA	see contract		20 years	Hydroelectric		7/23/2020		10/13/2019	
Consumers	Fallasburg Hydro Plant	Kent	0.85	PURPA	see contract		20 years	Hydroelectric		7/23/2020		6/1/2019	
Consumers	Kleber Hydro Plant	Cheboygan	1.2	PURPA	see contract		20 years	Hydroelectric		7/23/2020		1/1/2020	
Consumers	Mass Burn Incinerator Plant	Kent	18.2	PURPA	see contract		20 years	Incinerator		7/23/2020		6/1/2019	
Consumers	Tower Hydro Plant	Cheboygan	0.56	PURPA	see contract		20 years	Hydroelectric		7/23/2020		1/1/2020	
Consumers	White's Bridge Hydro Plant	Ionia	0.817	PURPA	see contract		20 years	Hydroelectric		7/23/2020		6/1/2019	
I&M	South Bend Solar Project	St. Joseph County, Indiana	20 MW (3 MW MI Jurisdictional)	REP	$77.58/MWh	LCOE	30 Years	Solar	Competitive Solicitation	7/23/2020		4/1/2021	
DTE	Assembly Solar	Shiawassee	79	REP	$47-50/MWh	LCOE	25 Years	Solar	9/1/2019	7/9/2020		Year 2022	
DTE	Meridian Wind Farm	Saginaw	224.9	REP	$46-49/MWh	LCOE	Company-owned	Wind	9/1/2019	7/9/2020		4/18/2023	
DTE	Riverfork Solar II	Calhoun	49	REP	$49-52/MWh	LCOE	25 Years	Solar	9/1/2019	7/9/2020	1/27/2022	12/31/2023	12/31/2022
Consumers	Allegheny, LLC	Saginaw	10.699	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar	Amendment	4/15/2020	10/27/2022	7/29/2024	
Consumers	Aluminum Solar, LLC	Calhoun	8	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar	Amendment	4/15/2020	10/27/2022	11/28/2024	
Consumers	Arthur Solar Farm, LLC Plant	Midland	1.827	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar		4/15/2020		1/1/2021	
Consumers	Blue Elk Solar I, LLC	Lenawee	20	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar	Amendment	4/15/2020	10/5/2022	5/1/2024	

Consumers	Blue Elk Solar III, LLC	Lenawee	20	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar		4/15/2020		5/5/2023
Consumers	Blue Elk Solar IV, LLC	Lenawee	20	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar		4/15/2020		5/5/2023
Consumers	Blue Elk Solar VII, LLC	Genesee	12.331	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar		4/15/2020		5/5/2023
Consumers	Byrne Solar, LLC	Genesee	5	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar	Amendment	4/15/2020	10/27/2022	5/1/2023
Consumers	Golden Solar Farm, LLC Plant	Livingston	1.828	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar		4/15/2020		1/1/2021
Consumers	Greenstone Solar, LLC	Branch	20	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar		4/15/2020		5/5/2023
Consumers	Hogan Solar, LLC	Livingston	12	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar	Amendment	4/15/2020	10/27/2022	11/28/2024
Consumers	Johnsfield Solar, LLC	Midland	10	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar	Amendment	4/15/2020	10/27/2022	7/29/2024
Consumers	Lightfoot Solar, LLC	Oscada	10	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar	Amendment	4/15/2020	10/27/2022	6/1/2023
Consumers	Lyons Road Solar Farm, LLC	Shiawassee	20	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar		4/15/2020		9/1/2021
Consumers	Midcontinent Solar, LLC	Shiawassee	20	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar		4/15/2020		5/5/2023
Consumers	Robert Swift Solar Farm, LLC Plant	Branch	1.828	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar		4/15/2020		1/1/2021
Consumers	Shipsterns Solar, LLC	Calhoun	20	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar	Amendment	4/15/2020	10/27/2022	7/1/2023
Consumers	Surbrook Solar, LLC	Jackson	10	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar	Amendment	4/15/2020	10/27/2022	1/30/2024
Consumers	TART Solar, LLC	Grand Tranverse	8.49	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar	Amendment	4/15/2020	6/23/2021	7/1/2022
Consumers	Topanga Solar, LLC	Arenac	20	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar	Amendment	4/15/2020	10/27/2022	1/30/2024
Consumers	Willford Solar, LLC	Gladwin	20	PURPA	see contract	Avoided energy rates, PRA capacity rates	20 years	Solar	Amendment	4/15/2020	10/27/2022	12/1/2023
Consumers	Cement City Solar, LLC	Jackson	20	PURPA	see contract	Full avoided cost	20 years	Solar	Amendment	12/19/2019	1/20/2022	7/1/2022
Consumers	Letts Creek Solar, LLC	Jackson	15	PURPA	see contract	Full avoided cost	20 years	Solar	Amendment	12/19/2019	1/20/2022	8/1/2022
Consumers	Pullman Solar, LLC	Allegan	20	PURPA	see contract	Full avoided cost	20 years	Solar	Amendment	12/19/2019	1/20/2022	7/1/2022
Consumers	Thorn Lake Solar, LLC	Washtenaw	20	PURPA	see contract	Full avoided cost	20 years	Solar	Amendment	12/19/2019	1/20/2022	9/15/2024
Consumers	13 Mile Solar, LLC	Calhoun	2	PURPA	see contract	Full avoided cost	20 years	Solar		12/6/2019		8/18/2020
Consumers	Angola Solar, LLC	Branch	2	PURPA	see contract	Full avoided cost	20 years	Solar		12/6/2019		8/18/2020
Consumers	Bingham Solar, LLC	Clinton	20	PURPA	see contract	Full avoided cost	20 years	Solar		12/6/2019		11/30/2020

Consumers	Bullhead Solar, LLC	Hillsdale	2	PURPA	see contract	Full avoided cost	20 years	Solar	Amendment	12/6/2019	7/9/2020		10/15/2020	
Consumers	Captain Solar, LLC	Genesee	2	PURPA	see contract	Full avoided cost	20 years	Solar		12/6/2019			8/3/2020	
Consumers	Coldwater Solar, LLC	Genesee	2	PURPA	see contract	Full avoided cost	20 years	Solar		12/6/2019			8/3/2020	
Consumers	Crescent Wind	Hillsdale	166	REP	$48/MWh	LCOE	Company Owned	Wind	6/1/2018	12/6/2019	10/7/2019		2/15/2021	12/31/2020
Consumers	Geddes 1 Solar, LLC	Saginaw	2	PURPA	see contract	Full avoided cost	20 years	Solar	Amendment	12/6/2019	7/9/2020		10/15/2020	
Consumers	Geddes 2 Solar, LLC	Saginaw	2	PURPA	see contract	Full avoided cost	20 years	Solar	Amendment	12/6/2019	7/9/2020		10/15/2020	
Consumers	Good Fruit Storage, LLC	Ottawa	0.179	PURPA	see contract	LMP energy rates, PRA capacity rates	10 years	Solar	Amendment	12/6/2019	2/18/2021		9/30/2020	
Consumers	Hazel Solar, LLC	Montcalm	2	PURPA	see contract	Full avoided cost	20 years	Solar		12/6/2019			8/18/2020	
Consumers	Hendershot Solar, LLC	Lenawee	2	PURPA	see contract	Full avoided cost	20 years	Solar		12/6/2019			8/18/2020	
Consumers	Interchange Solar, LLC	Genesee	2	PURPA	see contract	Full avoided cost	20 years	Solar		12/6/2019			8/18/2020	
Consumers	Jack Francis Solar, LLC	Genesee	2	PURPA	see contract	Full avoided cost	20 years	Solar		12/6/2019			8/3/2020	
Consumers	Lake City Solar	Missaukee	2	PURPA	see contract	Full avoided cost	20 years	Solar	Amendment	12/6/2019	10/29/2020	10/5/2022	9/30/2023	
Consumers	Macbeth Solar, LLC	Muskegon	20	PURPA	see contract	Full avoided cost	20 years	Solar		12/6/2019			12/24/2021	
Consumers	May Shannon Solar, LLC	Genesee	2	PURPA	see contract	Full avoided cost	20 years	Solar		12/6/2019			8/3/2020	
Consumers	Morey Road Solar	Missaukee	2	PURPA	see contract	Full avoided cost	20 years	Solar	Amendment	12/6/2019	10/29/2020	10/5/2022	9/30/2023	
Consumers	Stoneheart Solar, LLC	Saginaw	2	PURPA	see contract	Full avoided cost	20 years	Solar		12/6/2019			12/8/2020	
Consumers	Surrey Road Solar	Clare	2	PURPA	see contract	Full avoided cost	20 years	Solar	Amendment	12/6/2019	10/29/2020	10/5/2022	9/30/2023	
Consumers	Temperance Solar, LLC	Monroe	20	PURPA	see contract	Full avoided cost	20 years	Solar		12/6/2019			11/30/2020	
Consumers	Woodley Solar, LLC	Branch	0.821	PURPA	see contract	Full avoided cost	20 years	Solar		12/6/2019			12/8/2020	
Consumers	Workman Road Solar	Missaukee	2	PURPA	see contract	Full avoided cost	20 years	Solar		12/6/2019			9/30/2020	
Consumers	Belding Plant	Ionia	0.3	PURPA	see contract		20 years	Hydroelectric		11/14/2019			1/1/2019	
Consumers	Mackinaw City Plant	Emmet	1.8	PURPA	see contract		2 years	Wind	Amendment	11/14/2019	9/9/2021		6/1/2019	
Consumers	LaBarge Hydro Plant	Kent	0.8	PURPA	see contract		20 years	Hydroelectric		9/26/2019			9/26/2019	
Consumers	Rathbun Plant	Saginaw	1.6	PURPA	see contract		20 years	Landfill Gas		9/26/2019			9/26/2019	
Consumers	River Fork Solar	Calhoun	100	REP	$44.16/MWh	LCOE	20 years	Solar	Amendment	9/26/2019	10/29/2019		3/31/2022 - 11/30/2022; 3/31/2022	5/31/2021
DTE	Fairbanks Wind Park	Delta	72.45	VGP	$53.78/MWh***	LCOE	Company Owned	Wind	5/59/2018	7/18/2019			1/7/2022	
DTE	Isabella I Wind Farm	Isabella	197	VGP	$43.20/MWh***	LCOE	Company Owned	Wind	5/29/2018	7/18/2019			6/1/2021	
DTE	Isabella II Wind Farm	Isabella	186	VGP	$43.20/MWh***	LCOE	Company Owned	Wind	5/29/2018	7/18/2019			6/1/2021	
Consumers	Hillman	Montmorency	16.3	PURPA	see contract		3 years	Biomass		7/2/2019			7/2/2019	
Consumers	Lincoln Plant	Alcona	18	PURPA	see contract		8 years	Biomass		4/18/2019			4/18/2019	
Consumers	McBain Plant	Missaukee	18	PURPA	see contract		8 years	Biomass		4/18/2019			4/18/2019	
Consumers	Gratiot Farms	Gratiot	150	REP	$46/MWh	LCOE	Company Owned	Wind	7/1/2017	2/7/2019			12/1/2020	
DTE	Polaris Wind Park	Gratiot	168	REP	$47.18/MWh***	LCOE	Company Owned "Polaris "	Wind	6/19/2017	4/12/2018			4/23/2020	
Consumers	Ada Hydroplant	Kent	1.4	PURPA	see contract		5 years	Hydroelectric	Amendment	7/31/2017	10/5/2022		7/31/2017	
Consumers	Cross Winds III	Tuscola	76	VGP	$46/MWh	LCOE	Company Owned	Wind	12/1/2016	3/10/2017			12/31/2019	
Consumers	Cross Winds II	Tuscola	44	VGP	$45/MWh	LCOE	Company Owned	Wind	10/2/2012	12/20/2016			12/31/2017	
DTE	Pine River Wind Energy, LLC	Gratiot & Isabella	161.3	REP	$59.67/MWh***	LCOE	Company Owned "Pine River"	Wind	5/20/2016	12/20/2016	6/9/2021		12/31/2018	
Consumers	Solar Gardens	Various	10	VGP	$160.00/MWh	LCOE	Company Owned	Solar		3/29/2016			Starting with 4/18/2016	
Consumers	Experimental Advanced Renewable Program Phases 26-35	Various	2.2	REP	$0.199-$0.243/kWh	Tariffed Program	Up to 15 years	Solar	Unsolicited	2/11/2016			Varies	
DTE	Innovatus (DTE Solar)		50.28	VGP	$54.75/MWh	LCOE	Company Owned	Solar	6/24/2015	12/11/2015			10/31/2016	

DTE	Pinnebog Wind	Huron	50	VGP	$54.75/MWh	LCOE	Company Owned	Wind	6/20/2014	12/11/2015	12/9/2016
I&M	Clean Energy Solar Pilot Project (CESPP)	Various	15.7 MW (4.6 MW in MI)	REP	$42.48/MWh	LCOE	20 Years	Solar	Competitive Solicitation	12/11/2015	10/1/2016
Consumers	Geronimo Huron Wind, LLC (Apple Blossom)	Huron	100	REP	Less than $45/MWh	LCOE	Up to 15 years	Wind	Unsolicited	11/19/2015	2017
Consumers	Experimental Advanced Renewable Program Anaerobic Digester	Various	2.6	REP	$86/MWh or $76.39/MWh-106.39/MWh	Tariffed Program	20 years	Anaerobic	Unsolicited	4/23/2015	Varies
Consumers	Experimental Advanced Renewable Program Phases 16-21	Various	1.4	REP	$0.199-$0.243	Tariffed Program	Up to 15 Years	Solar	Unsolicited	4/23/2015	Varies
DTE	Inovateus Solar, LLC. (SolarCurrents)	Wayne	0.504	REP	$3,741/kW	Average cost	Company Owned	Solar	9/28/2012	7/8/2014	4/1/2015
DTE	Rudolf Libbe, Inc	Wayne	0.75	REP	$3,741/kW	Average cost	Company Owned	Solar	9/28/2012	7/8/2014	
Consumers	Experimental Advanced Renewable Program Phases 10-15	Various	1.2	REP	Non-Residential $0.199-0.209/kWh Residential $0.243-0.249/kWh	Tariffed Program	Up to 15 Years	Solar	Unsolicited	5/2/2014	Varies
UMERC	Cadillac Renewable Energy. LLC	Various	REC-Only Redacted	REP	Redacted		Redacted	Biomass	Competitive Solicitation	1/23/2014	Redacted
Consumers	Cross Winds	Tuscola	111	REP	$59.00/MWh	LCOE	Company Owned	Solar		9/24/2013	12/31/2014
DTE	Big Turtle Wind Farm, LLC	Huron	20	REP	$53/MWh	LCOE	20 Years	Wind	Unsolicited	9/24/2013	Expected 2014
Consumers	ABB Transformers							Wind	2/27/2013	9/10/2013	
Consumers	Barton Malow Company							Wind	4/25/2013	9/10/2013	
Consumers	General Electric Company							Wind	10/2/2012	6/28/2013	
DTE	Pheasant Run Wind II, LLC	Huron	74.8	REP	Up to $49.25/MWh	LCOE	Company Owned "Brookfield"	Wind	Unsolicited	5/17/2013	12/31/2014
DTE	Pheasant Run Wind, LLC	Huron	74.8	REP	Up to $49.25/MWh	LCOE	20 Years	Wind	Unsolicited	5/17/2013	12/31/2014
DTE	SolarCurrents Phase II	Various	2	REP	$0.13/W $0.02/kWh-$0.20/W $0.03/kWh	Tariffed Program	Through 8/31/2029	Solar	Unsolicited	11/16/2012	Varies
DTE	Tuscola Wind II, LLC	Tuscola & Bay	100	REP	$49.25/MWh***	LCOE	20 Years	Wind	5/3/2012	10/31/2012	12/31/2013
DTE	Echo Wind	Huron	110	REP	$52.50/MWh	Staff estimate	Company Owned	Wind	4/17/2012	9/11/2012	12/31/2013
Consumers	Heritage Stoney Corners Wind Farm I (Phase 3)	Missaukee & Osceola	8.35	REP	$106.20/MWh	LCOE	20 Years	Wind	Result of Amendment	1/26/2012	1/1/2012
DTE	Michigan Waste Energy, Inc	Wayne	Up to 65,000 RECs/Year	REP	$7.00/REC	REC pricing	13 Years	Incinerator	Unsolicited	12/6/2011	1991
DTE	SolarCurrents	Various	12	REP	Up to $48 Million	Tariffed Program	Company Owned	Solar	3/24/2011	11/10/2011	12/31/2015
DTE	Thumb Wind (McKinley, Minden, and Sig	Huron & Sanilac	110.4	REP	$61-$64/MWh	LCOE	Company Owned	Wind	5/6/2011	9/13/2011	12/31/2010
DTE	L'Anse Warden Electric Company	Baraga	110,374 RECs	REP	$11.98 (Average of 4 REC/ACEC Contracts)	REC pricing	Amendment Acquuiring Vintage RECs	Biomass	8/18/2009	8/25/2011	7/1/2010
DTE	Tuscola Bay Wind. LLC	Tuscola, Bay, & Saginaw	120	REP	Up to $60.90/MWh	LCOE	20 Years	Wind	11/18/2010	8/25/2011	12/31/2013
I&M	Wildcat I Wind Farm, LLC	Madison and Tipton Counties, Indiana	100 MW (60MW for MI)	REP	Redacted		20 years	Wind	Competitive Solicitation	8/25/2011	12/31/2012

Consumers	Experimental Advanced Renewable Program	Various	0.9877	REP	Commercial $0.375/KWh Residential $0.525/KWh	Tariffed Program	12 Years	Solar	Unsolicited	5/10/2011		Varies	
DTE	Gratiot County Wind (Amendment)	Gratiot	12.8	REP	Unchanged from original contract		Company Owned	Wind	Amendment	5/10/2011		12/31/2012	
DTE	Blue Water Renewables - Smiths Creek Landfill	St. Clair	3.2	REP	$99.00/MWh	LCOE	20 Years	Landfill Gas	Unsolicited	1/20/2011		12/31/2011	
Consumers	Experimental Advanced Renewable Program	Various	1	REP	Commercial $0.45/KWh Residential $0.65/KWh	Tariffed Program	12 Years	Solar	Unsolicited	12/21/2010		5/1/2010	
DTE	Nova Consultants (SolarCurrents)	Various		RE	Unchanged from original contract		Company Owned	Solar	Extension	12/21/2010		12/31/2011	
Consumers	Lake Winds Energy Park U-15805 edocket files #251-256	Mason	100.8	REP	$110.00/MWh	LCOE	Company Owned	Wind	1/15/2010	12/2/2010		12/31/2012	
Consumers	Heritage Garden Wind Farm I	Delta	20	REP	$106.20/MWh	LCOE	20 Years	Wind	Amendment	11/19/2010	1/26/2012	12/31/2012	1/1/2012
Consumers	Heritage Stoney Corners Wind Farm II	Missaukee & Osceola	12.3	REP	$98.50/MWh	LCOE	20 Years	Wind	Amendment	11/19/2010	1/26/2012	1/1/2012	
DTE	Gratiot County Wind	Gratiot	89.6	REP	$94.43/MWh	LCOE	20 Years	Wind	8/18/2009	9/14/2010		5/1/2012	
DTE	L'Anse Warden Electric Company	Baraga	17	REP	$98.94/MWh		20 years	Biomass	8/18/2009	8/10/2010		7/1/2010	
DTE	WM Renewable Energy - Eagle Valley Landfill	Oakland	3.2	REP	Combined average of	LCOE	20 years	Landfill Gas	8/18/2009	8/10/2010		6/1/2011	
Consumers	Blissfield Wind (Beebe Wind)	Gratiot	81	REP	$100.88/MWh	LCOE	20 Years	Wind	Amendment	7/27/2010	1/26/2012	12/31/2012	2013
Consumers	Harvest II Wind	Huron	59.4	REP	$98.38/MWh	LCOE	20 Years	Wind	5/7/2009	7/27/2010		12/31/2012	
Consumers	Michigan Wind 2	Sanilac	90	REP	$94.00/MWh	LCOE	20 Years	Wind	5/7/2009	7/27/2010		6/30/2012	
Consumers	WM Renewable Energy - Pine Tree Acres	Macomb	12.8	REP	$98.75/MWh	LCOE	20 Years	Landfill Gas	5/7/2009	7/27/2010		6/30/2012	
DTE	Boyce Hydro**	Various	Firm 210,000 RECs w/additional 112,000 RECs dependent on generation	REP	$7.75/ REC	REC pricing	7 Years	Hydroelectric	12/23/2009	4/27/2010		3/16/2010	
DTE	Nova Consultants (SolarCurrents)	Various	3	REP	Up to $18 Million		Company Owned	Solar	11/23/2009	3/2/2010		12/31/2010	
DTE	Heritage Sustainable Energy Stoney Corners Wind Farm	Missaukee & Osceola	12.2	REP	Unchanged from original contract		20 Years	Wind	Unsolicited	12/1/2009		1/1/2011	
DTE	Sterling Planet**	Various	Firm 2,500,000 RECs	REP	of $12.46/REC	REC pricing	10 Years	Misc.	12/23/2009	12/1/2009		10/1/2009	
DTE	UPPCO**	Various	Firm 500,000 RECs	REP	Combined average price	REC pricing	7 Years	Hydroelectric	12/23/2009	12/1/2009		10/1/2009	
Consumers	Elk Rapids Hydro Electric** 1	Antrim	0.7	REP	$121.31/MWh	LCOE	10 Years	Hydroelectric	1/29/2009	10/13/2009		7/11/2009	
Consumers	Freemont Community Digester	Newaygo	3.1	REP	$139.35/MWh	LCOE	20 Years	Anaerobic	1/29/2009	10/13/2009		11/11/2012	
Consumers	NANR – Lennon	Shiawassee	1.6	REP	$137.27/MWh	LCOE	20 Years	Landfill Gas	1/29/2009	10/13/2009		12/31/2010	
Consumers	Scenic View Dairy**	Allegan		REP	$138.17/MWh	LCOE	7 Years	Anaerobic	1/29/2009	10/13/2009	10/26/2010	7/11/2009	
Consumers	WM Renewable Energy - Northern Oaks Landfill	Clare	1.6	REP	$122.39/MWh	LCOE	20 Years	Landfill Gas	1/29/2009	10/13/2009		11/11/2010	
Consumers	Zeeland**	Ottawa	1.6	REP	$122.20/MWh	LCOE	7 Years	Landfill Gas	1/29/2009	10/13/2009		7/11/2009	
Alpena	Consumers Energy	Various	"Bulk of RECs needed to meet the RPS"	REP	Consumers Energy Company's Average Cost of RECs	REC pricing	20 Years	Misc.	Unsolicited	9/15/2009		8/4/2009	
I&M	Fowler Ridge Wind Farm II	Benton County, Indiana	50 MW (7.5MW for MI)	REP	Redacted		20 Years	Wind	Unsolicited	9/15/2009		2/15/2010	
DTE	Heritage Sustainable Energy Stoney Corners Wind Farm	Missaukee & Osceola	14	REP	$116.00/MWh	LCOE	20 Years	Wind	Unsolicited	4/30/2009		12/21/2009	

Consumers	Michigan Wind 1	10 years	Wind	3/14/2005	10/18/2005	

Appendix B Solar Farm Summary

	Project Name	County	Capacity (MW)	Owner/Power Purchaser	Type	Commercial Operation Date
1	13 Mile Solar, LLC	Calhoun	2	Consumers Energy	PURPA	August 2020
2	Addle Solar	Hillsdale	20	Consumers Energy	PURPA	July 2024
3	Allegheny, LLC	Saginaw	10.699	Consumers Energy	PURPA	July 2024
4	Aluminum Solar, LLC	Calhoun	8	Consumers Energy	PURPA	November 2024
5	Angola Solar, LLC	Branch	2	Consumers Energy	PURPA	August 2020
6	Arthur Solar Farm, LLC Plant	Midland	1.827	Consumers Energy	PURPA	January 2021
7	Assembly Solar	Shiawassee	50			December 2020
8	Assembly Solar II	Shiawassee	110	MPPA/BWL		December 2021
9	Assembly Solar III	Shiawassee	79	DTE Electric	REP	2022
10	Bingham Solar, LLC	Clinton	20	Consumers Energy	PURPA	November 2020
11	Blue Elk Solar I, LLC	Lenawee	20	Consumers Energy	PURPA	May 2024
12	Blue Elk Solar II Plant	Ingham	20	Consumers Energy	PURPA	September 2023
13	Blue Elk Solar III, LLC	Lenawee	20	Consumers Energy	PURPA	May 2023
14	Blue Elk Solar IV, LLC	Lenawee	20	Consumers Energy	PURPA	May 2023
15	Blue Elk Solar VII, LLC	Genesee	12.331	Consumers Energy	PURPA	May 2023
16	Bullhead Solar, LLC	Hillsdale	2	Consumers Energy	PURPA	October 2020
17	Byrne Solar, LLC	Genesee	5	Consumers Energy	PURPA	May 2023
19	Calhoun Solar Energy	Calhoun	140	Consumers Energy	IRP	Delayed
20	Captain Solar, LLC	Genesee	2	Consumers Energy	PURPA	August 2020
92	Cedar Fields Solar Park	Clare & Gladwin	138	DTE Electric	IRP	June 2027
21	Cement City Solar, LLC	Jackson	20	Consumers Energy	PURPA	July 2022
22	Cereal City	Calhoun	100	Consumers Enegy	IRP	May 2023
23	Clean Energy Solar Pilot	Berrien	4.6	I&M	REP	October 2016
84	Coldwater River Solar	Branch	150	DTE Electric	PPA	March 2026
24	Coldwater Solar, LLC	Genesee	2	Consumers Energy	PURPA	August 2020
25	Confluence Solar	Genesee & Sagniaw	150	DTE Electric	IRP	December 2024
26	Copenhagen Solar	Saginaw	20	Consumers Energy	PURPA	July 2024
27	Demile Solar	Lapeer	28.56	DTE Electric	VGP	May 2017
28	DSC Corp Center Solar Plant	Bay	0.0313	Consumers Energy	PURPA	September 2021
85	Fish Creek Solar	Montcalm	132	DTE Electric	VGP	September 2025
93	Freshwater Solar, LLC	Montcalm	200	Consumers Energy	PPA	June 2027
30	Geddes 1 Solar, LLC	Saginaw	2	Consumers Enegy	PURPA	October 2020
31	Geddes 2 Solar, LLC	Saginaw	2	Consumers Enegy	PURPA	October 2020
32	Golden Solar Farm, LLC Plant	Livingston	1.828	Consumers Enegy	PURPA	January 2021
33	Good Fruit Storage, LLC	Ottawa	0.179	Consumers Enegy	PURPA	September 2020
34	Gratiot Co-Location Solar Park	Gratiot	50	DTE Electric	VGP	December 2023
35	Greenstone Solar, LLC	Branch	20	Consumers Enegy	PURPA	May 2023

Appendix B Solar Farm Summary

	Project Name	County	Capacity (MW)	Owner/Power Purchaser	Type	Commercial Operation Date
86	Groveland Mine Solar	Dickinson	62.5	UPPCO	IRP	December 2028
36	**Hazel Solar, LLC**	**Montcalm**	**2**	**Consumers Enegy**	**PURPA**	**August 2020**
38	Heartwood Solar	Hillsdale	150	DTE Electric	IRP	December 2024
39	**Hendershot Solar, LLC**	**Lenawee**	**2**	**Consumers Enegy**	**PURPA**	**August 2020**
40	Hogan Solar, LLC	Livingston	12	Consumers Enegy	PURPA	November 2024
41	Holly Solar	Oakland	20	Consumers Enegy	PURPA	April 2025
42	**Interchange Solar, LLC**	**Genesee**	**2**	**Consumers Enegy**	**PURPA**	**August 2020**
43	**Jack Francis Solar, LLC**	**Genesee**	**2**	**Consumers Enegy**	**PURPA**	**August 2020**
44	Jackson County Solar	Jackson	125	Consumers Enegy	IRP	November 2025
45	**Johnsfield Solar, LLC**	**Midland**	**10**	**Consumers Enegy**	**PURPA**	**July 2024**
94	Kay L. Brainerd Solar	Missaukee	0.25	DTE Electric	PURPA	2024
46	**Lake City Solar**	**Missaukee**	**2**	**Consumers Enegy**	**PURPA**	**September 2023**
47	**Letts Creek Solar, LLC**	**Jackson**	**15**	**Consumers Enegy**	**PURPA**	**August 2022**
48	**Lightfoot Solar, LLC**	**Oscada**	**10**	**Consumers Enegy**	**PURPA**	**June 2023**
87	Little Trout Solar	Presque Isle	150	DTE Electric	VGP	December 2025
49	**Lyons Road Solar Farm, LLC**	**Shiawassee**	**20**	**Consumers Enegy**	**PURPA**	**September 2021**
50	**Macbeth Solar, LLC**	**Muskegon**	**20**	**Consumers Enegy**	**PURPA**	**December 2021**
51	**MAP Plant**	**Kent**	**0.375**	**Consumers Enegy**	**PURPA**	**Decemer 2019**
52	**May Shannon Solar, LLC**	**Genesee**	**2**	**Consumers Enegy**	**PURPA**	**August 2020**
53	**Midcontinent Solar, LLC**	**Shiawassee**	**20**	**Consumers Enegy**	**PURPA**	**May 2023**
88	Mission Road Co-Location Solar	Isabella	153	DTE Electric	VGP	December 2025
54	**Morey Road Solar**	**Missaukee**	**2**	**Consumers Enegy**	**PURPA**	**September 2023**
55	**Mustang Mile**	**Lenawee**	**150**	**Consumers Enegy**	**IRP**	**December 2022**
56	Olivier Solar	Lenawee	20	Consumers Enegy	PURPA	April 2025
57	**O'Shea Solar Park**	**Wayne**	**2**	**DTE Electric**	**VGP**	**August 2017**
58	**Pine River Co-Location Solar Park**	**Gratiot**	**80**	**DTE Electric**	**VGP**	**December 2023**
59	**Polaris Co-Location Solar Park**	**Gratiot**	**100**	**DTE Electric**	**VGP**	**December 2023**
60	**Puck Solar**	**Ionia**	**20**	**Consumers Enegy**	**PURPA**	**July 2024**
61	**Pullman Solar, LLC**	**Allegan**	**20**	**Consumers Enegy**	**PURPA**	**July 2022**
89	Renegade Solar Energy, LLC	Delta	100	UMERC	PSA	December 2026
62	**River Fork Solar**	**Calhoun**	**100**	**Consumers Enegy**	**REP**	**November 2022**
63	**River Fork Solar II**	**Calhoun**	**49**	**DTE Electric**	**REP**	**December 2023**
64	**Robert Swift Solar Farm, LLC Plant**	**Branch**	**1.828**	**Consumers Enegy**	**PURPA**	**January 2021**
65	**Sauk Solar**	**Branch**	**150**	**DTE Electric**	**VGP**	**December 2023**
66	**SCHS Solar**	**Kent**	**0.55**	**Consumers Enegy**	**PURPA**	**October 2021**
67	**Shipsterns Solar, LLC**	**Calhoun**	**20**	**Consumers Enegy**	**PURPA**	**July 2023**
68	Shoreline Solar	St. Joseph	20	Consumers Enegy	PURPA	April 2025

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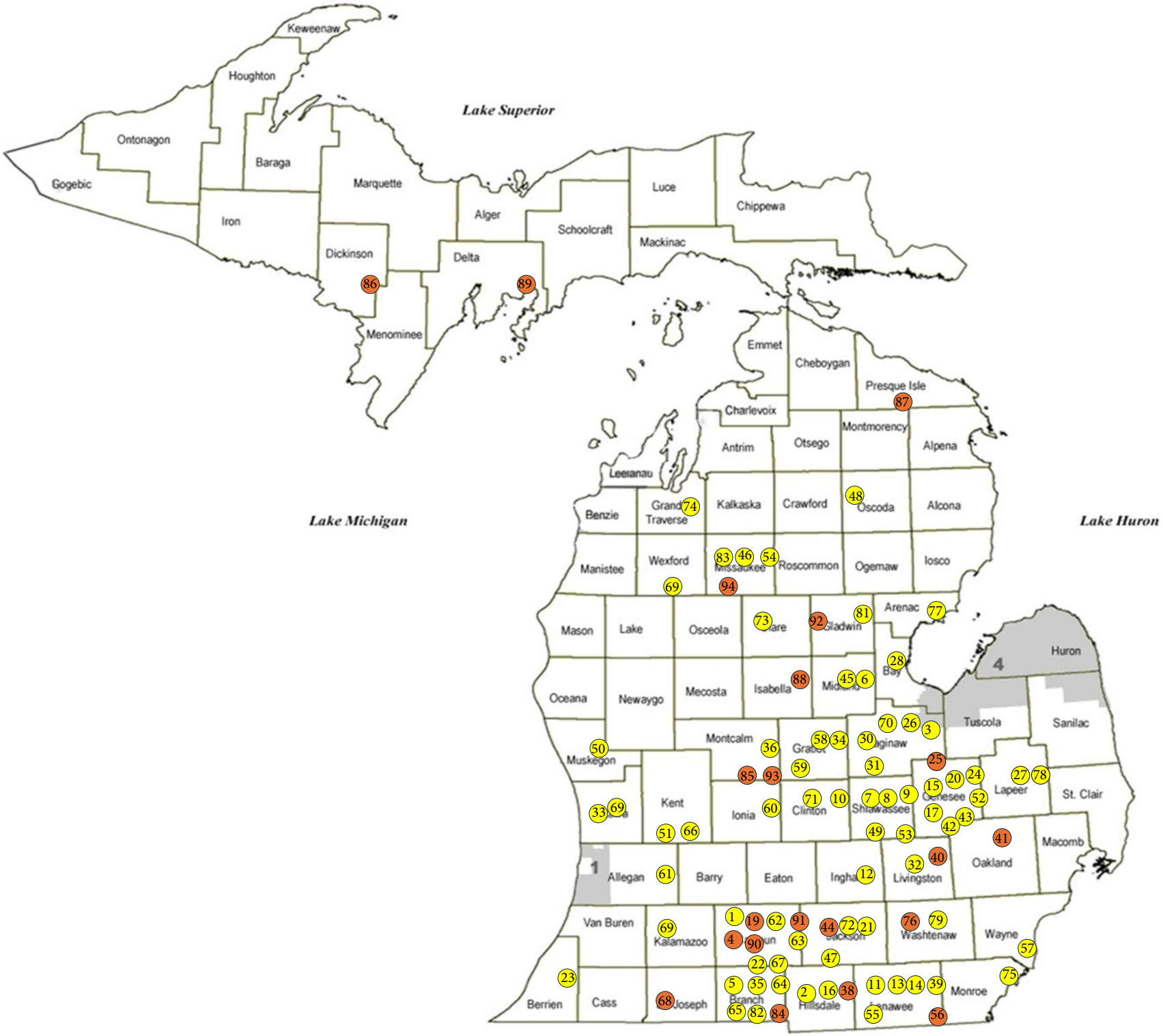
	Project Name	County	Capacity (MW)	Owner/Power Purchaser	Type	Commercial Operation Date
69	Solar Gardens, 3 sites	Ottawa, Kalamazoo, Wexford	28	Consumers Enegy	VGP	April 2016
70	Stoneheart Solar, LLC	Saginaw	2	Consumers Enegy	PURPA	December 2020
71	Sunbelievable Solar	Clinton	12	Consumers Enegy	PURPA	July 2024
90	Sunfish Solar 2 Project	Calhoun	309	Consumers Energy	VGP	December 2025
72	Surbrook Solar, LLC	Jackson	10	Consumers Enegy	PURPA	January 2024
73	Surrey Road Solar	Clare	2	Consumers Enegy	PURPA	September 2023
74	TART Solar, LLC	Grand Tranverse	8.49	Consumers Enegy	PURPA	July 2022
75	Temperance Solar, LLC	Monroe	20	Consumers Enegy	PURPA	November 2020
76	Thorn Lake Solar, LLC	Washtenaw	20	Consumers Enegy	PURPA	September 2024
77	Topanga Solar, LLC	Arenac	20	Consumers Enegy	PURPA	January 2024
78	Turrill Solar	Lapeer	19.72	DTE Electric	VGP	May 2019
79	Washtenaw Solar	Washtenaw	150	Consumers Energy	IRP	December 2023
91	White Pine Grove Solar, LLC	Calhoun	100	DTE Energy	PPA	March 2026
81	Willford Solar, LLC	Gladwin	20	Consumers Enegy	PURPA	December 2023
82	Woodley Solar, LLC	Branch	0.821	Consumers Enegy	PURPA	December 2020
83	Workman Road Solar	Missaukee	2	Consumers Enegy	PURPA	September 2020
	Totals		3,906			
	Operational Totals		1,746			

1 13 Mile Solar, LLC, 2 MW
2 Addle Solar, 20 MW
3 Allegheny, LLC, 10.699 MW
4 Aluminum Solar, LLC, 8 MW
5 Angola Solar, LLC, 2 MW
6 Arthur Solar Farm, LLC Plant, 1.827 MW
7 Assembly Solar, 79 MW
8 Assembly Solar II, 110 MW
9 Assembly Solar III, 79 MW
10 Bingham Solar, LLC, 20 MW
11 Blue Elk Solar I, LLC, 20 MW
12 Blue Elk Solar II Plant, 20 MW
13 Blue Elk Solar III, LLC, 20 MW
14 Blue Elk Solar IV, LLC, 20 MW
15 Blue Elk Solar VII, LLC, 12.331 MW
16 Bullhead Solar, LLC, 2 MW
17 Byrne Solar, LLC, 5 MW
19 Calhoun Solar Energy, 50 out of 140 MW
20 Captain Solar, LLC, 2 MW
92 Cedar Fields, 138 MW
21 Cement City Solar, LLC, 20 MW
22 Cereal City Solar, 100 MW
23 Clean Energy Solar Pilot Project (CESPP), 4.6 MW
84 Coldwater River Solar, 150 MW
24 Coldwater Solar, LLC, 2 MW
25 Confluence Solar, 150 MW
26 Copenhagen Solar, 20 MW
27 Demille Solar, 28.56 MW
28 DSC Corp Center Solar Plant, 0.0313 MW
85 Fish Creek Solar, 132 MW
93 Freshwater Solar, 200 MW
30 Geddes 1 Solar, LLC, 2 MW
31 Geddes 2 Solar, LLC, 2 MW
32 Golden Solar Farm, LLC Plant, 1.828 MW
33 Good Fruit Storage, LLC, 0.179 MW
34 Gratiot Co-Location Solar Park, 50 MW
35 Greenstone Solar, LLC, 20 MW
86 Groveland Mine Solar, 62.5 MW
36 Hazel Solar, LLC, 2 MW
38 Heartwood Solar, 150 MW
39 Hendershot Solar, LLC, 2 MW
40 Hogan Solar, LLC, 12 MW
41 Holly Solar, 20 MW
42 Interchange Solar, LLC, 2 MW
43 Jack Francis Solar, LLC, 2 MW
44 Jackson County Solar, 125 MW
45 Johnsfield Solar, LLC, 10 MW
94 Kay L. Brainerd Solar, .25 MW
46 Lake City Solar, 2 MW
47 Letts Creek Solar, LLC, 15 MW
48 Lightfoot Solar, LLC, 10 MW
87 Little Trout Solar, 150 MW
49 Lyons Road Solar Farm, LLC, 20 MW
50 Macbeth Solar, LLC, 20 MW
51 MAP Plant, 0.375 MW
52 May Shannon Solar, LLC, 2 MW
53 Midcontinent Solar, LLC, 20 MW
88 Mission Road Co-Location Solar Park, 153 MW
54 Morey Road Solar, 2 MW
55 Mustang Mile, 150 MW
56 Olivier Solar, 20 MW
57 O'Shea Solar, 2 MW
58 Pine River Co-Location Solar Park, 80 MW
59 Polaris Co-Location Solar Park, 100 MW
60 Puck Solar, 20 MW
61 Pullman Solar, LLC, 20 MW
89 Renegade Solar Energy, LLC, 100 MW
62 River Fork Solar, 100 MW
63 River Fork Solar II, 49 MW
64 Robert Swift Solar Farm, LLC Plant, 1.828 MW
65 Sauk Solar, 150 MW
66 SCHS Solar, 0.55 MW
67 Shipsterns Solar, LLC, 20 MW
68 Shoreline Solar, 20 MW
69 Solar Gardens, 28 MW
70 Stoneheart Solar, LLC, 2 MW
71 Sunbelievable Solar, 12 MW
90 Sunfish Solar 2 Project, 309 MW
72 Surbrook Solar, LLC, 10 MW
73 Surrey Road Solar, 2 MW
74 TART Solar, 8.49 MW
75 Temperance Solar, LLC, 20 MW
76 Thorn Lake Solar, LLC, 20 MW
77 Topanga Solar, LLC, 20 MW
78 Turrill Solar, 19.72 MW
79 Washtenaw Solar, 150 MW
91 White Pine Grove Solar, LLC 100 MW
81 Willford Solar, LLC, 20 MW
82 Woodley Solar, LLC, 0.821 MW
83 Workman Road Solar, 2 MW

Currently Operational
Under Development

1,746 MW Total Operational

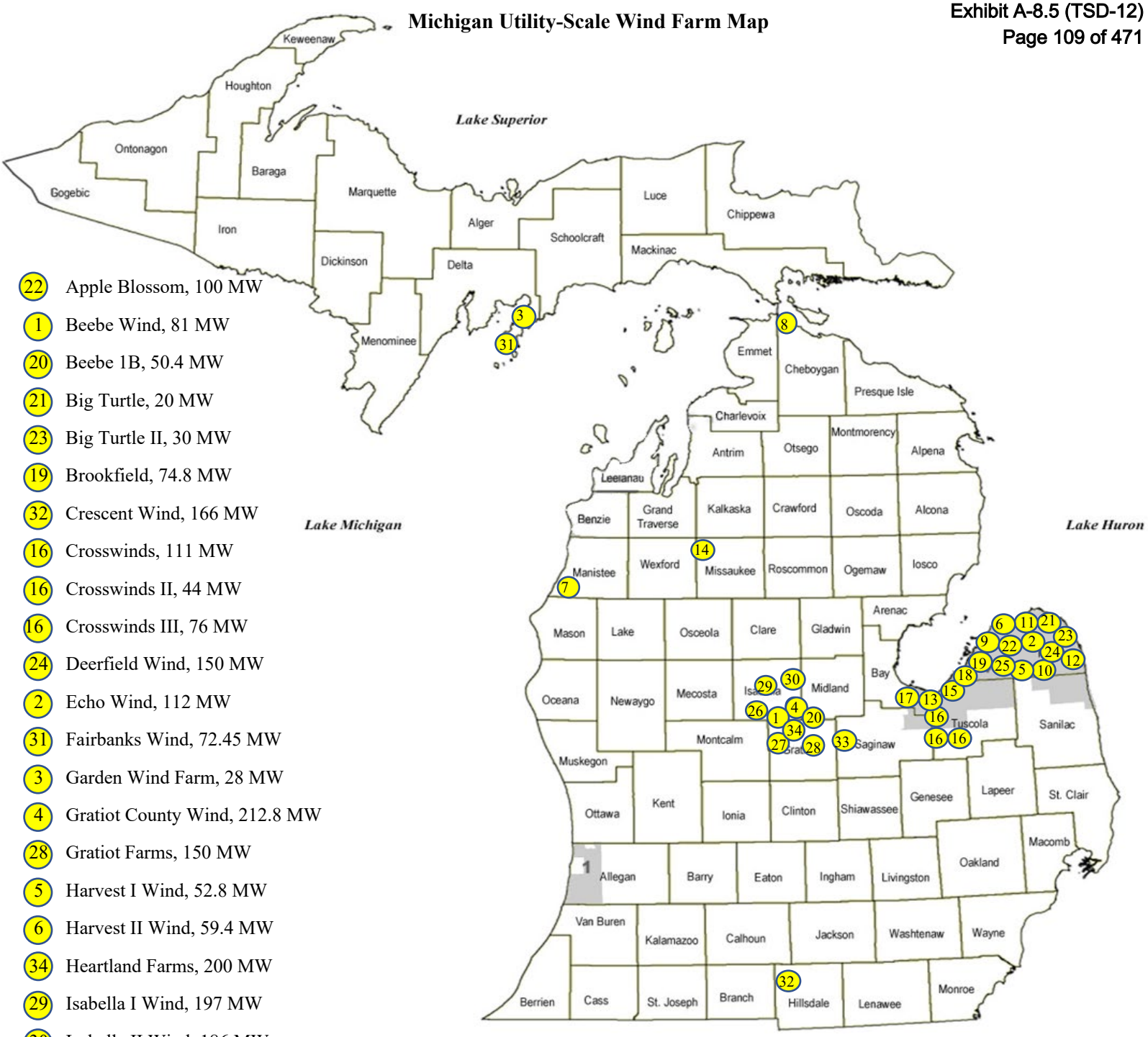

Lake Superior
Lake Michigan
Lake Huron
Keweenaw
Houghton
Ontonagon
Baraga
Gogebic
Iron
Marquette
Dickinson
Menominee
Alger
Delta
Schoolcraft
Luce
Chippewa
Mackinac
Emmet
Cheboygan
Presque Isle
Charlevoix
Antrim
Otsego
Montmorency
Alpena
Leelanau
Benzie
Grand Traverse
Kalkaska
Crawford
Oscoda
Alcona
Manistee
Wexford
Missaukee
Roscommon
Ogemaw
Iosco
Mason
Lake
Osceola
Clare
Gladwin
Arenac
Huron
Bay
Oceana
Newaygo
Mecosta
Isabella
Midland
Tuscola
Sanilac
Montcalm
Gratiot
Saginaw
Muskegon
Kent
Ionia
Clinton
Shiawassee
Genesee
Lapeer
St. Clair
Allegan
Barry
Eaton
Ingham
Livingston
Oakland
Macomb
Van Buren
Kalamazoo
Calhoun
Jackson
Washtenaw
Wayne
Berrien
Cass
St. Joseph
Branch
Hillsdale
Lenawee
Monroe
1
4

Appendix B- Wind Farm Summary

	Project Name	County	Capacity (MW)	Turbine Size (MW)	Number of Turbines	Turbine Manufacturer	Developer	Power Purchaser	Commercial Operation Date
22	Apple Blossom	Huron	100	3.45	29		Geronimo Energy	Consumers Energy	October 2017
1	Beebe	Gratiot	81	2.4	34	Nordex	Exelon & Great Lakes Wind	Consumers Energy	December 2012
20	Beebe 1B	Gratiot	50.4	2.4	21	Nordex	Exelon	Municipal Utility	December 2014
21	Big Turtle	Huron	20	2.0	10	Gamesa	Heritage Sustainable Energy	DTE	December 2014
23	Big Turtle II	Huron	30	2.0	15	Gamesa	Heritage Sustainable Energy		December 2016
19	Brookfield	Huron	74.8	1.7	44	GE Energy	NextEra Energy	DTE	February 2014
32	Crescent Wind	Hillsdale	166	2.8 & 2.3	60	GE Energy	Crescent Wind, LLC	Consumers Energy	February 2021
16	Cross Winds	Tuscola	111	1.7	65	GE Energy	Consumers Energy	N/A	December 2014
16	Cross Winds II	Tuscola	44	2.3	19	GE Energy	Consumers Energy	N/A	January 2018
16	Cross Winds III	Tuscola	76	2.3	33	GE Energy	Consumers Energy	N/A	December 2019
24	Deerfield Wind	Huron	150	2	72	Vestas	RES Americas	Wolverine Power Cooperative	January 2017
2	Echo	Huron	112	1.6	70	GE Energy	DTE	N/A	September 2014
31	Fairbanks Wind Farm	Delta	72.45	3.0	21	Siemens Gamesa	Gichi Noodin Wind	DTE	April 2021
4	Gratiot County	Gratiot	102.4	1.6	64	GE Energy	Invenergy & DTE	DTE	June 2012
28	Gratiot Farms	Gratiot	150	2	75		Tradewind Energy, Inc.	Consumers	December 2020
5	Harvest	Huron	52.8	1.65	32	Vestas	Exelon	Wolverine Power Cooperative	2008
6	Harvest II	Huron	59.4	1.8	33	Vestas	Exelon	Consumers Energy	November 2012
34	Heartland Farms	Gratiot	200	2.82 & 2.52	72	GE	Heartland Farms Wind Project, LLC	Consumers Energy	December 2022
3	Heritage Garden I	Delta	28	2.0	14	Gamesa	Heritage Sustainable Energy	Consumers Energy**	September 2012
29	Isabella I	Isabella	197	2.82	70	GE Energy	Isabella Wind, LLC	DTE	April 2021
30	Isabella II	Isabella	186	2.82	66	GE Energy	Isabella Wind, LLC	DTE	April 2021
7	Lake Winds	Mason	100.8	1.8	56	Vestas	Consumers Energy	N/A	November 2012
8	Mackinaw City	Emmet	1.8	0.9	2	NEG Micon	Mackinaw Power	Consumers Energy	2001
9	McKinley	Huron	14.4	1.6	9	GE Energy	DTE	N/A	December 2012
33	Meridian Wind Farm	Saginaw	224.9	2.82 & 3.6	77	GE Energy, Vestas	DTE	N/A	April 2023
10	Michigan Wind I	Huron	69	1.5	46	GE Energy	Exelon	Consumers Energy	2008
11	Michigan Wind II	Sanilac	90	1.8	50	Vestas	Exelon	Consumers Energy	January 2012
12	Minden	Sanilac	32	1.6	20	GE Energy	DTE	N/A	December 2012
18	Pheasant Run Wind	Huron	74.8	1.7	44	GE Energy	NextEra Energy	DTE	December 2013
26	Pine River Wind	Gratiot, Isabella	161.3	2.5	65	GE Energy	Pine River Wind Energy, LLC	DTE	December 2018
25	Pinnebog	Huron	51	1.7	30	GE Energy	DTE	DTE	December 2016
27	Polaris Wind Park	Gratiot	168	2.5 & 2.3	68	GE Energy	DTE	DTE	April 2020
15	Sigel	Huron	64	1.6	40	GE Energy	DTE	N/A	December 2012
14	Stoney Corners	Missaukee & Osceola	46.85	2 - 2.5	29	Repower, Fuhrlander, Northern Power Systems	Heritage Sustainable Energy	Consumers Energy, DTE, Traverse City Light & Power	2008 - October 2012
13	Tuscola Bay Wind	Tuscola, Bay & Saginaw	120	1.6	75	GE Energy	NextEra Energy	DTE	December 2012
17	Tuscola Wind II	Tuscola & Bay	100.3	1.7	59	GE Energy	NextEra Energy	DTE	November 2013
	Totals		3,382	MW	1,589	Turbines			
	Operational Totals		3,382	MW	1,589	Turbines			

**Heritage may supply power and RECs from this wind farm to DTE under an “additional supply” provision in a separate contract.
* Prepared by MPSC Staff and includes all wind farms operational, planned or under contract with an MPSC-rate-regulated electric provider. Additional wind farms are included as MPSC Staff becomes aware of the project.

Michigan Utility-Scale Wind Farm Map



22 Apple Blossom, 100 MW
1 Beebe Wind, 81 MW
20 Beebe 1B, 50.4 MW
21 Big Turtle, 20 MW
23 Big Turtle II, 30 MW
19 Brookfield, 74.8 MW
32 Crescent Wind, 166 MW
16 Crosswinds, 111 MW
16 Crosswinds II, 44 MW
16 Crosswinds III, 76 MW
24 Deerfield Wind, 150 MW
2 Echo Wind, 112 MW
31 Fairbanks Wind, 72.45 MW
3 Garden Wind Farm, 28 MW
4 Gratiot County Wind, 212.8 MW
28 Gratiot Farms, 150 MW
5 Harvest I Wind, 52.8 MW
6 Harvest II Wind, 59.4 MW
34 Heartland Farms, 200 MW
29 Isabella I Wind, 197 MW
30 Isabella II Wind, 186 MW
7 Lake Winds Energy Park, 100.8 MW
8 Mackinaw City, 1.8 MW
9 McKinley, 14.4 MW
33 Meridian Wind, 224.9 MW
10 Michigan Wind I, 69 MW
11 Michigan Wind II, 90 MW
12 Minden, 32 MW
18 Pheasant Run Wind, 74.8 MW
26 Pine River Wind, 161.3 MW
25 Pinnebog, 51 MW
27 Polaris Wind, 168 MW
15 Sigel, 64 MW
14 Stoney Corners, 81 MW
13 Tuscola Bay Wind, 120 MW
17 Tuscola Bay Wind II, 100.3 MW

Currently Operational
Under Development

3,382 MW Total Operational

Appendix C: MISO Planning Resource Auction Results for Planning Year 2025–2026 – April 2025

Planning Resource Auction

Results for Planning Year 2025-26

April 2025

CORRECTIONS

Reposted 05/29/25

Slides Updated: 7, 11, 18-20, 23, 32-34

MISO met the planning year 2025/26 resource adequacy requirements, but pressure persists with reduced capacity surplus across the region and is reflected through improved price signals in this year's auction

Summer
$666.50
–
Fall
$91.60 (North/Central)
$74.09 (South)
–
Winter
$33.20
–
Spring
$69.88
–
Annualized
$217 (North/Central)
$212 (South)

- MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond the seasonal Planning Reserve Margin (PRM) target
  - For example, the auction cleared 1.9% above the 7.9% summer PRM target
- Summer price reflects the lowest available surplus capacity
  - Fall price varied slightly due to transfer limitations between the North and South
- Consistent with past years, most Load Service Entities (LSEs) self-supplied or secured capacity in advance and are hedged with respect to auction prices
- Surplus above the target PRM dropped 43% compared to last summer, despite the slightly lower PRM target (7.9% vs. 9.0% last year)
  - New capacity additions did not keep pace with reduced accreditation, suspensions/retirements and slightly reduced imports
- The results reinforce the need to increase capacity, as demand is expected to grow with new large load additions

Auction outcomes are consistent with the design intent of the Reliability-Based Demand Curve (RBDC), and MISO and its members can expect more stable and predictable capacity pricing, especially in surplus situations

In the 2025 PRA, the RBDC…

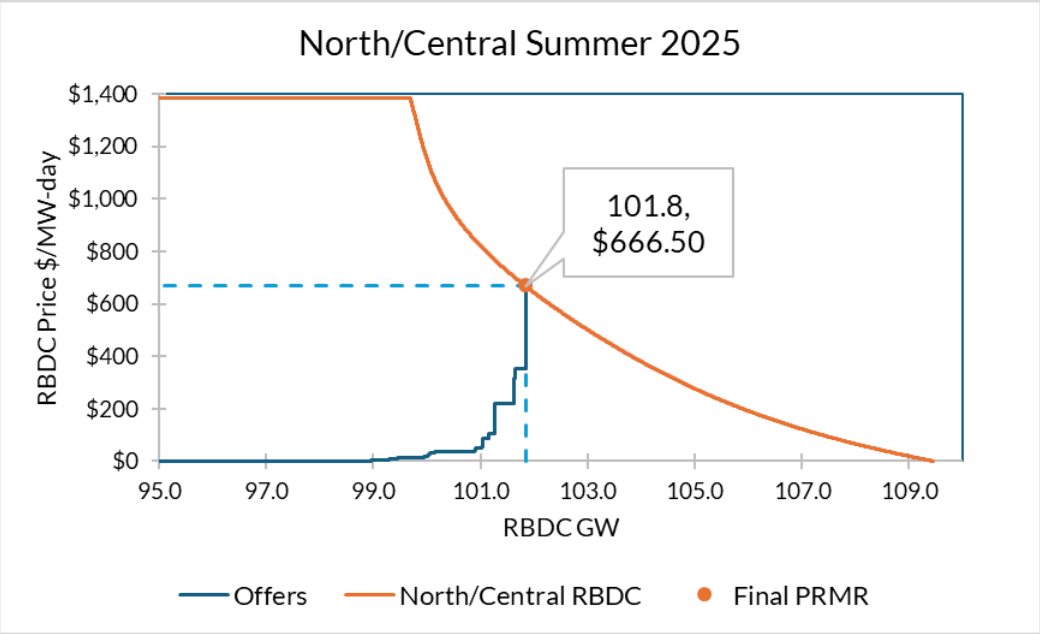
- Delivers competitive prices aligned with seasonal risks and tightening surplus
  - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
  - Clears capacity above target Planning Reserve Margin based on its reliability value in each season
- Stabilizes prices in non-summer seasons, avoiding extreme volatility

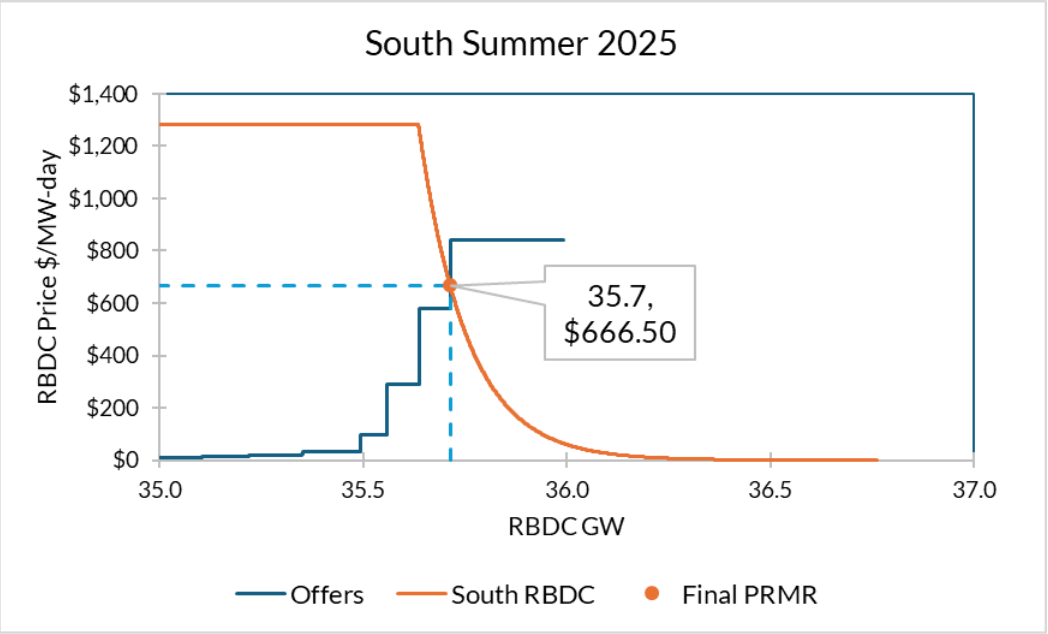
Why it Matters

- Sends clear and stable investment signals across the system, including to external resources
- Provides transparent value for capacity that exceeds the Planning Reserve Margin target
- Reflects subregional capacity needs and clears accordingly across all seasons

LOLE: Loss of Load Expectation

Auction pricing outcomes with the Reliability-Based Demand Curve (RBDC) better reflect value of capacity and resource adequacy risk across seasons





- Summer clearing of $666.50 reflects highest reliability risk and reducing surplus capacity year-over-year
  - Surplus capacity in the summer has reduced from approximately 6.5 GW in 2023, to 4.6 GW in 2024, to 2.6 GW in 2025
- Incremental capacity cleared beyond the target Planning Reserve Margin based on the value it adds to reliability (e.g., North/Central "effective" summer margin at 10.1% and South at 8.7% vs. target 7.9%)
  - A small quantity of capacity, that was offered at a price higher than the reliability value indicated through the demand curve, did not clear

LOLE: Loss of Load Expectation

MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond seasonal reliability targets

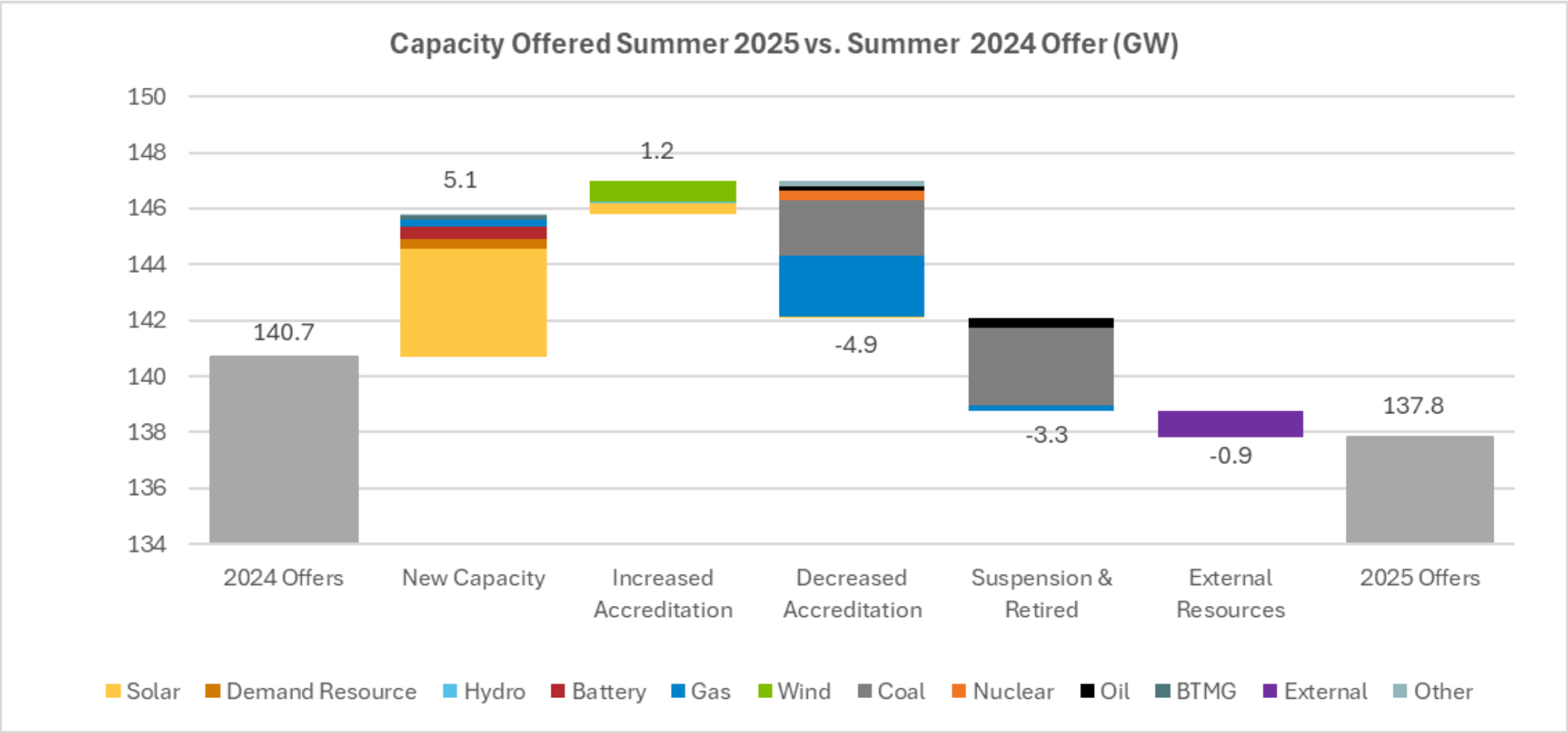
- Under RBDC, each season has an initial reliability target (PRM%)
- Auction cleared above seasonal final reliability target, representing additional reliability value at cost-competitive prices

	2025 Planning Resource Auction Initial Target vs. Final Cleared	Additional Reliability	Auction Clearing Price
Summer	Initial, 7.90% Cleared, 9.80%	+1.9%	$666.50
Fall	Initial, 14.90% Cleared, 17.50%	+2.6%	$91.60 N/C $74.09 S
Winter	Initial, 18.40% Cleared, 24.50%	+6.1%	$33.20
Spring	Initial, 25.30% Cleared, 26.80%	+1.5%	$69.88

Annualized
$217 (North/Central)
$212 (South)

PRM: Planning Reserve Margin

New capacity additions did not keep pace with decreased accreditation, suspensions/ retirements and external resources



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

MISO has taken action on many Reliability Imperative initiatives to address resource adequacy challenges, but there's more to be done

Ongoing Challenges

- Accelerating demand for electricity
- Rapid pace of generation retirements continue
- Loss of accredited capacity and reliability attributes
- Majority of new resources with variable, intermittent output and high weather correlation
- Delays of new resource additions
- More frequent extreme weather

Completed Initiatives

- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Non-emergency resource accreditation *(effective PY 2028/29)*
- ✓ Generation interconnection queue cap
- ✓ Improved generator interconnection queue process (*New application portal coming June 2025)*
- ✓ Approved over $30 billion in new transmission lines

Initiatives In Progress

- ❑ Implement Direct Loss of Load (DLOL)-based accreditation
- ❑ Enhance resource adequacy risk modeling
- ❑ Reduce queue cycle times through automation
- ❑ Implement interim Expedited Resource Addition Study (ERAS) process *(June 2025)*
- ❑ Demand Response and Emergency Resource reforms
- ❑ Enhance allocation of resource adequacy requirements

Next Steps

April 28

2025 PRA Results Posted

May 21

Zonal deliverability benefits available at the May RASC
—
MISO publishes cleared Load Modifying Resources to Operations tools

May 28

Posting of PRA masked offer data per Module E-1 69 A.7.4

June 1

2025 PRA prices go into affect
—
New Planning Year starts

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Acronyms

ACP: Auction Clearing Price

ARC: Aggregator of Retail Customers

BTMG: Behind the Meter Generator

CIL: Capacity Import Limit

CEL: Capacity Export Limit

CONE: Cost of New Entry

CPF: Coincident Peak Forecast

DLOL: Direct Loss-of-Load

DR: Demand Resource

ELCC: Effective Load Carrying Capability

EE: Energy Efficiency

ER: External Resource

ERAS: Expedited Resource Addition Study

ERZ: External Resource Zones

FRAP: Fixed Resource Adequacy Plan

ICAP: Installed Capacity

IMM: Independent Market Monitor

LBA: Load Balancing Authority

LCR: Local Clearing Requirement

LOLE: Loss of Load Expectation

LMR: Load Modifying Resource

LRR: Local Reliability Requirement

LRZ: Local Resource Zone

LSE: Load Serving Entity

OMS: Organization of MISO States

PO: Planned Outage

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

PRMR: Planning Reserve Margin Requirement

RASC: Resource Adequacy Sub-Committee

RBDC: Reliability-Based Demand Curve

SAC: Seasonal Accredited Capacity

SREC: Sub-Regional Export Constraint

SRIC: Sub-Regional Import Constraint

SRPBC: Sub-Regional Power Balance Constraint

SS: Self Schedule

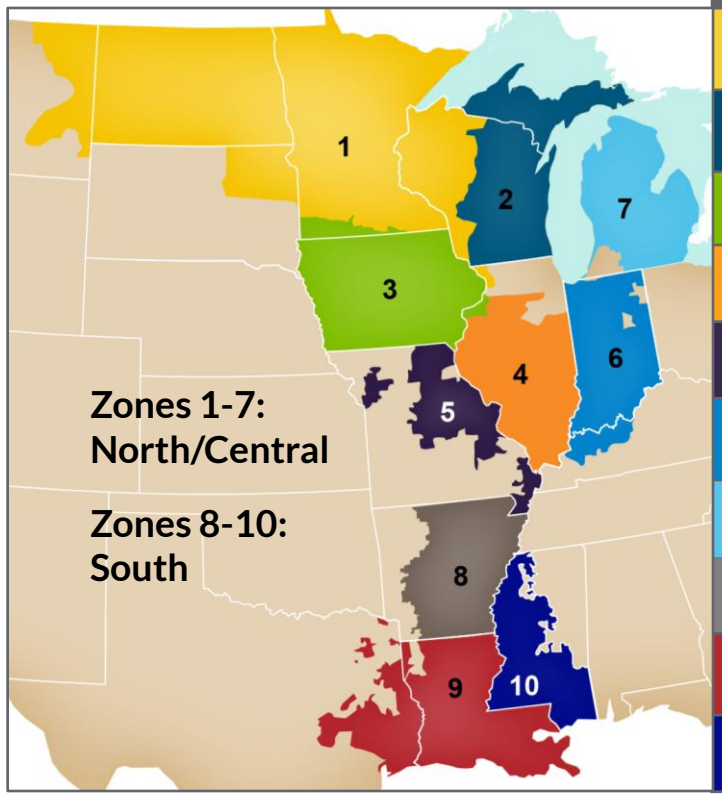
UCAP: Unforced Capacity

ZIA: Zonal Import Ability

ZRC: Zonal Resource Credit

The 2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels, with the summer price reflecting the highest risk and a tighter supply-demand balance

MISO Resource Adequacy Zones

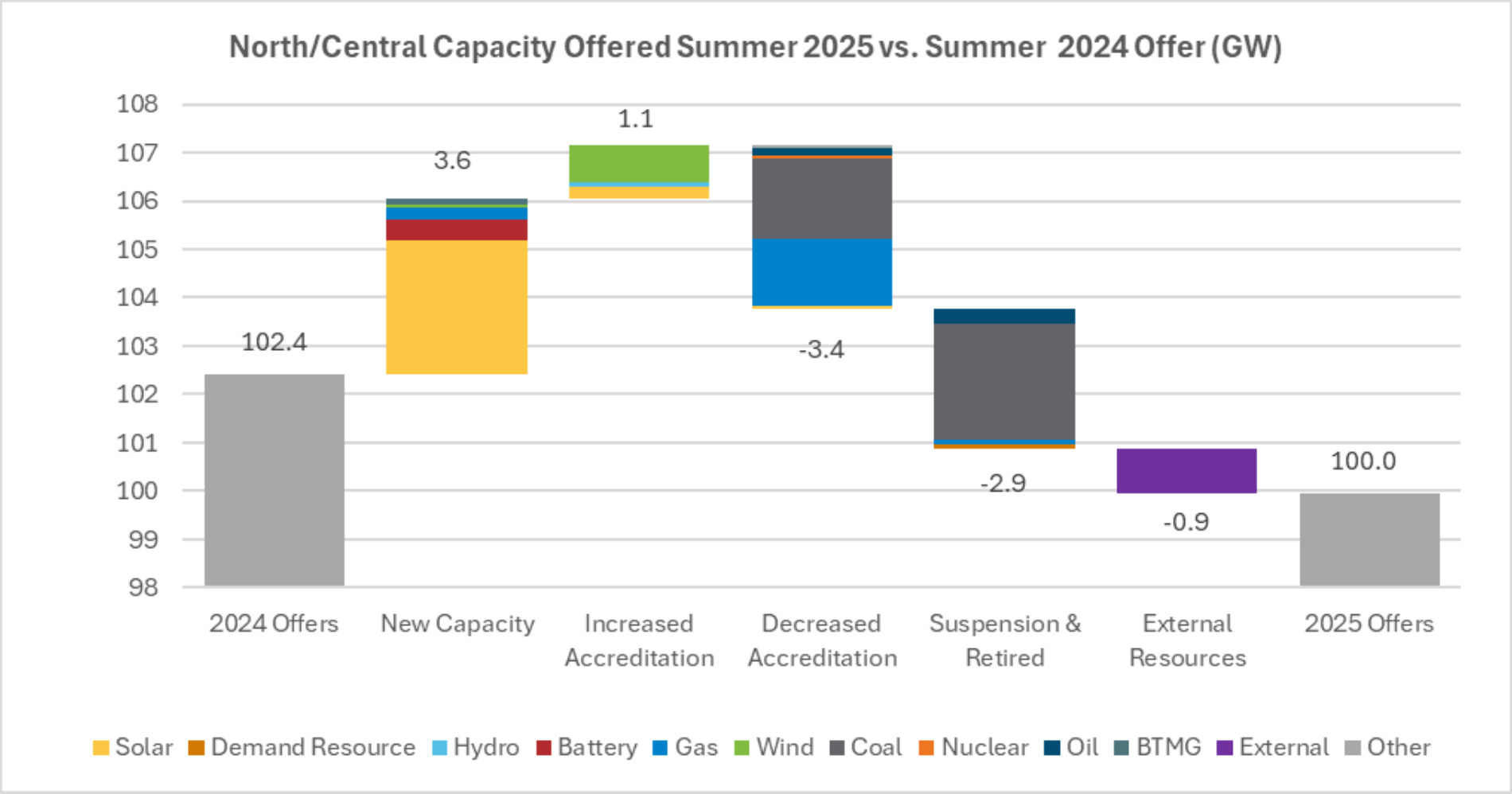


2025 PRA Results

	Price/MW-Day			
	Summer	Fall	Winter	Spring
1	$666.50	$91.60	$33.20	$69.88
2				
3				
4				
5				
6				
7				
8		$74.09		
9				
10				

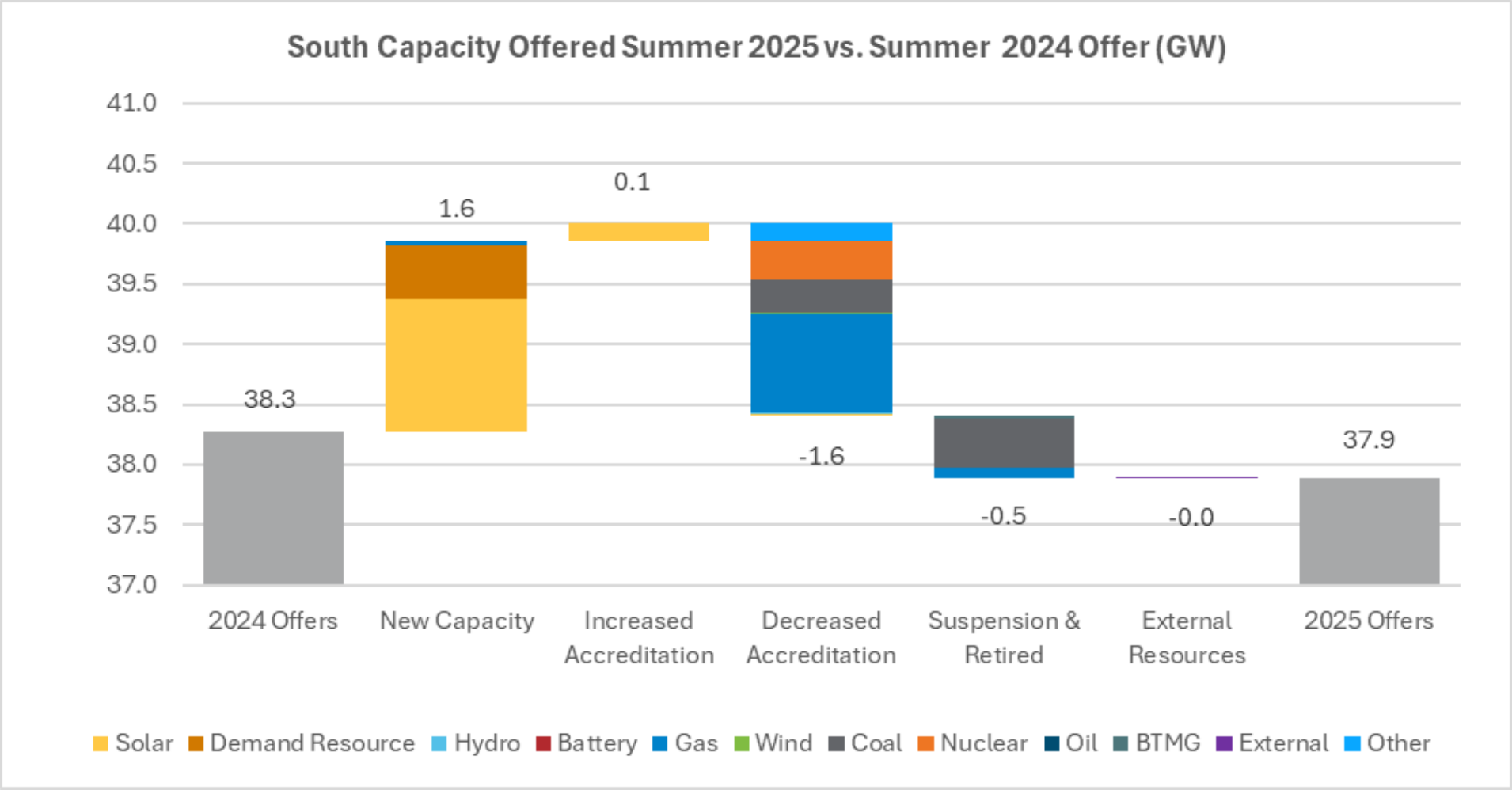
Annualized
$217 (North/Central)
$212 (South)

For North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources



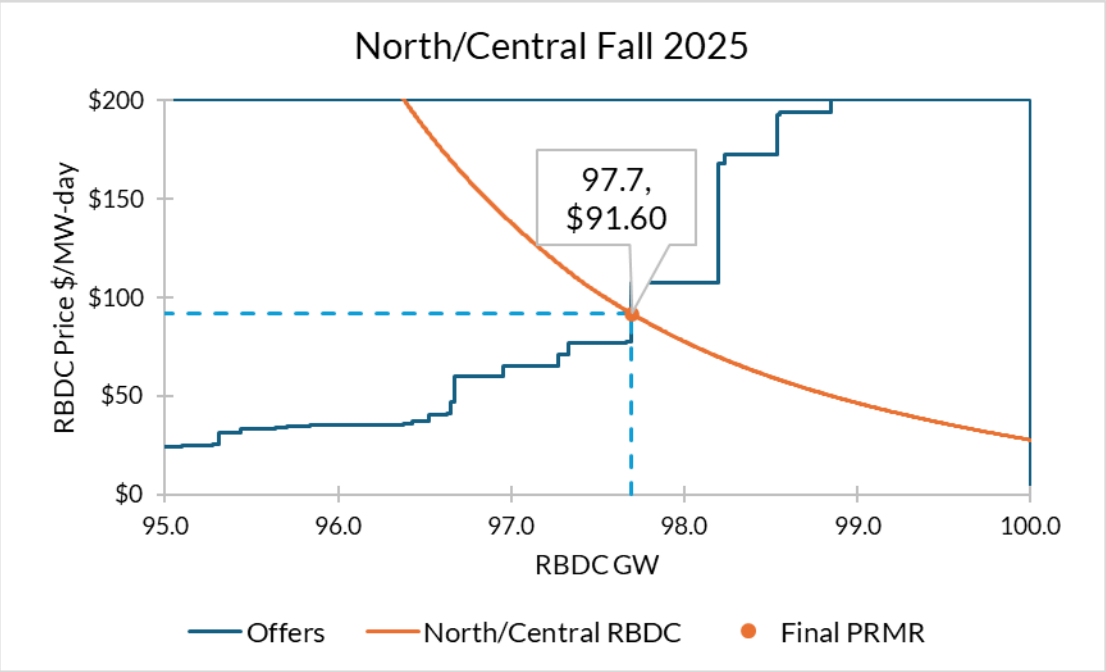
BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

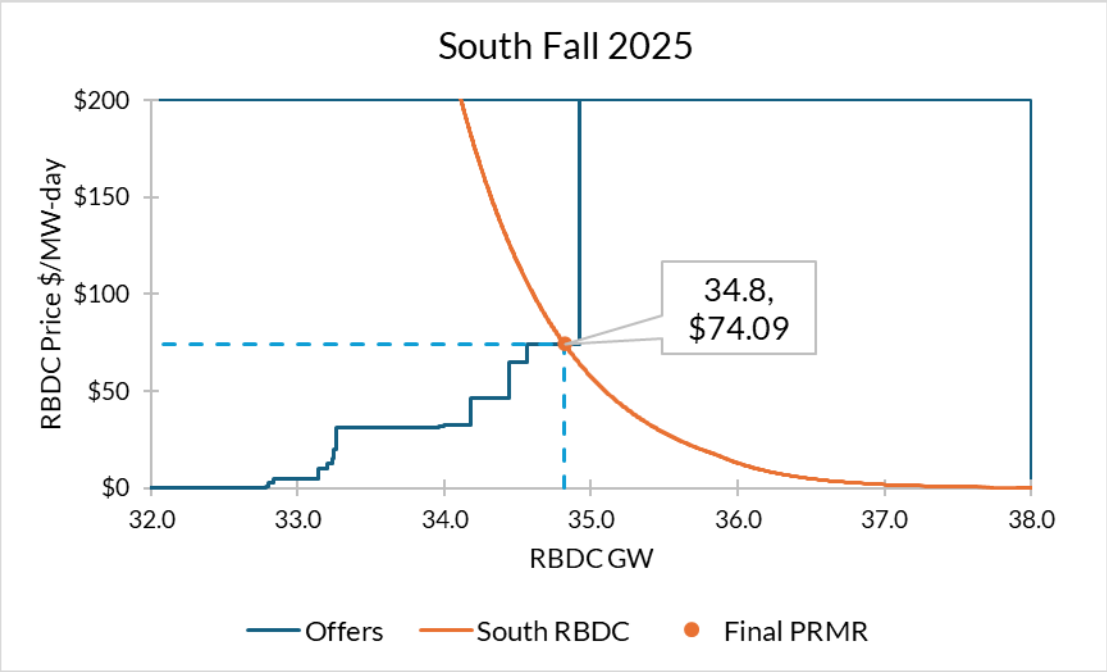
For the South, new capacity additions nearly offset the negative impacts of decreased accreditation, suspensions/retirements



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

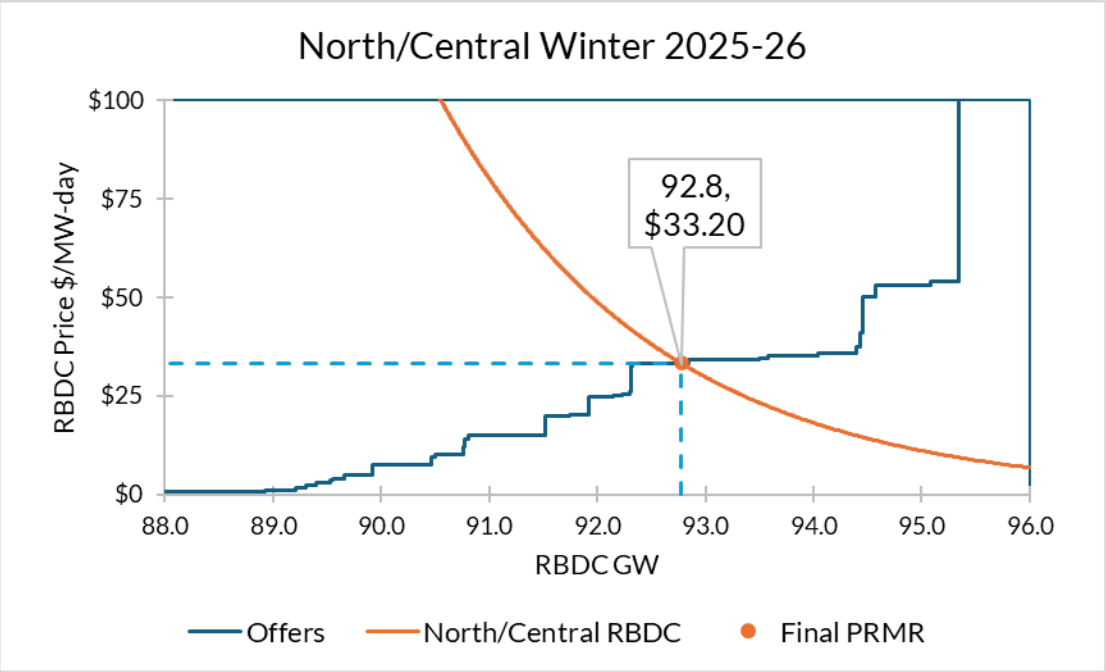
Fall 2025 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

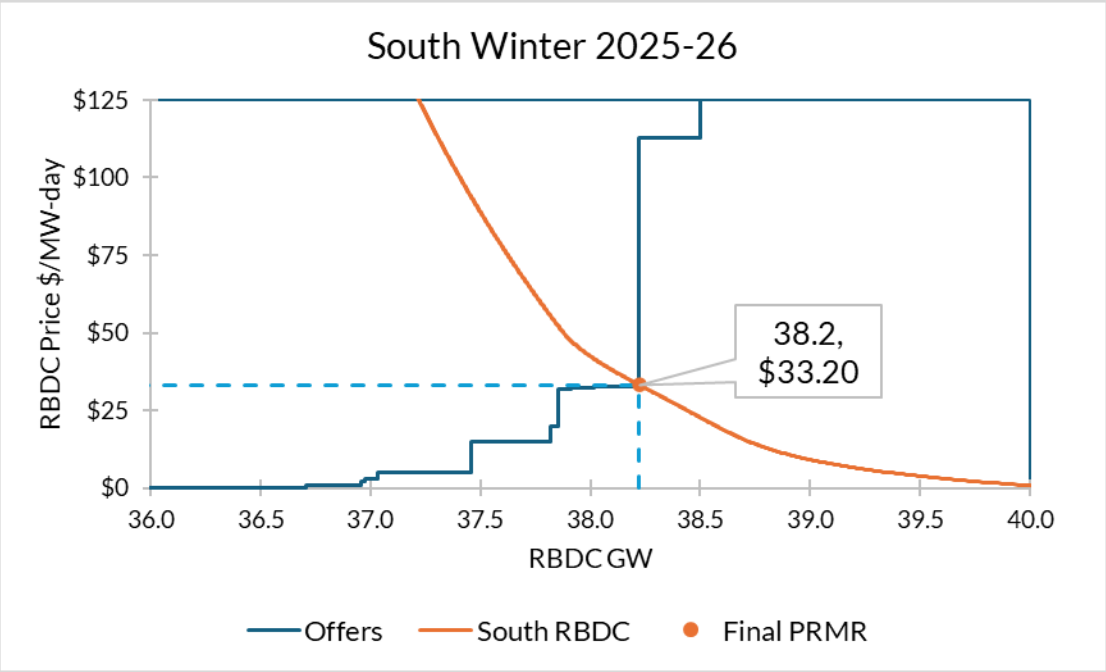




- Subregional RBDCs are determining clearing for both subregions
- Subregional Power Balance Constraint (SRPBC), South to North, is binding resulting in price separation between North/Central and South subregions in Fall season
    - ACP for North subregion is $91.60, and $74.09 South subregion
    - A marginal resource in the South sets the price in that subregion
- In fall season, “effective” margin for North/Central subregion is at 18.4% and 15.2 % for South subregion vs. target of 14.9%

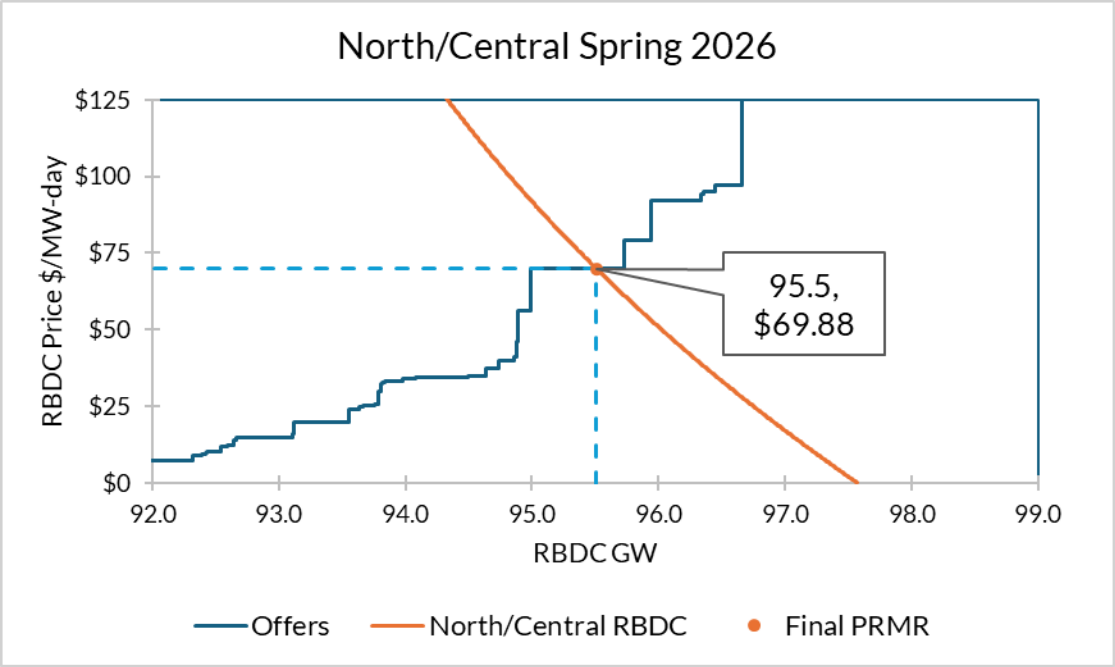
Winter 2025/26 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

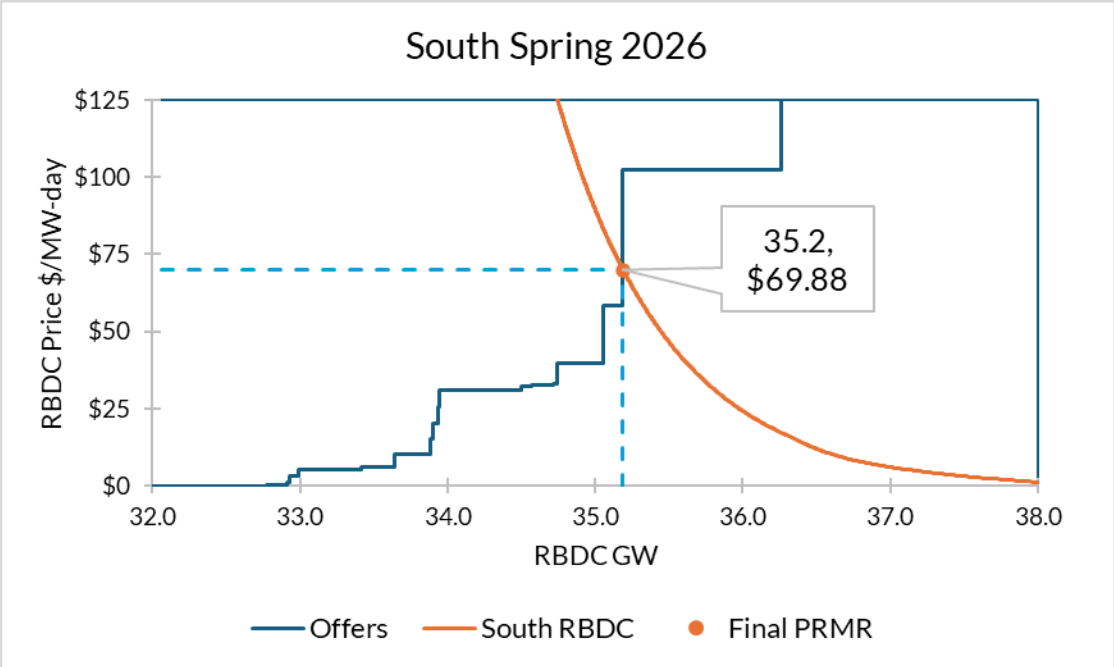




- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in winter
  - ACP for both subregions is $33.20
  - Multiple marginal resources, cleared *pro rata*, sets the price
- In winter, "effective" margin for North/Central subregion is at 23.3% and $27.3% for South subregion vs. target of 18.4%

Spring 2026 Reliability-Based Demand Curve, Offer Curves and Auction Clearing





- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in spring
  - ACP for both subregions is $69.88
  - A marginal resource sets the price
- In spring, "effective" margin for North/Central subregion is at 27.5% and 25% for South subregion vs. target of 25.3%

Summer 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	18,459.4	13,190.2	10,889.2	9,237.6	8,281.3	18,484.8	21,228.0	8,487.8	21,812.2	5,142.9	N/A	99,770.5	35,442.9	135,213.4
Final PRMR	18,843.5	13,464.4	11,116.0	9,430.10	8,453.5	18,868.9	21,669.2	8,552.6	21,978.8	5,182.3	N/A	101,845.6	35,713.7	137,559.3
Offer Submitted (Including FRAP)	19,732.4	14,569.7	11,321.4	9,328.1	6,737.9	16,123.6	20,883.9	11,517.3	20,498.6	5,543.3	1580.1	99,952.6	37,883.7	137,836.3
FRAP	4,619.2	10,252.6	456.9	789.4	0.0	1,080.7	541.3	494.9	157.5	1,507.7	46.8	17,779.2	2,167.8	19,947.0
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,985.3	3,344.1	10,450.2	7,677.2	6,647.8	11,080.3	20,305.5	10,260.6	17,870.6	3,831.3	1,358.8	65,567.6	32,244,1	97,811.7
Non-SS Offer Cleared	10,127.9	973.0	414.3	861.5	90.1	3,962.6	37.1	761.8	2,193.5	204.3	174.5	16,605.8	3,194.8	19,800.6
Committed (Offer Cleared + FRAP)	19,732.4	14,569.7	11,321.4	9,328.1	6,737.9	16,123.6	20,883.9	11,517.3	20,221.6	5,543.3	1,580.1	99,952.6	37,606.7	137,559.3
LCR	15,696.9	9,719.3	8,049.3	2,577.8	6,071.1	13,051.7	19,681.4	8,487.0	19,615.0	2,523.8	-	N/A	N/A	N/A
CIL	6,025	4,370	5,555	8,525	4,117	8,651	3,569	2,568	4,361	4,474	-	N/A	N/A	N/A
ZIA	6,023	4,370	5,460	7,757	4,117	8,366	3,569	2,358	4,361	4,474	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	101.7	1,715.5	2,745.5	785.5	0.0	1,757.1	0.0	-	1,893.0	0.0	1,580.1
CEL	3,991	4,614	4,618	4,584	3,939	6,881	5,726	6,299	4,286	2,097	-	N/A	N/A	N/A
Export	888.8	1105.2	205.5	0.0	0.0	0.0	0.0	2964.7	0.0	360.9	1,580.1	0.0	1,893.0	-
ACP ($/MW-Day)	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Fall 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,290.4	12,086.4	10,179.1	8,950.4	7,898.3	17,939.5	20,493.9	8,019.3	21,578.1	5,142.6	N/A	94,838.0	34,740.0	129,578.0
Final PRMR	17,811.9	12,450.7	10,486.0	9,220.4	8,136.0	18,480.2	21,111.9	8,037.4	21,627.1	5,154.2	N/A	97,697.1	34,818.7	132,515.8
Offer Submitted (Including FRAP)	18,893.1	14,291.7	13,615.9	8,887.5	6,839.6	15,518.1	19,517.6	11,000.8	21,112.5	5,516.6	1,582.1	98,835.3	37,940.2	136,775.5
FRAP	4,233.2	9,259.1	582.7	773.3	0.0	983.1	533.1	459.4	153.4	1,518.3	44.6	16,402.6	2,137.6	18,540.2
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,646.8	3,423.5	10,580.4	7,036.0	6,706.5	10,590.4	16,911.4	9,029.4	17,788.1	3,286.3	1,208.0	60,831.1	30,375.7	91,206.8
Non-SS Offer Cleared	9,019.0	834.8	2,452.8	1,078.2	133.1	3,728.7	1,089.1	1,512.0	2,406.6	254.9	259.6	18,563.3	4,205.5	22,768.8
Committed (Offer Cleared + FRAP)	17,899.0	13,517.4	13,615.9	8,887.5	6,839.6	15,302.2	18,533.6	11,000.8	20,348.1	5,059.5	1,512.2	95,797.1	36,718.7	132,515.8
LCR	14,691.0	6,591.1	6,331.4	2,588.7	4,857.2	11,725.4	18,196.1	5,006.3	18,963.6	2,577.6	-	N/A	N/A	N/A
CIL	5,740	6,537	7,797	7,773	4,679	8,952	5,115	5,839	4,741	4,508	-	N/A	N/A	N/A
ZIA	5,688	6,537	7,704	7,013	4,679	8,672	5,115	5,675	4,741	4,508	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	332.8	1,296.8	3,178.0	2,578.2	0.0	1,278.9	94.7	-	1,900.0	0.0	1,512.2
CEL	6,115	4,259	5,831	4,309	5,816	5,191	5,168	4,055	4,173	3,164	-	N/A	N/A	N/A
Export	87.2	1,066.8	3,129.9	0.0	0.0	0.0	0.0	2,963.3	0.0	0.0	1,512.2	0.0	1,900.0	-
ACP ($/MW-Day)	91.60	91.60	91.60	91.60	91.60	91.60	91.60	74.09	74.09	74.10	83.24-91.60			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Winter 2025/26 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,823.8	10,789.8	9,889.1	8,549.5	7,954.8	17,939.1	16,123.6	8,545.6	21,864.3	5,136.1	N/A	89,069.7	35,546.0	124,615.7
Final PRMR	18,565.8	11,238.7	10,300.9	8,905.1	8,285.9	18,685.7	16,794.7	9,189.0	23,511.0	5,522.7	N/A	92,776.8	38,222.7	130,999.5
Offer Submitted (Including FRAP)	19,750.7	13,217.2	12,059.1	7,547.1	6,339.9	14,679.5	19,957.3	10,751.9	22,273.0	5,939.7	1,746.5	94,964.8	39,297.1	134,261.9
FRAP	4,683.9	8,342.7	479.4	513.4	0.0	1,176.6	566.3	441.6	130.9	1,822.6	16.1	15,771.2	2,402.3	18,173.5
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	5,835.8	3,156.0	10,468.3	6,685.7	6,188.7	9,146.2	18,640.6	10,018.6	18,579.3	4,046.0	1,550.8	61,380.9	32,935.1	94,316.0
Non-SS Offer Cleared	7,977.9	1,062.6	1,044.5	271.5	99.9	4,008.7	397.0	291.7	3,105.5	71.1	179.6	15,007.6	3,502.4	18,510.0
Committed (Offer Cleared + FRAP)	18,497.6	12,561.3	11,992.2	7,470.6	6,288.6	14,331.5	19,603.9	10,751.9	21,815.7	5,939.7	1,746.5	92,159.7	38,839.8	130,999.5
LCR	13,462.0	5,951.6	8,008.4	1,371.4	3,644.7	11,074.8	15,500.2	8,014.7	20,593.7	3,534.1	-	N/A	N/A	N/A
CIL	6,177	6,522	5,877	7,232	4,922	7,927	4,762	3,613	4,418	3,458	-	N/A	N/A	N/A
ZIA	5,575	6,435	5,785	6,457	4,922	7,690	4,762	3,432	4,418	3,458	-	N/A	N/A	N/A
Import	68.0	0.0	0.0	1,434.8	1,997.3	4,354.1	0.0	0.0	1,695.2	0.0	-	617.1	0.0	1,746.5
CEL	2,991	4,706	7,388	4,756	4,814	1,674	5,712	3,602	3,618	2,028	-	N/A	N/A	N/A
Export	0.0	1,322.6	1,691.5	0.0	0.0	0.0	2,809.2	1,562.8	0.0	416.9	1,746.5	0.0	617.1	0.0
ACP ($/MW-Day)	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Spring 2026 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,866.7	12,149.2	10,152.2	8,304.0	7,707.9	17,858.6	19,853.2	7,977.8	22,139.8	5,167.9	N/A	93,891.8	35,285.5	129,177.3
Final PRMR	18,174.5	12,358.6	10,327.0	8,447.2	7,841.0	18,166.7	20,195.5	7,955.2	22,076.1	5,157.7	N/A	95,510.5	35,189.0	130,699.5
Offer Submitted (Including FRAP)	18,662.6	14,525.3	12,333.3	9,178.5	6,118.7	15,824.7	19,451.0	11,495.2	21,064.7	5,864.0	1,542.6	97,313.7	38,746.9	136,060.6
FRAP	4,560.6	9,393.4	529.5	629.6	0.0	1,212.4	512.5	475.3	142.1	1,464.3	45.9	16,877.1	2,088.5	18,965.6
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,600.8	3,602.8	10,816.2	7,415.0	5,968.5	9,967.6	17,621.9	8,476.0	16,778.9	4,073.9	1,260.8	60,972.6	29,609.8	90,582.4
Non-SS Offer Cleared	8,578.5	1,069.5	589.6	1,133.9	150.2	4,001.0	719.2	1,470.2	2,947.5	325.8	166.1	16,372.9	4,778.6	21,151.5
Committed (Offer Cleared + FRAP)	17,739.9	14,065.7	11,935.3	9,178.5	6,118.7	15,181.0	18,853.6	10,421.5	19,868.5	5,864.0	1,472.8	94,222.5	36,477.0	130,699.5
LCR	12,239.1	6,737.5	5,014.7	1,823.8	4,700.3	10,377.1	16,453.6	4,243.1	19,790.5	3,178.8	-	N/A	N/A	N/A
CIL	6,598	6,439	7,829	8,142	4,453	9,457	5,166	6,289	4,855	4,365	-	N/A	N/A	N/A
ZIA	6,396	6,439	7,726	7,373	4,453	9,176	5,166	6,085	4,855	4,365	-	N/A	N/A	N/A
Import	434.5	0.0	0.0	0.0	1,722.2	2,985.6	1,341.9	0.0	2,210.8	0.0	-	1,288.0	0.0	1,472.8
CEL	5,083	6,119	5,936	5,111	5,797	6,425	5,499	3,520	4,146	3,072	-	N/A	N/A	N/A
Export	0.0	1,707.2	1,608.0	731.2	0.0	0.0	0.0	2,465.6	0.0	710.3	1,472.8	0.0	1,288.0	-
ACP ($/MW-Day)	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Summer Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	Summer 2023	Summer 2024	Summer 2025	Summer 2023	Summer 2024	Summer 2025
Generation	122,375.6	123,395.6	121,015.6	116,989.7	119,479.2	120,738.6
External Resources	4,514.6	4,430.4	3,505.9	4,072.5	4,309.8	3,505.9
Behind the Meter Generation	4,175.2	4,180.2	4,282.8	4,129.4	4,143.5	4,282.8
Demand Resources	8,303.5	8,660.2	9,004.4	7,694.6	8,109.4	9,004.4
Energy Efficiency	5.0	22.5	27.6	5.0	22.5	27.6
Total	**139,373.9**	**140,688.9**	**137,836.3**	**132,891.2**	**136,064.4**	**137,559.3**

ZRC: Zonal Resource Credit

Fall Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	Fall 2023	Fall 2024	Fall 2025	Fall 2023	Fall 2024	Fall 2025
Generation	121,403.5	119,745.3	122,283.4	111,713.8	111,791.5	118,309.5
External Resources	4,095.4	4,366.8	2,833.5	3,979.6	3,990.2	2,763.6
Behind the Meter Generation	3,874.2	3,877.9	3,646.8	3,842.8	3,789.7	3,646.8
Demand Resources	6,999.2	6,866.1	7,983.7	6,254.4	5,957.5	7,767.8
Energy Efficiency	4.9	22.5	28.1	4.8	22.5	28.1
Total	**136,377.2**	**134,878.6**	**136,775.5**	**125,795.4**	**125,551.4**	**132,515.8**

ZRC: Zonal Resource Credit

Winter Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	Winter 2023-2024	Winter 2024-2025	Winter 2025-2026	Winter 2023-2024	Winter 2024-2025	Winter 2025-2026
Generation	124,632.7	133,457.4	120,225.1	114,886.6	118,253.8	117,392.0
External Resources	3,937.1	3,973.0	2,808.7	3,334.6	3,313.3	2,793.7
Behind the Meter Generation	3,257.8	3,111.5	3,082.9	3,173.9	2,957.3	3,082.6
Demand Resources	7,644.4	7,866.4	8,112.3	6,702.4	6,822.7	7,698.3
Energy Efficiency	6.7	29.7	32.9	6.7	29.7	32.9
Total	**139,478.7**	**148,438.0**	**134,261.9**	**128,104.2**	**131,376.8**	**130,999.5**

ZRC: Zonal Resource Credit

Spring Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	Spring 2024	Spring 2025	Spring 2026	Spring 2024	Spring 2025	Spring 2026
Generation	119,254.7	121,303.8	120,780.6	110,195.8	113,091.4	115,724.7
External Resources	3,794.1	3,481.8	2,640.1	3,409.1	3,406.5	2,570.3
Behind the Meter Generation	4,096.4	4,201.6	4,133.5	4,058.9	4,180.5	4,133.5
Demand Resources	7,282.9	7602.9	8,475.9	6,720.0	7,087.2	8,240.5
Energy Efficiency	5.3	25.0	30.5	5.3	25.0	30.5
Total	**134,433.4**	**136,615.1**	**136,060.6**	**124,389.1**	**127,790.6**	**130,699.5**

ZRC: Zonal Resource Credit

2025 PRA pricing compared with Independent Market Monitor (IMM) Conduct Threshold and Cost of New Entry (CONE)

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs	System CONE (Seasonal)	North/Central CONE (Seasonal)	South CONE (Seasonal)
Summer 2025	$666.50											$1,353.84	$1,384.36	$1,282.61
Fall 2025	$91.60							$74.09			$83.24-$91.60	$1,368.71	$1,399.58	$1,296.70
Winter 2025-26	$33.20											$1,383.92	$1,415.13	$1,311.11
Spring 2026	$69.88											$1,353.84	$1,384.36	$1,282.61
Cost of New Entry (Annual)	$127,720	$125,090	$121,220	$126,040	$136,170	$124,360	$130,930	$118,960	$117,710	$117,330	$136,170			
IMM Conduct Threshold*	$34.99	$34.27	$33.21	$34.53	$37.31	$34.07	$35.87	$32.59	$32.25	$32.15	-			

- *Zonal Auction Clearing Prices (ACP) shown in $/MW-day*

**Zonal Resource Credit (ZRC) offers that impact pricing should generally stay below the IMM Conduct Threshold and applies to all seasons.*

ERZ: External Resource Zones

Historical Summer Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
2015-2016	$3.48			$150.00	$3.48			$3.29		N/A	N/A
2016-2017	$19.72	$72.00						$2.99			N/A
2017-2018	$1.50										N/A
2018-2019	$1.00	$10.00									N/A
2019-2020	$2.99						$24.30	$2.99			
2020-2021	$5.00						$257.53	$4.75	$6.88	$4.75	$4.89-$5.00
2021-2022	$5.00							$0.01			$2.78-$5.00
2022-2023	$236.66							$2.88			$2.88-236.66
Summer 2023	$10.00										
Summer 2024	$30.00										
Summer 2025	$666.50										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Fall Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Fall 2023	$15.00								$59.21	$15.00	
Fall 2024	$15.00				$719.81	$15.00					
Fall 2025	$91.60							$74.09			$83.24-$91.60

- Auction Clearing Prices shown in $/MW-Day
- Price separation present in Fall 2025 between the North and South subregions since the Sub-Regional Import Constraint (SRIC) / Sub-Regional Export Constraint (SREC) bound

ERZ: External Resource Zones

Winter Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Winter 2023-24	$2.00								$18.88	$2.00	
Winter 2024-25	$0.75										
Winter 2025-26	$33.20										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Spring Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Spring 2024	$10.00										
Spring 2025	$34.10				$719.81	$34.10					
Spring 2026	$69.88										

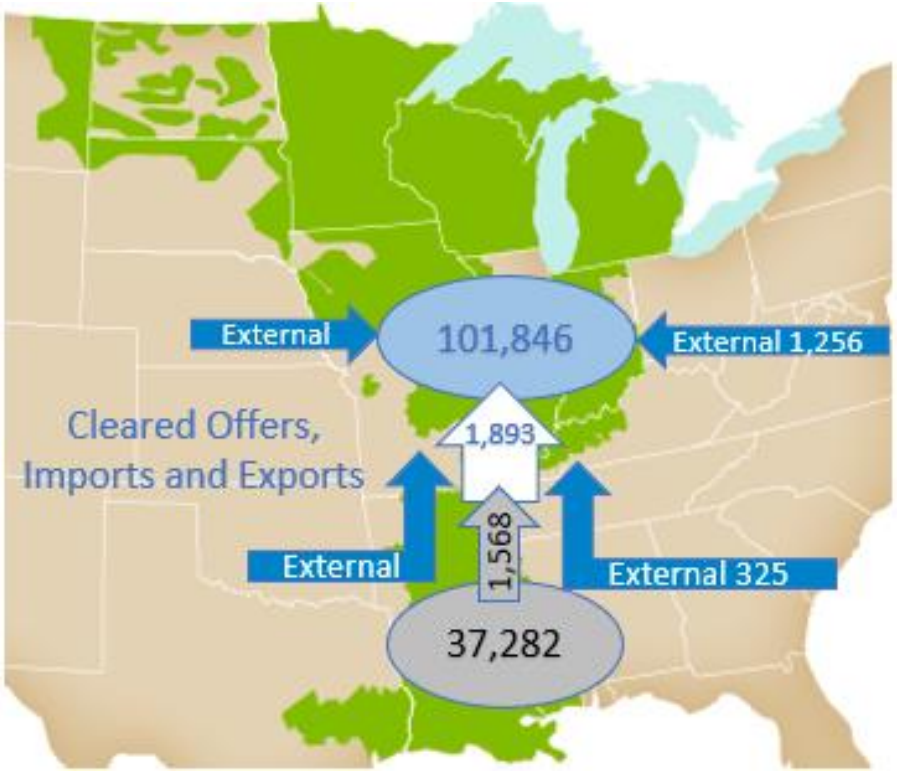
- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Summer 2025 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)



PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Fall 2025 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Winter 2025/26 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Spring 2026 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

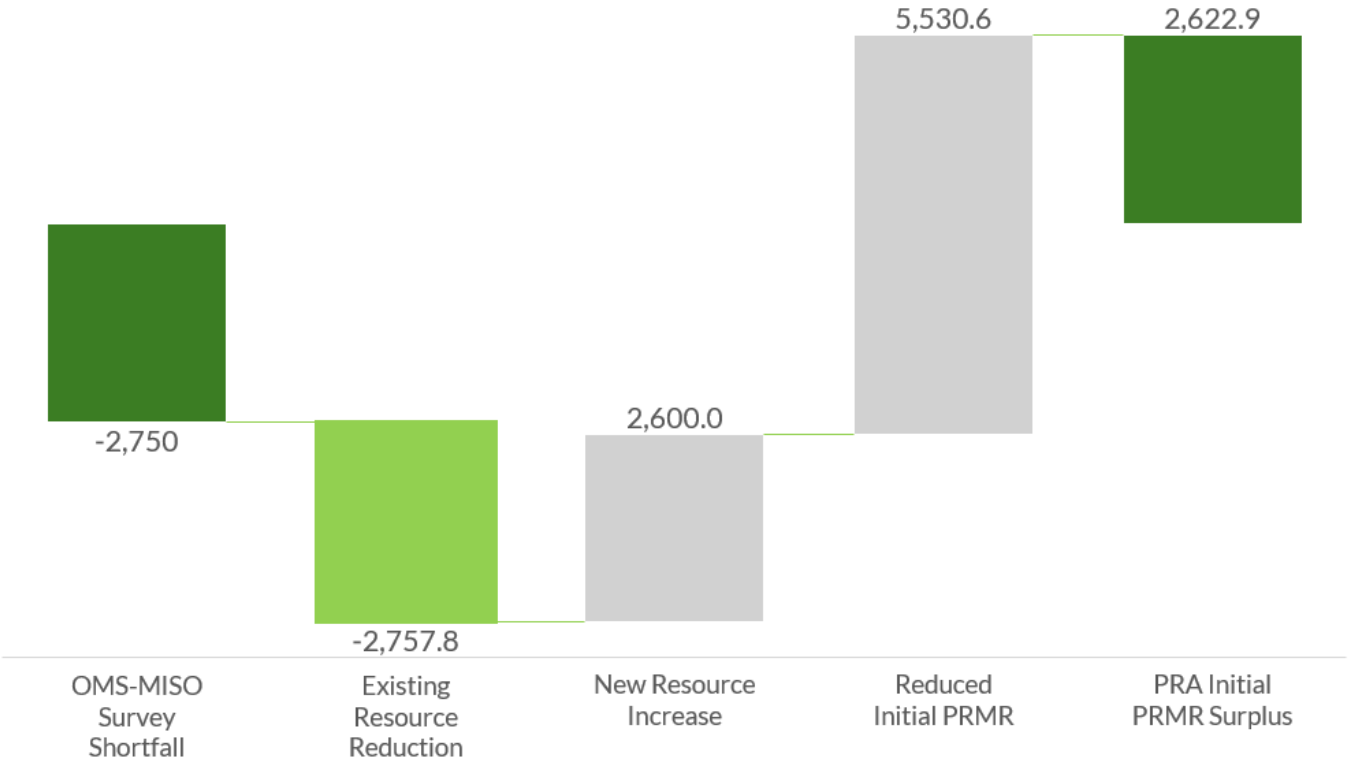
PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

The 2025 auction resulted in a surplus compared to the PRMR target, in contrast to the 2024 OMS-MISO Survey projection of a shortfall

Summer 2025 auction outcomes vs. 2024 OMS-MISO Survey projection for 2025

- Resource offers in the auction were comparable to "High Certainty" values projected in the OMS-MISO Survey
- Incremental accreditation reductions in the auction were offset by incremental increases in new resource additions
- Notably, initial PRMR was lower (5.5 GW) than projected in the OMS-MISO Survey

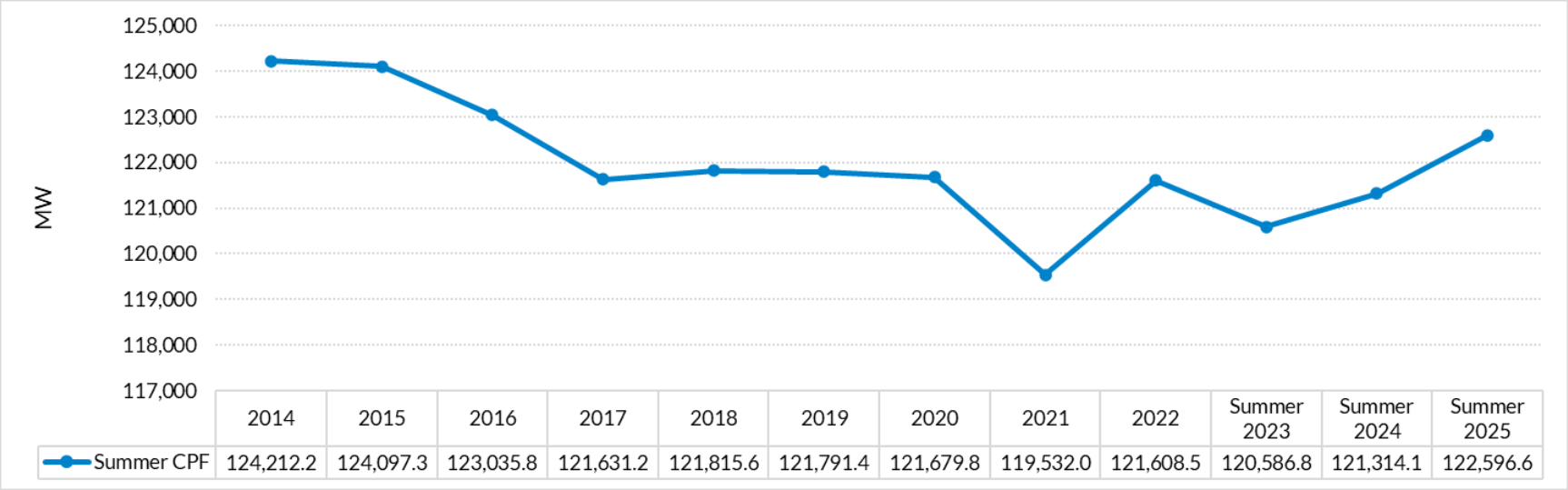
2024 OMS-MISO Survey Projection vs. 2025 PRA Actual PRMR Surplus (MW)



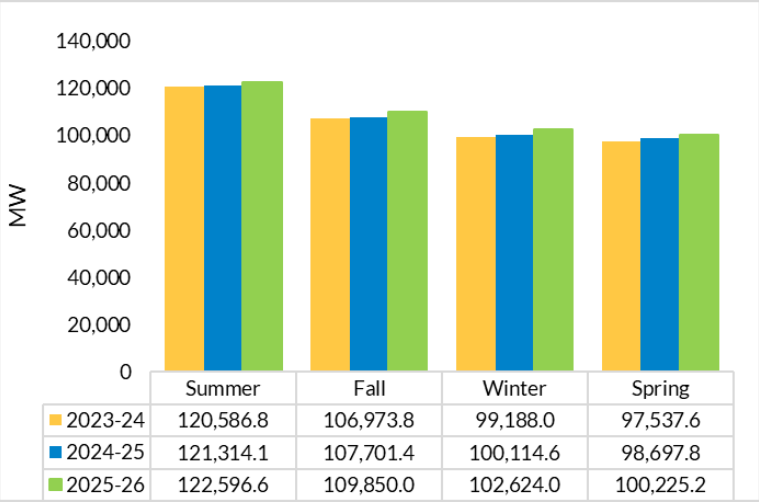
*PRA Shortfall/Surplus relative to Initial PRMR | PRMR: Planning Reserve Margin Requirement

Coincident Peak Forecast

Year over year the Summer CPF (+1.3 GW), PRM (-1.1%) and Final PRMR (+1.5 GW) are higher.



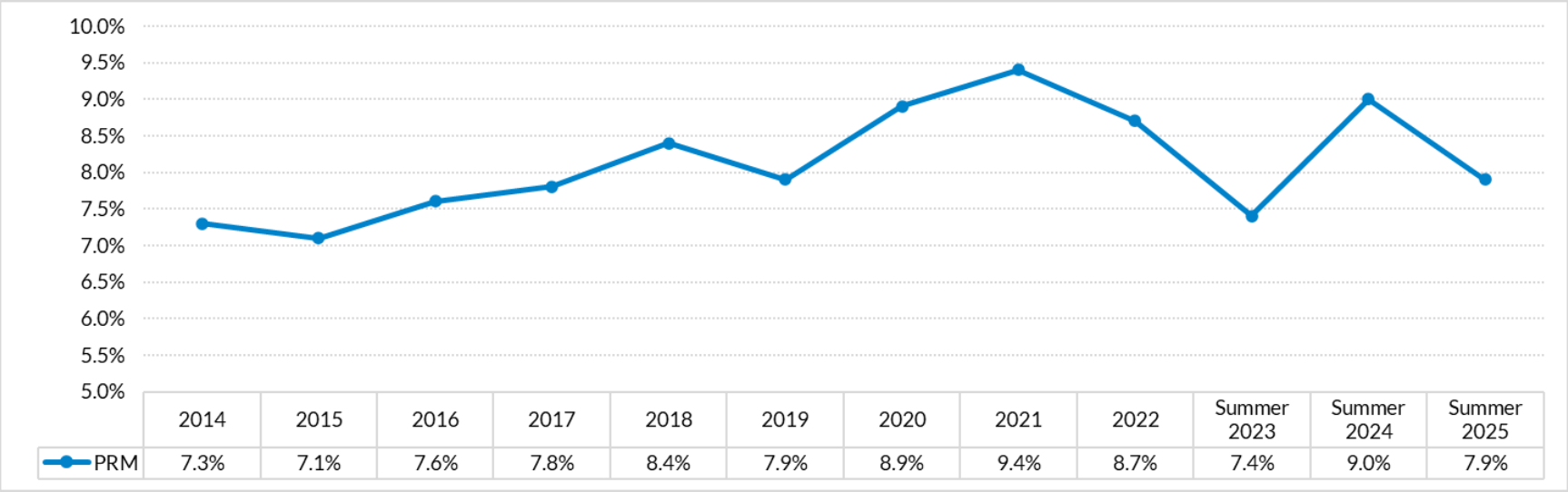
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
Summer CPF	124,212.2	124,097.3	123,035.8	121,631.2	121,815.6	121,791.4	121,679.8	119,532.0	121,608.5	120,586.8	121,314.1	122,596.6



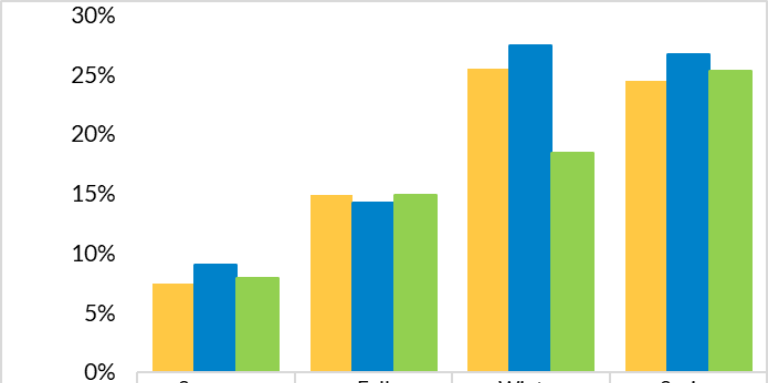
	Summer	Fall	Winter	Spring
2023-24	120,586.8	106,973.8	99,188.0	97,537.6
2024-25	121,314.1	107,701.4	100,114.6	98,697.8
2025-26	122,596.6	109,850.0	102,624.0	100,225.2

PRMR: Planning Reserve Margin Requirement

Planning Reserve Margin (%)

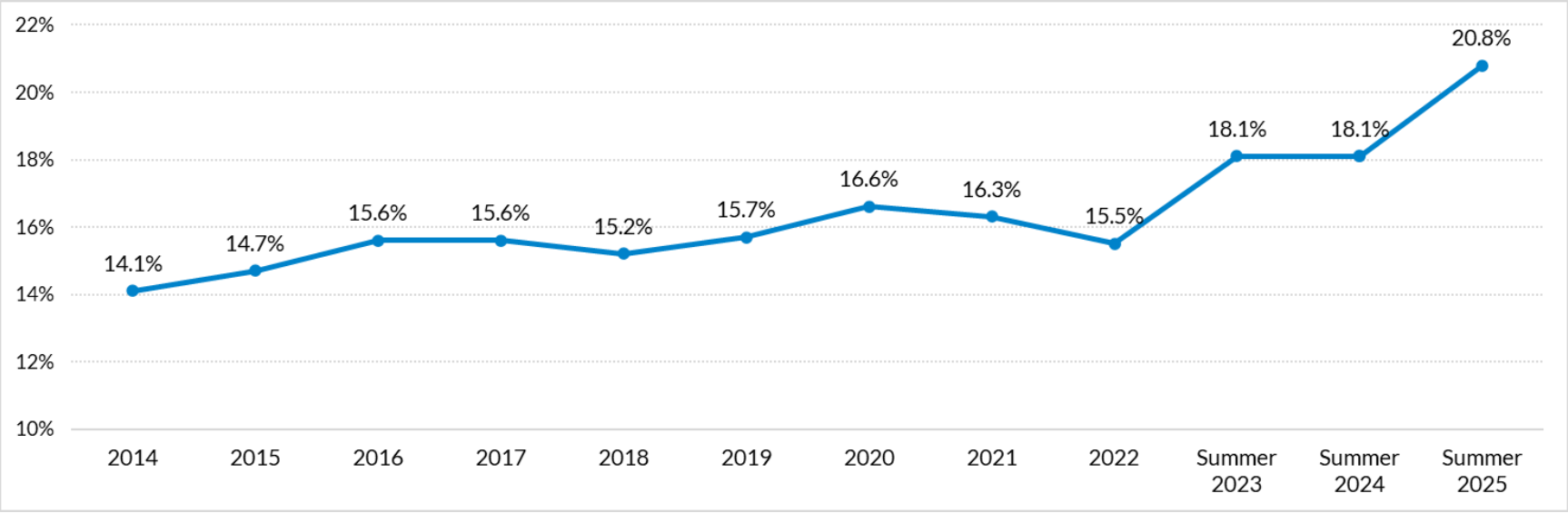


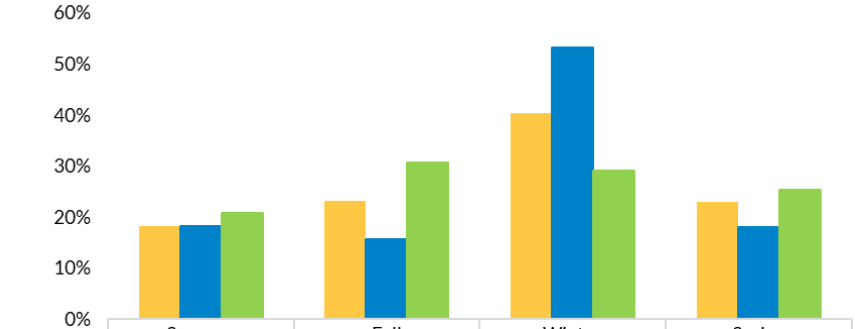
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%



	Summer	Fall	Winter	Spring
2023-24	7.4%	14.9%	25.5%	24.5%
2024-25	9.0%	14.2%	27.4%	26.7%
2025-26	7.9%	14.9%	18.4%	25.3%

Wind Effective Load Carrying Capacity (%)



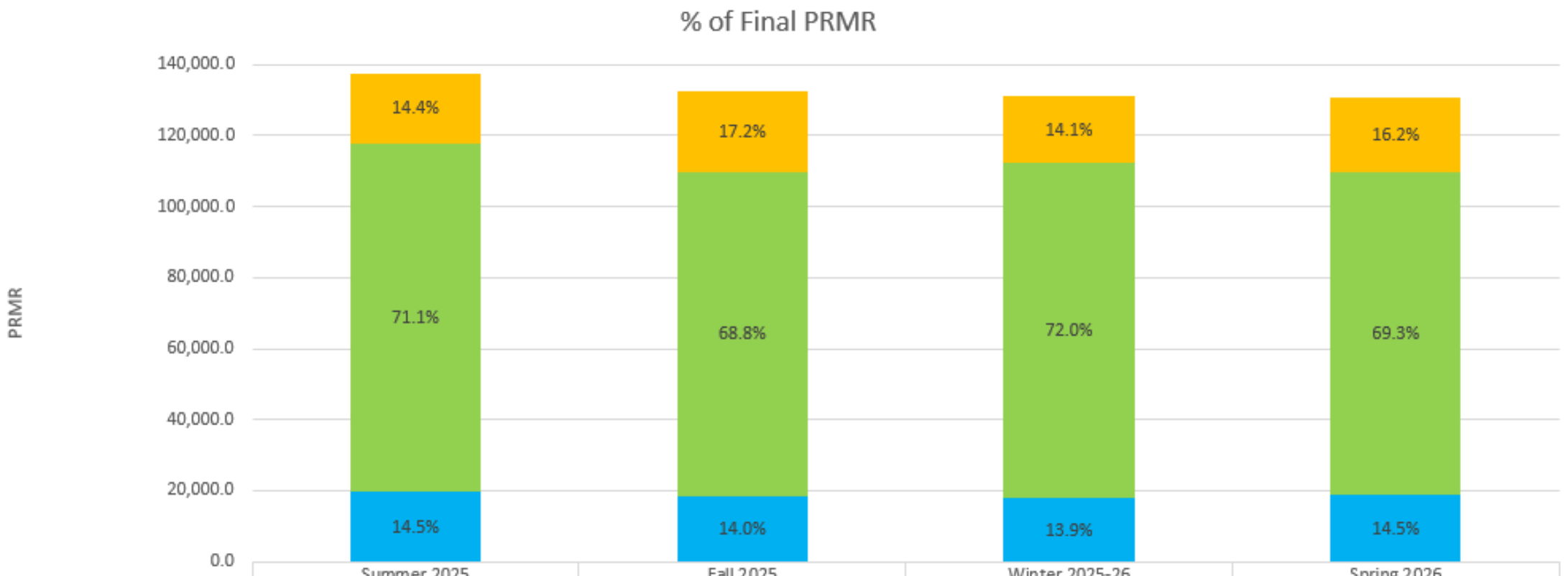


	Summer	Fall	Winter	Spring
2023-24	18.1%	23.1%	40.3%	23.0%
2024-25	18.1%	15.6%	53.1%	18.0%
2025-26	20.8%	30.7%	29.0%	25.3%

- No change to wind or solar accreditation methodology from previous years.
- Methodology applied on a seasonal basis.
- Wind ELCC and new solar capacity is established in the LOLE Study
- New solar class average
  - Summer, fall, spring 50%
  - Winter 5%

ELCC: Effective Load Carrying Capability LOLE: Loss of Load Expectation

2025/26 Seasonal Resource Adequacy Requirements are fulfilled similarly across all four seasons

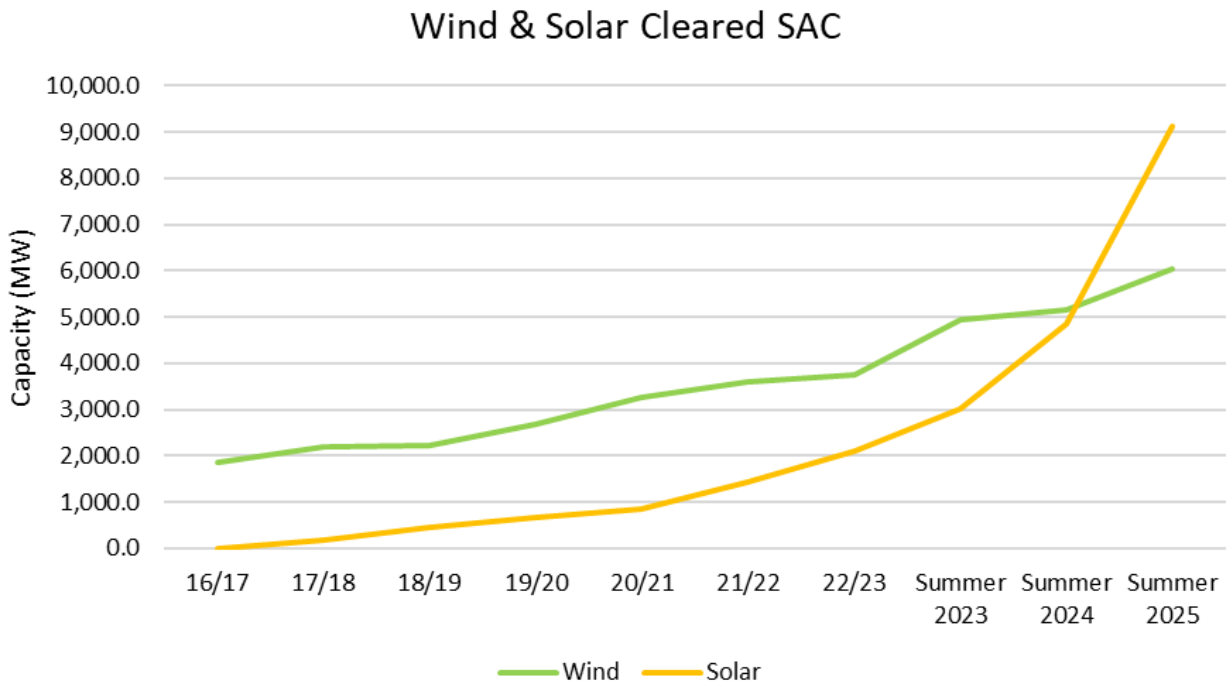


	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
FRAP	19,947.0	18,540.2	18,173.5	18,965.6

PRMR: Planning Reserve Margin Requirement

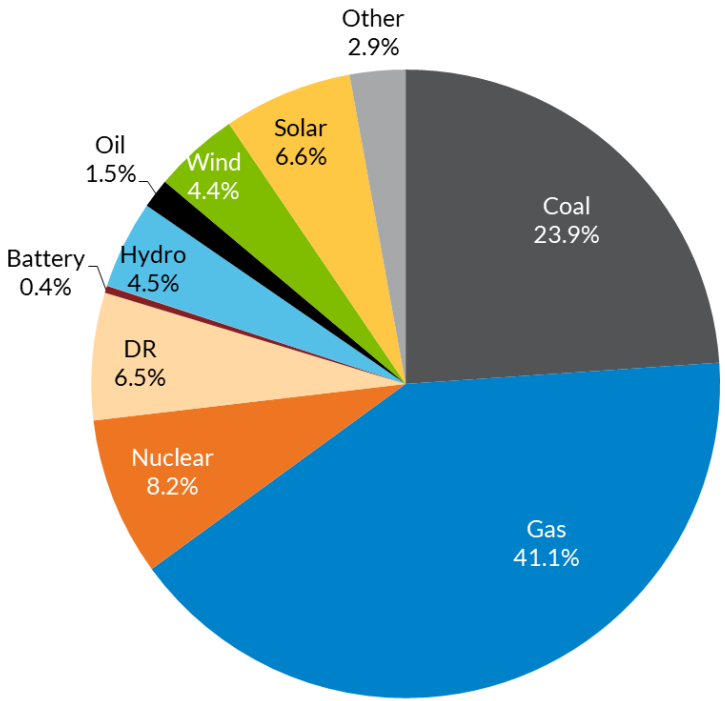
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

- 9.1 GW of solar cleared this year's auction, an increase of 88% from Planning Year 2024/25 (4.9 GW)
- 6 GW of wind cleared this year, an increase of 17% compared to last year (5.2 GW)



Winter final PRMR is 6.6 GW (4.8%) lower than the summer with fewer solar resources to meet final PRMR in the winter versus the summer

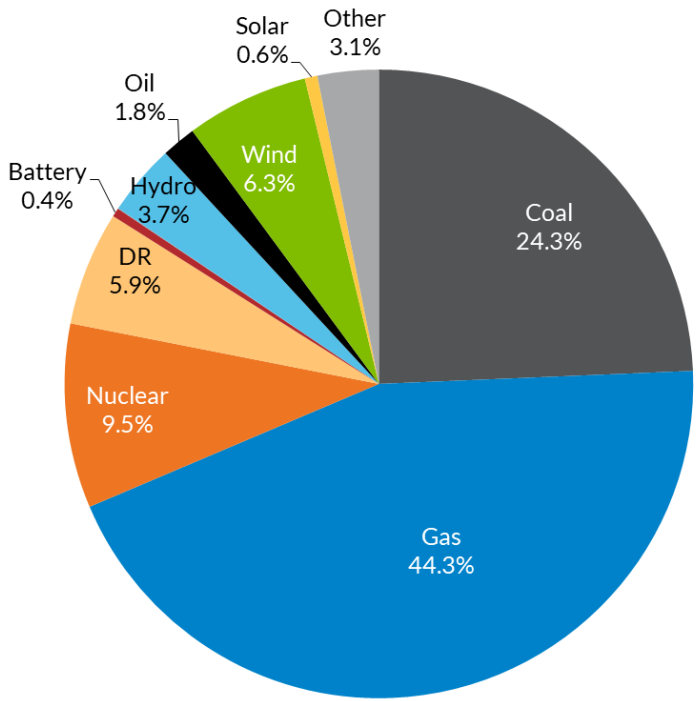
Summer 2025



MISO-wide

Cleared ZRC	Summer 2025	Winter 2025/26	Difference
Coal	32,909.6	31,887.2	1,022.4
Gas	56,470.0	57,990.5	-1,520.5
Nuclear	11,232.1	12,416.7	-1,184.6
DR	9,004.4	7,698.3	1,306.1
Battery	499.2	588.5	-89.3
EE	27.6	32.9	-5.3
Hydro	6,231.3	4,823.7	1,407.6
Oil	2,088.8	2,315.7	-226.9
Wind	6,039.1	8,282.9	-2,243.8
Solar	9,122.8	847.3	8,275.5
Misc	3,934.4	4,115.8	-181.4
PRMR	137,559.3	130,999.5	6,559.8

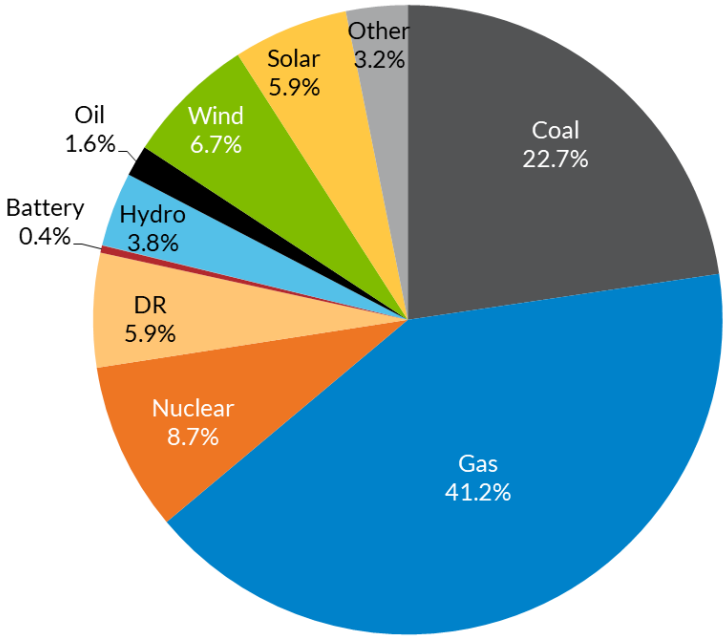
Winter 2025/26



PRMR: Planning Reserve Margin Requirement

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR

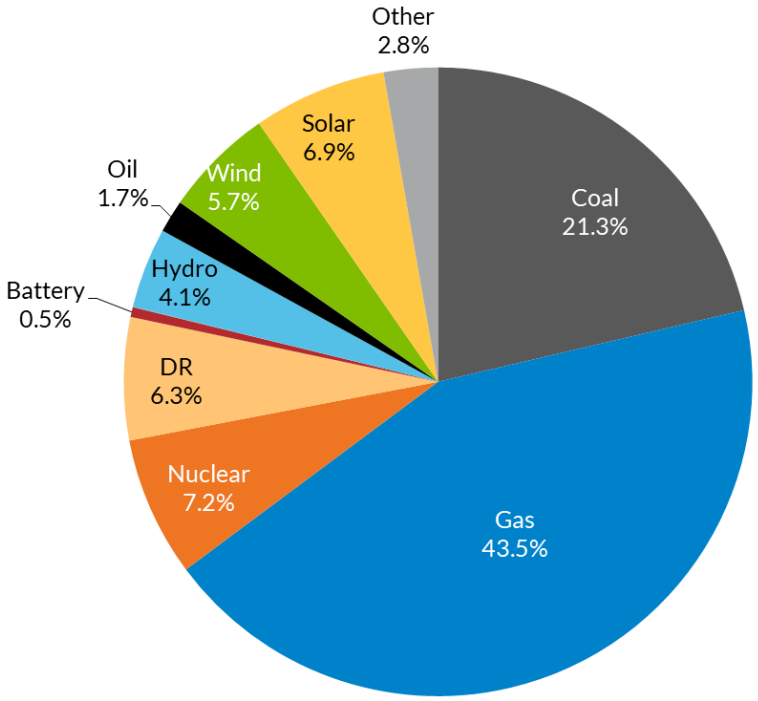
Fall 2025



MISO-Wide

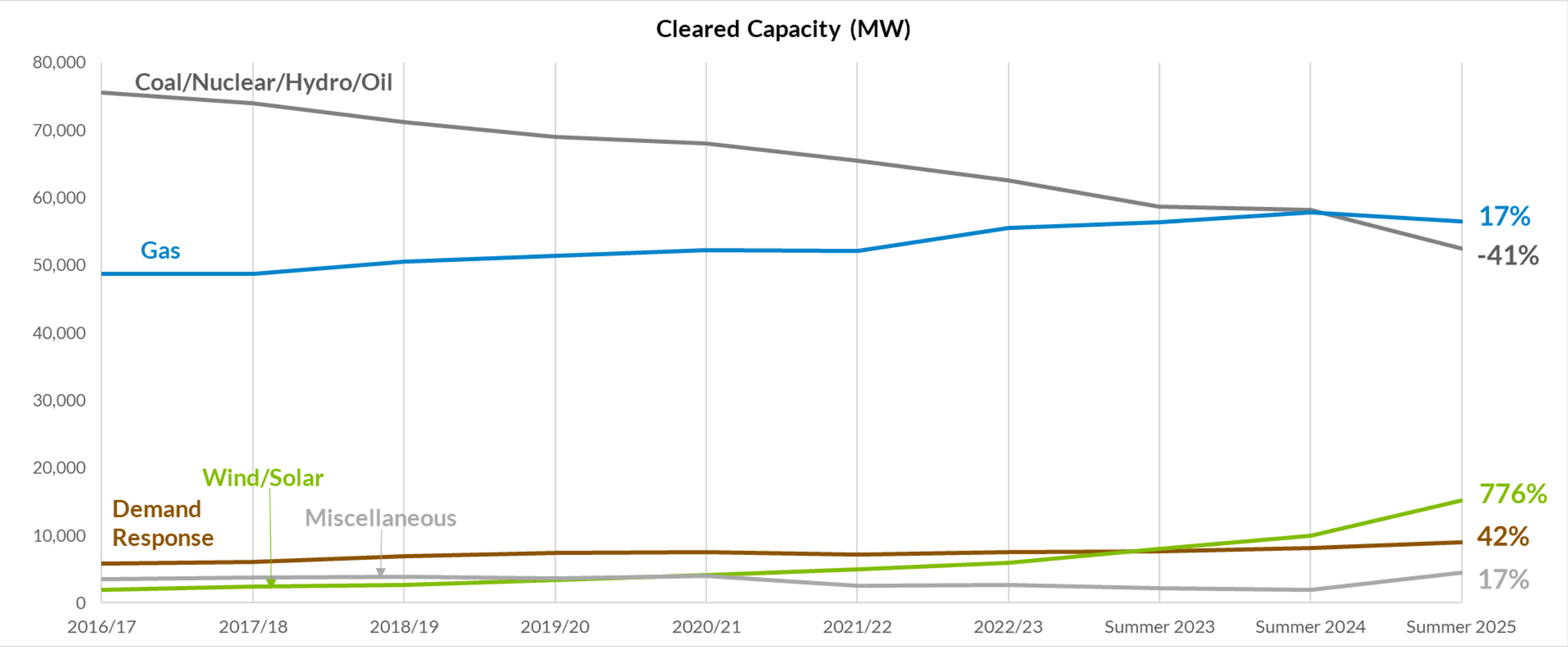
Cleared ZRC	Fall 2025	Spring 2026
Coal	30,038.9	27,886.8
Gas	54,636.4	56,820.7
Nuclear	11,482.1	9,405.4
DR	7,767.8	8,240.5
Battery	497.9	663.3
EE	28.1	30.5
Hydro	5,047.4	5,415.8
Oil	2,123.8	2,190.4
Wind	8,864.8	7,438.0
Solar	7,843.8	8,975.1
Misc	4,184.8	3,633.0
PRMR	132,515.8	130,699.5

Spring 2026

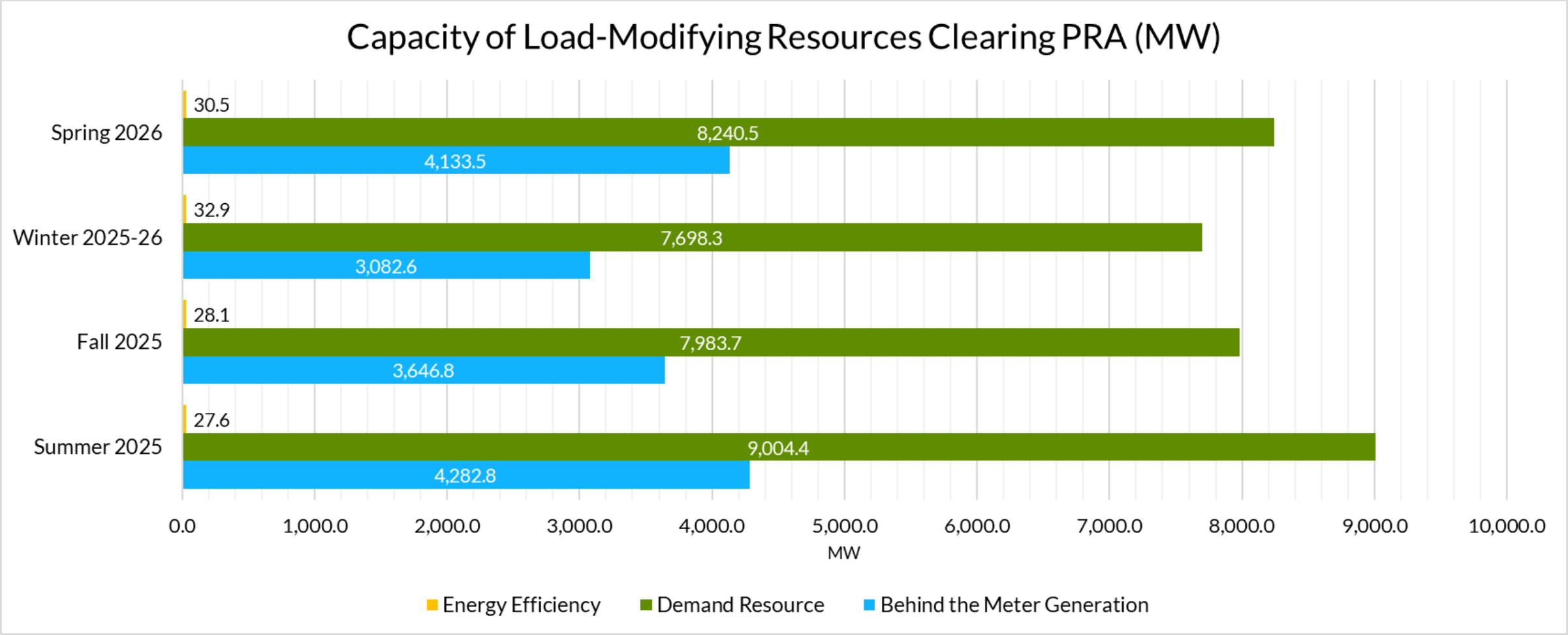


PRMR: Planning Reserve Margin Requirement

The planning resource mix shows the continuation of a multi-year trend towards less coal/nuclear/hydro/oil and increased gas and non-conventional resources



2025/26 Seasonally Cleared Load Modifying Resources Comparison



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Appendix D: June 7, 2029 Order in Case No. U-20165 –
Consumers Energy IRP Settlement Agreement

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.	)))))	Case No. U-20165

At the June 7, 2019 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Sally A. Talberg, Chairman
Hon. Norman J. Saari, Commissioner
Hon. Daniel C. Scripps, Commissioner

ORDER APPROVING SETTLEMENT AGREEMENT

I. Procedural History

On June 15, 2018, Consumers Energy Company (Consumers) filed an application, together with supporting testimony and exhibits, pursuant to 2016 PA 341 (Act 341); MCL 460.6t(3) and the Commission's December 20, 2017 and November 21, 2017 orders in Case Nos. U-15896 *et al.* and U-18418, requesting Commission approval of its integrated resource plan (IRP).[1]

A prehearing was held on July 16, 2018, before Administrative Law Judge Sharon L. Feldman (ALJ). The ALJ granted intervenor status to Michigan Environmental Council (MEC), the Sierra Club (SC), the Natural Resources Defense Council (NRDC), the Association of Businesses Advocating Tariff Equity (ABATE), Energy Michigan, Inc. (Energy Michigan), Michigan Energy

[1] MCL 460.6t is subsequently referred to as "Section 6t" throughout this order.

Innovation Business Council (MEIBC), Institute for Energy Innovation (IEI), the Independent Power Producers Coalition (IPPC), Solar Energy Industries Association, Inc. (SEIA), the Michigan Chemistry Council, the Michigan Electric Transmission Company, LLC (METC), Cypress Creek Renewables, LLC (Cypress Creek), the Residential Customer Group (RCG), the Great Lakes Renewable Energy Association (GLREA), the Michigan Department of the Attorney General (Attorney General), Midland Cogeneration Ventures, LP (MCV), the Environmental Law & Policy Center (ELPC), the Ecology Center, Vote Solar, the Union of Concerned Scientists, and a group of seven companies collectively referred to in this proceeding as the "Biomass Merchant Plants" or "BMPs" that includes: Cadillac Renewable Energy, LLC; Genesee Power Station, LP; Grayling Generating Station, LP; Hillman Power Company, LLC; TES Filer City Station, LP; Viking Energy of Lincoln, Inc.; and Viking Energy of McBain, Inc.[2] The Commission Staff (Staff) also participated in the proceeding.

On August 31, 2018, Invenergy Renewables LLC (Invenergy) filed a late petition for intervention and, during a September 18, 2018 hearing, the ALJ granted Invenergy intervenor status.

The ALJ issued a Proposal for Decision (PFD) on February 20, 2019. Consumers, the Staff, the Attorney General, MEC, NRDC, SC, GLREA, RCG, ABATE, SEIA, MCV, IPPC, Energy Michigan, ELPC, the Ecology Center, Vote Solar, and the Union of Concerned Scientists filed exceptions on March 4, 2019, and MEIBC, the Staff, SEIA, ELPC, the Ecology Center, Vote

[2] On April 5 and April 8, 2019, the Biomass Merchant Plants withdrew as parties to this proceeding.

Solar, the Union of Concerned Scientists, MEC, NRDC, SC, the Attorney General, Consumers, ABATE, RCG, and GLREA filed replies to exceptions on March 11, 2019.[3]

On March 23, 2019, Consumers entered into a settlement agreement with the following parties: the Staff, MEC, NRDC, SC, ABATE, Energy Michigan, IPPC, the Michigan Chemistry Council, METC, and the Attorney General. The settlement agreement recommends approval of Consumers' proposed course of action (PCA) with changes and covers issues such as: investments in conservation voltage reduction (CVR), demand response (DR), and energy waste reduction (EWR); retirement of certain coal-fired generation units; a financial compensation mechanism (FCM); avoided cost methodology under the Public Utility Regulatory Policies Act of 1978 (PURPA); and competitive bidding.

The following parties did not join the settlement, but offered a statement of non-objection: GLREA, RCG, MEIBC, IEI, ELPC, Invenergy, the Ecology Center, the Union of Concerned Scientists, and Vote Solar. MCV did not sign the settlement or indicate whether it would sign a statement of non-objection. On April 8, 2019, SEIA and Cypress Creek filed responses objecting to the settlement agreement.[4]

On March 25, 2019, Consumers and the Staff jointly filed a motion to extend the statutory deadlines found in Section 6t(7) of Act 341, MCL 460.6t(7). In its April 10 order, the Commission granted the joint motion and extended the deadlines for the Commission's 300-day

[3] Because ELPC, the Ecology Center, the Union of Concerned Scientists, and Vote Solar have submitted testimony and various filings in this docket jointly, this group of parties is often referred to throughout this order as "ELPC *et al*." for ease of reference. Similarly, in describing the joint positions and arguments of MEC, NRDC, and SC in this order, these parties are often referred to collectively as "MEC/NRDC/SC."

[4] The arguments that SEIA and Cypress Creek presented in their objections are discussed in detail in the Commission's April 10, 2019 order in this docket (April 10 order) and are also summarized in the "initial briefs" section of this order.

and 360-day orders. In addition, the Commission imposed deadlines by which parties may submit direct and rebuttal testimony regarding the requested approval of the contested settlement agreement. The Commission also scheduled an evidentiary hearing on the contested settlement agreement and established deadlines by which parties may file initial and reply briefs. Because the Commission has decided to read the record for purposes of evaluating the settlement agreement, a summary of the evidentiary record related to the settlement agreement follows.

II. Evidentiary Record

The evidentiary record in this contested settlement proceeding consists of 173 pages of transcript and 2 exhibits.[5]

A. Direct Testimony

SEIA, ABATE, ELPC *et al*., and the Staff timely filed direct testimony on April 19, 2019.

1. Staff

In the Staff's direct testimony, Paul Proudfoot, the Director of the Energy Resources Division, asserts that Consumers' PCA, as modified by the settlement agreement, meets the statutory requirements of Act 341. 10 Tr 3021. For this reason, Mr. Proudfoot urges the Commission to approve the contested settlement agreement in its entirety and without recommending changes under Section 6t(7). Mr. Proudfoot also states that the contested settlement agreement meets the requirements of Mich Admin Code, R 762.10431 (Rule 431). *Id*.

[5] The Commission notes that, in the original IRP proceeding that resulted in a PFD, the evidentiary record included 2929 transcript pages in nine volumes. It included the testimony of 62 witnesses and 363 exhibits, with certain transcript pages and exhibits designated as confidential. *See*, PFD, p. 4. The Commission references this evidence throughout this order.

2. Solar Energy Industries Association, Inc.

SEIA's direct testimony consists of the testimony of Kevin Lucas, SEIA's Director of Rate Design. Mr. Lucas testifies that, in the contested settlement agreement, Consumers fails to address the interconnection queue of projects at different stages of development under the PURPA regime from Case No. U-18090. 10 Tr 2942. Mr. Lucas explains that, although Consumers is "attempting to ignore and deflect" its obligations to qualifying facilities (QFs) under PURPA, the Commission has directed Consumers to move forward with contracting with QF projects in its queue. *Id*. Mr. Lucas also states that Consumers is delaying the interconnection of new QFs beyond the time periods prescribed in the Commission's generator interconnection rules by requesting a waiver of timelines in those rules. Mr. Lucas explains that Consumers has failed to interconnect a single new QF of late despite the fact that some QF projects have been in the utility's interconnection queue since 2017. 10 Tr 2944. Mr. Lucas asserts that the Commission's approval of Consumers' PCA, while the fate of the existing PURPA queue remains unresolved, has the potential to "result in the Company overprocuring capacity in the near term and incurring unnecessary costs to be borne by its customers" which Mr. Lucas views as contrary to the public interest. *Id*. Mr. Lucas states that the focus should not be on whether QFs can participate in future competitive solicitations, but on Consumers' obligation, under federal law, state law, and the Commission's direction, to contract with QFs in the queue. *Id*., p. 2945. Mr. Lucas recommends that the Commission reject the proposed settlement agreement because of the unnecessary additional costs to ratepayers that will result from the overprocurement of capacity if Consumers is required to contract with QFs in its interconnection queue. *Id*. Alternatively, SEIA has developed a proposal that, if included in the proposed settlement agreement, would address the QFs in

Consumers' interconnection queue and "would result in a fair and reasonable resolution to the proceeding that is in the public interest." *Id*.

In addition to Mr. Lucas' contention that the Commission should reject the settlement agreement because it fails to acknowledge the rights of QFs in the utility's interconnection queue, Mr. Lucas asserts that the Commission should also reject it because the stipulation in the settlement agreement that Consumers has no PURPA capacity need is inconsistent with the evidentiary record in this case. That stipulation fails to recognize that the projected need in Consumers' original PCA included 157 zonal resource credits (ZRCs) from the T.E.S. Filer City power purchase agreement (PPA) and 50 ZRCs of capacity related to the 100 MW of self-build solar from the utility's renewable energy plan (REP), both of which will no longer be available. Further, given the ALJ's finding that the 56 ZRCs associated with CVR were unreasonable and should not be approved, Mr. Lucas points out that Consumers has a PURPA capacity need rather than a capacity surplus. 10 Tr 2946. Although Consumers updated its capacity position in its rebuttal testimony to reflect the loss of 157 ZRCs from the T.E.S. Filer City PPA, Mr. Lucas explains that Consumers continues to assume that 50 ZRCs of self-build solar would have been built for its REP, and this 100 MW/50 ZRCs of solar remains in the utility's PCA. *Id*. Mr. Lucas argues that, if the Commission approves the proposed settlement agreement, Consumers' customers will be forced to substantially overpay for solar capacity and that this is contrary to the public interest. Mr. Lucas testifies that the proposed 100 MW of self-build solar is overpriced and should not be approved. Mr. Lucas further asserts that Consumers' capacity shortfall position could be exacerbated by: (1) the utility's reliance in its PCA on massive quantities of EWR and DR that may not materialize, and (2) the projected increase in transportation energy usage starting in the early 2020s due to an increasing number of electric vehicles in Michigan. Accordingly, Mr.

Lucas asks the Commission to reject the settlement agreement and determine that Consumers has a capacity shortfall of at least 80 ZRCs. *Id*., p. 2948.

Mr. Lucas likewise argues that the Commission should reject the FCM proposal set forth in the proposed settlement agreement because it is contrary to the public interest. Mr. Lucas agrees with the ALJ's reasoning in the PFD, which contains a detailed critique of the FCM. Mr. Lucas explains that there is also no policy justification to extend the FCM to PURPA contracts because, "[u]nlike its choice on how to meet its future load obligations through either PPAs or self-build projects, Consumers is required to purchase QF output." *Id*., p. 2954. Mr. Lucas continues that giving Consumers an incentive to do something the law already obligates the utility to do accomplishes nothing other than increasing costs to Consumers' customers, and is contrary to PURPA. *Id*.

Mr. Lucas also states that the proposed settlement agreement needlessly increases costs for Consumers' customers because it proposes to split future capacity procured through competitive solicitations 50/50 between third-party PPAs and company-owned projects. *Id*. Mr. Lucas explains that company-owned projects are going to be more expensive than third-party PPAs. Mr. Lucas discusses a Consumers' exhibit that shows the levelized cost of energy (LCOE) of Consumers-owned solar projects. Compared to the avoided costs in U-18090 or to the limits of the FCM in the settlement agreement's Attachment B, Consumers' projections exceed the avoided costs in U-18090 by 37% and exceed the value of Attachment B by 44%. Mr. Lucas contends that, even with up-to-date estimates on capital costs, the reduction to Consumers' LCOE would not be enough to reduce its prices by the 37-44% needed to be on par with third-party PPAs. *Id*., p. 2957. In addition, Mr. Lucas points out that Consumers will earn a return on the asset, on top of developer profit already included in the sales price. *Id*., p. 2956. And, Consumers will fully

depreciate the project over 25 years despite the fact that the asset will retain its substantial value at the end of that 25-year period. Finally, Mr. Lucas explains that regulatory accounting requirements prevent Consumers from realizing federal investment tax credit savings the same way that third-party developers do. Therefore, company-owned systems are projected to be substantially more expensive for Consumers' customers than third-party PPAs. Therefore, Mr. Lucas recommends that the Commission require Consumers to eliminate the preference for company-owned projects or to "shift competitive procurement much more heavily towards third-party PPAs and away from Company-owned projects." *Id.*, p. 2959.

In addition to all of these issues, Mr. Lucas states that the agreed-upon competitive solicitation process set forth in the settlement agreement still gives Consumers too much control over the solicitation, because Consumers gets to decide the evaluation process and the selection criteria. *Id.*, p. 2960. Although Consumers will review the process with the Staff, the utility is not required to incorporate feedback. Mr. Lucas notes that the ALJ did not trust Consumers and instead found its process biased towards utility-owned assets and further determined that the proposed process did not create a level playing field for independent developers. *Id.* Mr. Lucas recommends that the Commission adopt SEIA's detailed list of procedures in its objections and in Attachment A to its initial brief as the starting point for the first competitive solicitation. *Id.*, p. 2961.

Next, Mr. Lucas discusses the changes that the proposed settlement agreement makes to PURPA. Because the change in the term of the Standard Offer contract from 20 years to 10 years does not present any information regarding whether this shorter term will allow developers a reasonable opportunity to attract capital, Mr. Lucas asserts that the Commission should remain consistent with its current rulings on this issue favoring a 20-year contract term. *Id.*, p. 2962. Mr. Lucas maintains that all of the contract term options the settlement agreement offers QFs are

flawed. With respect to the 15-year contract option that is based on locational marginal price (LMP) with a Midcontinent Independent System Operator, Inc. (MISO) planning resource auction (PRA) price that resets each year, Mr. Lucas argues it does not provide any long-term price assurance and results in the developer bearing all the risk. In addition, he asserts that this option makes it impossible for QFs to secure required financing. *Id*. Mr. Lucas asserts that a second option that offers QFs a contract term of 10 years of known pricing will be even more inaccurate than the first option, because this option freezes forecasted prices at year 5 prices in years 6 through 10. *Id*., p. 2963. Regarding the capacity outlook period, Mr. Lucas agrees that it would be moot as long as Consumers' PCA is followed. *Id*., p. 2964. However, in the event that the PCA is not followed or if the Commission rejects the settlement agreement or Consumers' IRP, Mr. Lucas proposes that the Commission remain consistent with its past orders and retain the 10-year capacity horizon outlook. *Id*.

According to Mr. Lucas, another reason the proposed settlement agreement should be rejected is because the public interest "was not adequately represented" and the settlement agreement will cause SEIA's members material harm. Mr. Lucas asserts that, although 11 parties signed the settlement agreement, 19 did not. He believes that a settlement agreement that lacks a solar QF developer as a signatory cannot represent the public interest given that nearly 3,500 MW of solar QFs are currently in Consumers' interconnection queue. *Id*., p. 2966. Mr. Lucas continues that the cost savings that could be realized by leveraging QF projects instead of company-owned solar support this conclusion.

Mr. Lucas also identifies the following harm to SEIA's members if the Commission approves the proposed settlement agreement. He explains that "SEIA reached out to QF developers who collectively represented more than 90% of the QF MW in [Consumers'] interconnection queue."

According to Mr. Lucas, developers spent "millions of dollars" for predevelopment work on "more than 3,000 MW" of solar projects. *Id*., p. 2967. Mr. Lucas continues that SEIA's proposal described in its objections to the settlement agreement, to resolve the issue of existing QF projects in Consumers' interconnection queue, presents a fair and reasonable resolution of the matter. Mr. Lucas explains that the proposal would interconnect, under current Case No. U-18090 rules and rates, 800 MW of QF projects (in addition to the 150 MW the Commission already ordered in that case) from the existing queue that have met threshold eligibility requirements. *Id*., pp. 2967-2968. Mr. Lucas emphasizes that, if the Commission approves the contested settlement agreement without resolving the interconnection issue, the approved settlement agreement does not supersede the legal rights of projects in the queue. Therefore, project developers are likely to file individual complaints against Consumers regarding the utility's failure to interconnect their QF projects. *Id*., p. 2969. Mr. Lucas asserts that this protracted litigation will use up limited Commission and Staff time and resources and will hinder Consumers' ability to transition to its new capacity procurement methodology. *Id*. He also explains that this will negatively affect investment in Michigan. Therefore, Mr. Lucas recommends that the Commission condition its approval of the proposed settlement agreement on inclusion of SEIA's QF proposal.

3. <u>Association of Businesses Advocating Tariff Equity</u>

ABATE presented the testimony of Jeffry Pollock, an energy advisor and President of J. Pollock, Inc., who testified that ABATE supports the settlement agreement because it resolves ABATE's initial concerns over Consumers' proposed PCA, is supported by parties that represent Michigan ratepayers, and was the result of substantial negotiations between active participants reflecting numerous compromises from their litigated positions. 10 Tr 3000. According to Mr. Pollock, a primary concern of ABATE's in the IRP proceeding was Consumers' recovery of the

unamortized costs of the early retirement of Units 1 and 2 of the D.E. Karn coal-fired generation plant, which the settlement agreement satisfactorily resolves by allowing Consumers to securitize the remaining net book value of the two units.[6] Mr. Pollock explains that securitization both minimizes the cost of financing the recovery on the remaining investment in the units and prevents the utility from earning a return on an investment that is no longer used and useful.

ABATE also supports the proposed settlement agreement because it authorizes competitive solicitation for all new resources, including capacity obtained from PPAs and capacity that Consumers will include in rate base. Mr. Pollock further explains that the results of the competitive solicitations will define the PURPA avoided cost for any PURPA-based PPAs. Mr. Pollock asserts that adoption of competitive solicitation ensures that all new capacity additions are priced competitively with current market conditions. Mr. Pollock expounds on this issue by explaining that, although Consumers' full avoided cost ranges from $95-$110 per megawatt-hour (MWh), the current LCOE for a 20-year QF solar PPA is only $50.86 per MWh. He emphasizes that ratepayers cannot afford to pay the higher avoided cost for new capacity under long-term PURPA PPAs when the same resources can be acquired competitively for half the cost. *Id.*, p. 3002.

The settlement agreement also addresses ABATE's concern about Consumers' heavy reliance on DR as a resource. Although Consumers' PCA will result in DR resources supplying the utility's entire reserve margin, Mr. Pollock notes that the settlement agreement requires Consumers "to conduct additional studies to determine best practices on the amount of reserves that could be provided by DR and to assess the potential changes in either the frequency or

[6] D.E. Karn Units 1 and 2 refer to two coal-fired generation units currently owned and operated by Consumers. These coal-fired generation units are also referred to as "Karn 1 and 2" interchangeably throughout this order.

duration of curtailments and the role of DR in meeting peak demand." *Id*., p. 3001. Mr. Pollock next discusses SEIA's concern that allowing Consumers to provide up to 50% of new capacity additions through company-owned projects will be more expensive for the utility's customers. He disagrees with SEIA on this point because Consumers will acquire this capacity through "build-own-transfer" agreements that permit the project developer to fully utilize any applicable investment tax credits before the project is transferred to Consumers. Mr. Pollock explains that this allows owned projects to be included in rate base "at a much lower value than if Consumers had self-built the new capacity." *Id*., p. 3002.

Further, despite ABATE's initial opposition to an FCM, Mr. Pollock explains that credit rating agencies do consider fixed obligations under PPAs when evaluating a utility's financial strength and that the inclusion of an FCM ensures the additional cost of any third-party PPAs is reflected in the competitive solicitation process. Further, Mr. Pollock points out that the settlement agreement provides the Commission can consider the FCM in determining Consumers' overall cost of capital in future rate cases. Mr. Pollock notes that this provision ensures future rates are more just and reasonable. *Id*., p. 3003.

Last, Mr. Pollock explains that the settlement agreement is in the public interest because its signatories include parties that represent ratepayers, its competitive solicitation process ensures electricity rates will remain affordable, and its terms were negotiated at arm's length with diligence and with significant give-and-take among the parties.

4. Environmental Law & Policy Center *et al*.

ELPC *et al*. presented the direct testimony of James P. Gignac, Lead Midwest Energy Analyst employed by the Union of Concerned Scientists, who identified several improvements to Consumers' filed IRP that are presented in the proposed settlement agreement. 10 Tr 3008. Mr.

Gignac states that the proposed settlement agreement is in the public interest. However, Mr. Gignac also agrees with SEIA that the QF projects in Consumers' interconnection queue need to be addressed in a timely manner and notes many benefits that can be achieved in reaching a timely resolution on this issue. *Id*., p. 3011. Mr. Gignac explains that addressing the existing PURPA queue would enable ELPC *et al*. to become signatories to the settlement agreement.

B. Rebuttal Testimony

The Staff, SEIA, and Consumers each filed rebuttal testimony regarding Commission approval of the contested settlement agreement.

1. Staff

Mr. Proudfoot testified on behalf of the Staff that the Staff supports the proposed FCM in the settlement agreement because it falls within the acceptable range that the Staff presented when it calculated alternative FCM methodologies in the underlying IRP proceeding in this docket. 10 Tr 3025. Mr. Proudfoot further explains that the reasonable FCM proposed in the settlement agreement "will help to facilitate these potential cost reductions for future projects by reducing risk to the Company and making it more impartial to decisions between Company-owned assets and PPAs." *Id*., p. 3026.

In addition, Mr. Proudfoot maintains that allowing Consumers to own 50% of its future capacity needs is reasonable and can lead to cost reductions rather than increased customer costs as Mr. Lucas asserts. *Id*. Mr. Proudfoot explains that state law requires electric providers to enter into PPAs for at least 50% of their required renewable assets needed to meet renewable standards and that this competition led to impressive cost reductions for wind assets. Mr. Proudfoot notes that, on a weighted average basis, company-owned wind assets are less costly than PPA wind

assets, and further explains that Consumers "is likely to see very similar results for solar assets." *Id*., p. 3027.

Mr. Proudfoot disagrees with SEIA that the changes to PURPA set forth in the settlement agreement are not supported by the record. Rather, according to Mr. Proudfoot, the settlement agreement "does not waver" from Consumers' initial proposal in this case, which the Staff supports. *Id*. Further, Mr. Proudfoot explains that the Staff disagrees with SEIA that this IRP case should resolve Consumers' interconnection queue because he believes that, to resolve it, the Commission must make determinations "outside of the IRP process with more of a focused review." *Id*., p. 3028. Mr. Proudfoot recommends that the Commission define a legally enforceable obligation (LEO) and explain how to manage queue projects in a separate proceeding. *Id*.

Mr. Proudfoot disagrees with SEIA's contention that PURPA-related decisions determined in this agreement could bind a future Commission. According to Mr. Proudfoot, the settlement agreement clearly states that, although Consumers' PCA is the most reasonable and prudent means of meeting Consumers' capacity and energy needs right now, the Commission will reevaluate Consumers' PCA in future IRP proceedings. *Id*. Mr. Proudfoot also disagrees with SEIA's assessment that its members are harmed by the PURPA changes proposed in the settlement agreement regarding PURPA contract length and modified avoided cost methodology. According to Mr. Proudfoot, the harm SEIA mentions is both "unknown and highly speculative." *Id*., p. 3029. He further clarifies that there is no guarantee that any SEIA members would qualify for PURPA contracts because the Commission has not established an LEO determination methodology, and because neither the Commission nor the Federal Energy Regulatory Commission (FERC) has made any LEO determinations on a case-by-case basis. *Id*. Moreover,

Mr. Proudfoot points out that the Commission-designated stakeholder process to establish rules regarding an LEO is still ongoing. Mr. Proudfoot also identifies an additional unknown variable, i.e., whether "the distribution grid is robust enough to support electric connections without extensive and costly upgrades." Without more information regarding whether interconnection queue projects would qualify for an LEO and be economical from an interconnection cost perspective, Mr. Proudfoot explains that the Staff believes "the same speculative risk of harm exists" for SEIA members under this settlement agreement as for Michigan ratepayers who would have to pay higher avoided costs rates if Consumers were to enter into PURPA contracts with SEIA members. *Id*., p. 3030. Mr. Proudfoot further clarifies that other PURPA projects are available besides those in Consumers' interconnection queue. *Id*. Finally, Mr. Proudfoot asserts that all parties were given a reasonable opportunity to present evidence and arguments in opposition to the settlement agreement, that the proposed settlement agreement is representative of most if not all of Michigan's sectors concerned with the future of energy-related issues, and that the settlement agreement is supported by substantial evidence on the record as a whole. *Id*., pp. 3030-3032.

2. Consumers Energy Company

Consumers' rebuttal testimony consists of testimony from witnesses Richard T. Blumenstock, Consumers' Executive Director of Electric Supply; Srikanth Maddipati, Consumers' Treasurer and Vice President of Investor Relations; Michael A. Torrey, Consumers' Vice President, Rates and Regulation; and Keith G. Troyer, Consumers' Manager of Supply Contracts in the Transactions and Wholesale Settlements, Electric Contract Strategy Section of the Electric Supply Department.

Mr. Blumenstock provides an overview of the settlement agreement. 10 Tr 3037-3039. He also lists the parties that signed the agreement, those who signed a statement of non-objection,

those who remained silent, and those who opposed it. Mr. Blumenstock agrees with Staff witness Paul Proudfoot that the settlement agreement meets the statutory requirements of MCL 460.6t. Mr. Blumenstock provides a detailed explanation of why the settlement agreement satisfies the planning objectives that the Commission set forth pursuant to Section 6t(8), how it ensures resource adequacy and capacity that is sufficient to serve anticipated peak electric load plus the applicable planning resource margin requirement and local clearing requirement, and how it ensures compliance with applicable state and federal environmental regulations. *Id*., pp. 3041-3042. Mr. Blumenstock explains that the settlement agreement ensures competitive pricing by maintaining a strategy of modular deployment of new generation sources, allowing for phase-in of associated costs, and limiting rate impact on a year-to-year basis. *Id*., p. 3043. In addition, because the PCA avoids large capital investments tied up in one project and provides for competitive bidding of all new supply-side generation, Mr. Blumenstock asserts that the settlement agreement limits the costs to the ratepayer. *Id*. Mr. Blumenstock lauds the company's PCA as providing the requisite flexibility to adjust to changes in cost, electric demand, or the business environment. He explains that the features of a modular approach insulate the company and its ratepayers from commodity price risks and protects against high customer rates. *Id*., p. 3044. Mr. Blumenstock also describes how the settlement agreement ensures diversity of generation supply. *Id*.

Regarding the proposed levels of peak load reduction which include DR, CVR and EWR, Mr. Blumenstock states these levels are reasonable and cost-effective. He also lists other benefits of the settlement agreement, including the competitive bid procurement process, the significant amount of collaboration envisioned between stakeholders on future competitive bidding guidelines, a new capacity procurement process in each annual solicitation that is competitively

bid and that consists of 50% new capacity from PPAs and 50% of new capacity owned by Consumers as acquired through a competitive bidding process, and an FCM on PPA payments. Mr. Blumenstock views a provision in the settlement agreement that requires Consumers to file its next IRP by June 2021 to be a positive benefit that allows stakeholders an opportunity to more closely track and assess Consumers' implementation of the PCA to ensure that it remains reasonable and prudent. Further, Mr. Blumenstock views the testimony submitted in this case to support approval of Consumers' PCA and the settlement agreement. *Id*., p. 3047.

Mr. Blumenstock next addresses SEIA's argument that the settlement agreement fails to acknowledge Consumers' obligation to contract with PURPA QFs. Mr. Blumenstock counters that the settlement agreement does not "completely ignore" PURPA rights or obligations. *Id*., p. 3048. Rather, Mr. Blumenstock alludes to paragraph 12 of the agreement as providing that the agreement is not intended to affect or waive the PURPA rights or positions of any party that existed before the Commission's approval of the settlement agreement. *Id*. According to Mr. Blumenstock, this provision means that the agreement will not impair the ability of Consumers, ratepayers, QFs, or any other stakeholders to raise PURPA issues related to any QFs currently seeking rates set forth in Case No. U-18090 in other proceedings. *Id*. Further, Mr. Blumenstock agrees with Mr. Troyer that, although the settlement agreement does not address issues related to the QFs in the company's interconnection queue and the rates these projects could receive, those issues are complex and not in the record in this case and should not be decided here. *Id*. He asserts that resolution of those issues differs greatly for each developer in the interconnection queue. *Id*. Mr. Blumenstock also notes that SEIA's proposal to resolve issues related to the QFs in Consumers' interconnection queue was first presented in SEIA's objections to the settlement agreement, and that this proposal does not provide sufficient grounds for rejecting that agreement.

Id. Mr. Blumenstock claims that the settlement agreement does not impair the PURPA rights of QFs in Consumers' interconnection queue. *Id*. He believes that PURPA QFs have the ability to advocate for their perceived rights under PURPA outside of this IRP case as Cypress Creek has done.

Regarding SEIA's assertion that Consumers has a capacity need, Mr. Blumenstock disagrees. *Id*., p. 3050. According to Mr. Blumenstock, Mr. Lucas' settlement direct testimony does not establish that the capacity sources cited in that testimony create a capacity need of 80 ZRCs. *Id*., p. 3051. Mr. Blumenstock explains that removal of the capacity provided by the T.E.S. Filer City plant will not result in a capacity shortfall until 2031 and 2032 and, by then, it would be a small shortfall that may never materialize. *Id.* Mr. Blumenstock further explains that it is premature for SEIA to assume that the 100 MW of self-build solar capacity results in a capacity need because the Commission has not denied it. *Id*., p. 3052. Moving on to the 56 ZRCs associated with the CVR in Consumers' PCA, the PCA is part of the settlement agreement and includes the ZRCs associated with CVR as well as preapproval of related capital investments in CVR that Consumers will incur in the next three years. *Id*. The ALJ's contrary recommendation that the CVR proposal be rejected is not grounds for rejecting the settlement agreement, Mr. Blumenstock continues. *Id*., p. 3053. Similarly, Mr. Blumenstock asserts that the Commission should reject Mr. Lucas' arguments regarding the quantities of EWR and DR in the PCA as well as Consumers' EV forecast because those amounts have already been agreed upon in the settlement agreement. *Id*. Further, even if Consumers did have a capacity need, that need should be addressed through competitive bidding proposed in the settlement agreement. *Id*., p. 3051.

Addressing SEIA's claim that approval of the settlement agreement will harm its members, Mr. Blumenstock testifies that SEIA has failed to demonstrate any such harm. He opines that the

settlement agreement preserves the PURPA rights of QFs. He suggests that the PURPA issues SEIA attempts to raise in its objections are complex issues that involve more parties than those involved in this case and those issues should be resolved in other PURPA-related cases. *Id*., p. 3054. Further, Mr. Blumenstock points out that the settlement agreement provides SEIA's members with significant opportunities to invest in Michigan.

Mr. Maddipati's rebuttal testimony focuses in part on the settlement agreement's inclusion of an FCM on PPAs for new capacity. Mr. Maddipati disagrees with SEIA's position that an FCM is against the public interest. He explains that Mr. Lucas' testimony criticizing the FCM repeats the same criticisms that were already refuted in this case. Mr. Maddipati further asserts that Mr. Lucas wrongly relies on the ALJ's proffered reasons for rejecting the FCM set forth in the PFD, because the FCM envisioned in the settlement agreement is different than the one Consumers initially proposed in this case. 10 Tr 3094. Further, Mr. Maddipati notes that the parties to the settlement agreement found that the agreed-upon FCM "would be reasonable and in the public interest." *Id*. Mr. Maddipati reiterates the company's rationale for an FCM by quoting his rebuttal testimony in Consumers' case-in-chief. Mr. Maddipati also notes the testimony of Paul Proudfoot acknowledging that, without such an incentive, it may be difficult to expect Consumers to enter into thousands of megawatts of PPAs for solar resources in part because the utility has little opportunity to earn a return on those PPAs. *Id*., p. 3095. Mr. Maddipati notes that ABATE offered testimony in support of an FCM and noted that an FCM can compensate the utility for the additional credit risk it faces when entering into a PPA for new capacity. *Id*. Mr. Maddipati also quotes the testimony of MEC/NRDC/SC that a rationale exists for an FCM to encourage the utility to consider PPAs where they make sense by compensating Consumers for the lost opportunity to increase share value. *Id*., p. 3096. Mr. Maddipati repeats that an FCM "would potentially mitigate

some of the negative credit impacts of PPAs." *Id*., p. 3097. Additionally, Mr. Maddipati explains that the FCM agreed upon in the settlement agreement is significantly less than the incentive Consumers initially proposed and is not calculated using imputed debt but is based on a simple multiplication of Consumers' weighted average cost of capital (WACC) based on its total capital structure and PPA payment. *Id*. Mr. Maddipati states that there is no support for any contention that the agreed-upon FCM somehow disadvantages third-party developers because Consumers is required to procure at least 50% of its new capacity from PPAs through competitive solicitations. Mr. Maddipati further explains that Attachment B to the schedule represents a maximum which limits the potential FCM that could be earned and does not represent a minimum as Mr. Lucas implies. Mr. Maddipati points out that the agreed upon FCM is subject to ongoing Commission review in subsequent IRP cases. Mr. Maddipati disagrees with Mr. Lucas that it is not in the public interest to extend the FCM to PURPA contracts, explaining that the impact on credit that PPAs have exists whether those PPAs arise from competitive bidding or from obligations under PURPA. *Id*., p. 3099. Finally, Mr. Maddipati disagrees with Mr. Lucas that it will be highly unlikely that competitively-solicited Consumers-owned projects will be cost competitive with third-party projects, because competitive bidding addresses this concern and the company and its customers will benefit from utility ownership of solar assets.

Mr. Torrey's testimony focuses on why the settlement agreement is in the public interest, represents a fair and reasonable resolution of this proceeding, and is supported by substantial evidence on the record as a whole. Mr. Torrey explains that the 11 parties that signed the settlement agreement "overwhelmingly represent the public interest" because they represent the utility, the regulator, environmental groups, independent power producers including renewable generation companies, large customers, industrial customers, and residential customers. 10 Tr

3076. Mr. Torrey describes each of these 11 parties and their interests in detail. *Id*., pp. 3076-3082. According to Mr. Torrey, these 11 parties "represent a broad, diverse group of Michigan-focused parties advocating for the economic and environmental interests of Consumers Energy's electric customers and the state of Michigan." *Id*., p. 3082. Another focus of these parties, Mr. Torrey continues, is on ensuring that Consumers' customers are provided with reliable electricity. He further points out that no in-state constituencies opposed the settlement agreement. *Id*., p. 3083.

Mr. Torrey disagrees with Mr. Lucas' claim that 19 parties did not sign the settlement agreement and therefore that 2/3 of the parties did not support it. He explains that signing a statement of non-objection is not a statement in opposition to the settlement agreement and notes that nine parties signed a statement of non-objection. Mr. Torrey goes on to note that one party chose not to sign any statement in support or in objection to the settlement and that another party withdrew from the proceeding altogether. Mr. Torrey points out that only SEIA and Cypress Creek, a SEIA member, objected to the settlement agreement. Next, Mr. Torrey asks the Commission to consider the fact that "many" of the nine parties that signed the statement of non-objection actively participated in the settlement process and the settlement agreement addresses concerns and positions that these parties advanced. He further requests that the Commission consider the fact that, of the 23 parties remaining in this case, 20 have either signed the settlement agreement or indicated that they do not object to it. *Id*., p. 3084. Mr. Torrey also asserts that, because the settlement agreement represents a compromise reached by a substantial portion of the parties in this case, it represents a fair and reasonable resolution of this proceeding. He explains that testimony presented on behalf of Consumers, ABATE, and the Staff supports this assertion.

Mr. Torrey further notes that ELPC *et al*. filed testimony finding the settlement agreement to be in the public interest. He explains that a finding that the settlement agreement is in the public interest is all that Rule 431 requires for the Commission to approve it. He further states that it is unnecessary and inappropriate for the Commission to consider what additional terms could be added to the settlement agreement in order for ELPC *et al*. to sign it. *Id*., pp. 3086-3087. Adding terms or conditions to the settlement agreement deprives the parties of the benefit they bargained for in negotiating its terms, Mr. Torrey continues. He further points out the provision in the settlement agreement that states that if the Commission modifies it, it shall be deemed withdrawn. *Id*. Mr. Torrey therefore discourages the Commission from accepting any of SEIA's proposed modifications to the agreement. Mr. Torrey emphasizes that SEIA's members maintain the ability to advocate for their perceived rights to the avoided cost rates set forth in Case No. U-18090 in other proceedings. Finally, Mr. Torrey testifies that the settlement agreement is supported by substantial evidence on the whole record. *Id*., p. 3088. Mr. Torrey ends his testimony by concluding that because the public interest is adequately represented by the parties who entered into it, because the settlement agreement is in the public interest, and because it represents a fair and reasonable resolution of this proceeding and is supported by substantial evidence on the record as a whole, the Commission should approve it. *Id*., p. 3089.

The last witness to offer rebuttal testimony on behalf of Consumers, Keith Troyer, discusses SEIA's testimony about Consumers' obligations under PURPA, Consumers' REP, the cost impacts of competitive solicitations, PURPA capacity need demonstration, PURPA avoided cost issues, harm to SEIA, and SEIA's 800 MW proposal to allegedly resolve issues related to projects in Consumers' interconnection queue. To begin, Mr. Troyer disagrees with Mr. Lucas' assertion that the settlement agreement fails to acknowledge Consumers' obligation to contract with PURPA

QFs and is not in the public interest. Instead, Mr. Troyer explains that Consumers' obligation to purchase from QFs up to 20 MW in size is "a complex issue." 10 Tr 3058. He continues that, although a QF is entitled to a certain avoided cost rate based on the date that an LEO is established, this proceeding does not address whether or not a QF has established an LEO. *Id*. Because paragraph 12 of the settlement agreement preserves the legal right of any QF to file a claim with the Commission in a separate proceeding regarding its rights under PURPA, Mr. Troyer believes the assertion that the settlement agreement ignores QF obligations is incorrect. *Id.* He points out that Cypress Creek, SEIA's most vocal member in this case, has initiated such a claim by filing a complaint with the Commission on April 5, 2019.

Mr. Troyer notes that Consumers included 150 MW of PURPA contracts in its PCA. He states that Geronimo Energy (Geronimo) challenged the Commission's October 15, 2018 order in Case No. U-18090 where the Commission required Consumers to execute contracts at the full avoided cost rates for the first 150 MW in the interconnection queue. He further notes that Consumers submitted a filing asking the Commission to rescind its PURPA avoided cost rates in Case No. U-20469 and submitted a request in Case No. U-18090 to rescind the 20-year Standard Offer contract that it approved in Case No. U-18090. Despite these challenges, Mr. Troyer observes that the PCA agreed upon in the settlement agreement maintains the assumption that 150 MW will be purchased from QFs. Mr. Troyer continues that, just being within the first 150 MW of Consumers' interconnection queue does not, in and of itself, establish an LEO. He explains that, because Michigan does not have formal rules for establishing an LEO at this time, these issues are addressed on a case-by-case basis. *Id*., p. 3059. To illustrate the complexity of the issues that surround the establishment of LEOs, Mr. Troyer uses the Cypress Creek complaint in Case No. U-20516. He notes that Cypress Creek seeks contracts for 256 different limited liability

companies and that the facts and circumstances pertaining to each company's project must be evaluated independently to determine if an LEO has been established. Mr. Troyer concludes that, because the record in this case does not specifically address these projects, or any other projects in the interconnection queue, these issues should be resolved in Case No. U-18090, Case No. U-20469, the complaint proceedings, or elsewhere. *Id*., p. 3060. It is therefore premature, in Mr. Troyer's opinion, to assert that Consumers must contract with QFs in the queue, because this depends on whether the Commission finds that the QFs in the interconnection queue have established an LEO.

Regarding Mr. Lucas' claims that Consumers has been intentionally impeding development of new QFs by delaying interconnection requests, Mr. Troyer contends that this issue is not relevant to Consumers' IRP and there is no evidence in the record pertaining to this issue. Rather, Consumers' request for a partial waiver of the interconnection standards is addressed in Case No. U-20444. *Id*., p. 3061. Mr. Troyer next responds to Mr. Lucas' assertion that the Commission's approval of Consumers' PCA before resolving outstanding PURPA queue issues can result in over-procurement of capacity, unnecessary costs, and that this is not in the public interest. Mr. Troyer states that Mr. Lucas assumes that QF projects in Consumers' interconnection queue are eligible for rates set forth in Case No. U-18090. But, Mr. Troyer points out that Consumers does not agree that these facilities have established an LEO. Mr. Troyer states that there is no evidence to support Mr. Lucas' assumptions. He continues by noting that, even if Mr. Lucas is correct and Consumers executes PURPA contracts, Consumers will have the flexibility to adjust the "solar glide path" in a future IRP filing. *Id*., pp. 3061-3062.

Mr. Troyer disagrees with Mr. Lucas that approval of the settlement agreement will result in Consumers customers paying more than is necessary for solar capacity. Mr. Troyer explains that

Mr. Lucas relies on data from the Commission's February 7, 2019 order in Case No. U-18231 to determine a LCOE up to $126 per megawatt hour (MWh) for 100 MW of company-owned solar. But, Mr. Troyer notes that a later competitive solicitation in 2018 resulted in an "average cost of economic projects at $74/MWh for Company-owned solar." *Id*., p. 6. According to Mr. Troyer, this demonstrates that the costs of solar are continuing to decline for company-owned projects. He further testifies that Consumers' 100 MW REP solar in the PCA will not cause ratepayers to overpay for solar capacity as Mr. Lucas claims because Consumers is pursuing a solar PPA to fill the 100 MW solar in 2021 that is included in the PCA. He continues that the weighted average cost of economic solar PPAs from the 2018 solicitation was $49/MWh and that Consumers is in final negotiations with a shortlist of bidders to execute a PPA at a cost less than $49/MWh. Thus, Mr. Troyer concludes that the 100 MW solar resource included in Consumers' PCA will cost the company's ratepayers less than a similar amount of capacity from PURPA-based contracts at the rates Mr. Lucas proposed. Accordingly, Mr. Troyer disagrees with Mr. Lucas' recommendation that the Commission should reject the 100 MW of REP solar.

Mr. Troyer next discusses Mr. Lucas' criticism of the 50/50 structure of the solicitation process for procurement of new supply-side resources. According to Mr. Troyer, Staff witness Paul Proudfoot proposed a capacity procurement approach in his direct testimony where 50% of new capacity would be procured from PPAs and 50% would be owned by Consumers. *Id*., pp. 3063-3064. Although SEIA had ample opportunity to voice concerns throughout this case, Mr. Troyer points out that it has remained silent until now and none of its concerns were presented in this case. He continues that the 50/50 structure was included in settlement negotiations and ensures that Consumers will not own all of assets procured through competitive solicitations.

Finally, Mr. Troyer considers it "speculative" to suggest that competitively-bid agreements will be more expensive than the Case No. U-18090 PRA capacity and energy rates. *Id*., p. 3064.

Regarding the proposed competitive solicitation process envisioned in the settlement agreement, Mr. Troyer disagrees with Mr. Lucas that the 2008 *Guidelines for Competitive Request for Proposal for Renewable and Advanced Cleaner Energy*, which the Commission adopted in Attachment D of its December 4, 2008 order in Case No. U-15800 for all competitively bid projects in an REP, are insufficient to address shortfalls and risks associated with the competitive solicitation process.[7] Instead he asserts that they provide an adequate starting point for these solicitations. Further Consumers will use an independent evaluator to conduct the issuance, evaluation, and ranking of the proposals for both the PPA and company-owned portions of the solicitation. Further, Consumers has agreed to solicit feedback from stakeholders both before and after the first solicitation. With respect to SEIA's proposed procedures found in Attachment A to SEIA's initial brief, Mr. Troyer states that these procedures were not provided as record evidence in this proceeding.

Mr. Troyer disagrees with Mr. Lucas' testimony that the proposed changes to PURPA are not supported by the record. Beginning with the five-year capacity demonstration period in the settlement agreement, Mr. Troyer states that a 10-year period undermines the competitive solicitation process and results in ineffective capacity planning. He further notes that there was evidentiary support for the five-year period in Staff witness Jesse Harlow's direct testimony. Mr. Troyer also disagrees with Mr. Lucas' statement that, if Consumers failed to conduct competitive

[7] The 2008 *Guidelines for Competitive Request for Proposal for Renewable and Advanced Cleaner Energy*, which the Commission adopted in Attachment D of its December 4, 2008 order in Case No. U-15800 for all competitively bid projects in an REP are often referred to throughout this order as the "guidelines approved in Case No. U-15800."

solicitations, the five-year period becomes effective. Mr. Troyer explains that the settlement agreement requires Consumers to immediately offer any capacity not filled through competitive solicitations to QFs, regardless of whether a capacity need exists. *Id*., p. 3066.

In addition, contrary to Mr. Lucas' claim that no information was presented to change the 20-year contract term to either a 10-year forecast or 15-year actual pricing, Mr. Troyer states that both he and Mr. Harlow supported a five-year contract term for forecasted pricing and a 15-year term for actual pricing in their direct testimony. The 10-year contract term was a concession that was reached during settlement negotiations. Mr. Troyer also points to language in paragraph 7 of the settlement agreement that gives QFs that receive PPAs at the full avoided rate the same contract term length as that in competitively-bid PPAs and that further provides the maximum term length of competitively bid contracts will be equal to the depreciation schedule of a similar company-owned asset, which, for solar projects, is currently 25 years. *Id*., p. 3067. Mr. Troyer also disagrees with Mr. Lucas that the Commission should require a full 10-year LMP forecast and notes that any modification will void the settlement agreement in its entirety. *Id*., p. 3068.

Mr. Troyer also disagrees with Mr. Lucas' assertion that the public interest cannot be represented through a settlement agreement that contains no solar QF developers or trade association for solar companies, pointing out that Consumers' PCA, as modified, adds 6,000 MW of new solar capacity over the next 20 years. Mr. Troyer asserts that this does not harm solar developers or their trade associations. Further, the settlement agreement gives any QF up to 20 MW in size the ability to participate in competitive solicitations regardless of what technology is being solicited. Further Mr. Troyer maintains that the economic benefits that will result from the settlement agreement will be provided regardless of the size of the solar generation facility. *Id*.,

p. 3069. Moreover, Mr. Troyer does not believe that the settlement agreement's failure to address the uncertainty of existing QF projects in the queue results in harm to SEIA's members, because their PURPA rights are preserved. In response to Mr. Lucas' point that QF developers have spent millions of dollars on pre-development efforts, Mr. Troyer points out that there are costs associated with determining the feasibility of solar projects and that Consumers should not be forced to enter into PPAs because QF developers have taken on speculative risks in the pursuit of finding viable projects. Mr. Troyer points out that PURPA establishes an avenue for solar developers to create an obligation for the utility through the formation of an LEO.

Mr. Troyer disagrees with SEIA's proposal to resolve the issue related to existing QF projects in Consumers' interconnection queue because he asserts that it is not supported by any evidence in the record. *Id*., p. 3071. According to Mr. Troyer, this is an attempt to dedicate an amount of capacity to benefit solar developers and will result in higher costs than the bids Consumers will receive through competitive solicitations as provided for in the settlement agreement. He again points out that any modification of the settlement agreement's terms would void the settlement agreement. Regarding Mr. Lucas' assertion that failure to address the rights of existing QFs will result in protracted litigation, Mr. Troyer explains that there is no evidence presented in the record to permit the Commission to rule on the establishment of an LEO by QFs in the interconnection queue. Further, because SEIA cannot bind its member companies, Mr. Troyer questions how its proposal could truly resolve the issues Mr. Lucas raises. Accordingly, Mr. Troyer disagrees with Mr. Lucas' arguments regarding the settlement agreement or that it should be modified in any way that Mr. Lucas proposes.

3. Solar Energy Industries Association, Inc.

SEIA responds to the direct testimony presented by ABATE and ELPC *et al*. First, Mr. Lucas points out that SEIA represents the interests of Michigan ratepayers because five of its member companies do business in Michigan, and these companies employ individuals who live in Michigan. Mr. Lucas explains that SEIA advocates for the interests of its member-companies in regulatory matters. Further, Mr. Lucas considers the concern to be irrelevant to the proceedings because there is no requirement that all the parties to the proceeding represent the interests of in-state ratepayers.

Next, Mr. Lucas addresses the claim that the settlement agreement requires all new resources to be competitively bid. He points out that DR, CVR, and EWR, which will provide peak load reductions, are costs not subject to future competitive bidding, and the magnitude of that reduction is not the result of available cost-effective bids. In addition, Mr. Lucas asserts that ABATE's statement that the results of competitive solicitations will define the avoided cost for any PURPA-based PPA is false. He continues that the settlement agreement does not require competitive bidding for existing QFs. 10 Tr 2981. Mr. Lucas further explains that the inclusion of a competitive solicitation process does not resolve the rights of existing QFs and does not account for any of the QF capacity that will be coming online in the future. And, Mr. Lucas further asserts that there is no basis for ABATE's claim that the settlement agreement requires that Consumers acquire capacity through "build-own-transfer agreements." Mr. Lucas further explains that with such a project, a third-party developer would typically own the project until the 6th year of operation in order to earn a fully-vested federal investment tax credit. He further testifies that, including a three-year timeline between competitive solicitation and commercial operation, such a project will not enable Consumers to place the asset into its rate base (and begin earning a return)

until nine years after the competitive solicitation took place. Mr. Lucas also discusses Consumers' testimony where it states an intention to enter into build-transfer agreements where the developer builds the project and then sells it to Consumers. Mr. Lucas further states that, at no point in its testimony did Consumers indicate it would actively pursue "build-own-transfer" projects. Mr. Lucas recommends that the Commission require Consumers to either eliminate an arbitrary preference for company-owned projects altogether or shift competitive procurement much more heavily towards third-party PPAs and away from company-owned projects. *Id*., p. 2985. Mr. Lucas testifies that there is no basis for the claim that Consumers' customers could be paying between $95 and $110/MWh for new capacity under long-term PURPA PPAs. He further asserts that ABATE's support for the settlement agreement also supports above-market payments and other additional unnecessary costs that Consumers' ratepayers will have to pay.

Regarding the FCM, Mr. Lucas argues that there is no basis for ABATE's claims regarding the FCM's impact on Consumers' financial strength. Mr. Lucas reviews ABATE's early arguments against the inclusion of an FCM and notes that the ALJ addressed several of the issues that ABATE discussed in its testimony. Mr. Lucas does not believe ABATE's concession on this issue in reaching a compromise that permits the Commission to take the FCM into account in determining the utility's overall cost of capital in future rate cases will ensure that future rates are more just and reasonable. *Id*., p. 2989. Rather, he asserts that the plain language of the settlement agreement limits the Commission's ability to consider the impact of the FCM to only imputed debt matters. *Id*. Mr. Lucas restates the ALJ's finding that the risk of imputed debt was massively overstated and reasons that allowing the Commission to consider the FCM in the context of imputed debt provides little actual benefit. Regarding ELPC *et al*.'s direct testimony, Mr. Lucas agrees with ELPC *et al*. that the settlement agreement contains some beneficial provisions and that

a solar-focused approach to meeting future needs is in the public interest. He also agrees with ELPC *et al*. that the PURPA-related issues are "a key missing piece to the settlement agreement" and that any path forward must include a satisfactory resolution of those issues. Mr. Lucas concludes by stating that no party presented compelling evidence that the settlement agreement is in the public interest and that it represents a fair and reasonable resolution to this proceeding. Therefore, he urges the Commission to reject it unless the Commission includes as a condition of approval that the settlement agreement be modified to include SEIA's proposal to direct Consumers to contract with 800 MW of new QF projects in Consumers existing interconnection queue at the currently-in-effect U-18090 avoided cost rates. *Id*., p. 2993.

III. Initial Briefs

A. Solar Energy Industries Association, Inc.

SEIA argues that the proposed settlement agreement is not in the public interest and does not represent a fair and reasonable resolution of the proceeding consistent with state and federal law. Specifically, SEIA points out that the settlement agreement fails to address the rights of QFs under PURPA to contract with Consumers at the Commission's established energy plus MISO PRA rate where Consumers does not have a current capacity need. It also does not consider how capacity provided by these QFs will be treated. According to SEIA, these unresolved issues must be addressed because the Commission included PURPA implementation issues in this proceeding. SEIA requests that the Commission "reaffirm its previous orders directing Consumers, where there is not a current capacity need, to enter into contracts with QFs at the energy + MISO PRA rate and should create a process for these QFs to receive a higher payment for their capacity when it becomes needed." SEIA's initial settlement brief, p. 12.

SEIA argues that the Commission's past directive in its October 5, 2018 order in Case No. U-18090 requires Consumers to begin contracting with QFs immediately and that "the Commission should correct this non-compliance by Consumers by again ordering it to contract with QFs whose capacity is not currently needed at the energy + MISO PRA rate." *Id*., pp. 13-14. SEIA explains that, "[a]lthough the Commission has not adopted a bright-line LEO test, and has initiated a rulemaking for that purpose, that does not mean that individual QFs have been unable to form LEOs by committing to sell their output to Consumers." *Id*., p. 16. SEIA continues that, under PURPA, in the absence of a need for capacity, Consumers is obligated to contract at the "energy + MISO PRA rate" with any QFs that form LEOs before any changes are made to the Commission's implementation of PURPA. *Id*., pp. 16-17.

SEIA asserts that the settlement agreement fails to address the rights of QFs with existing projects in Consumers' interconnection queue to contract at the current "energy + PRA avoided cost rate" and that "[a]ny transition to a new PURPA regime must recognize the rights of projects formed under the existing PURPA regime." *Id*., pp. 17-18.

SEIA disagrees with the settlement agreement that Consumers' PCA is the most reasonable and prudent means of meeting the utility's energy and capacity needs over the next 15 years because, despite the utility's plans to acquire over 6,500 MW of new capacity, Consumers' PCA assumes that no more than the 150 MW mandated in Case No. U-18090 will be acquired through PURPA. SEIA explains that, if Consumers is later found to have violated PURPA and is required to acquire the PURPA capacity pending in its existing interconnection queue, the utility will "dramatically over-procure capacity to the detriment of ratepayers." *Id*., p. 18. In addition, SEIA asks that the Commission condition any approval of the settlement agreement on implementation of SEIA's proposal for addressing PURPA QFs in Consumers' interconnection queue, which is

described in detail in its filed objections to the settlement. According to SEIA, its proposal "would ensure that 800 [MW] of eligible QFs with projects in Consumers' interconnection queue as of a date certain would receive PPAs at the existing energy + MISO PRA rate, and that these projects would be reflected in Consumers' PCA." *Id*., p. 19. This 800 MW would be in addition to the 150 MW of QFs already included in Consumers' PCA. SEIA lauds this approach as eliminating the need for the Commission to determine the rights of every QF in Consumers' interconnection queue on a case-by-case basis. SEIA further claims that its approach will limit the amount of QF capacity that would move forward under PURPA and will ensure that Consumers engages in competitive bidding in the near future to acquire additional needed capacity. *Id*., p. 20.

SEIA also criticizes the settlement agreement for asserting that Consumers does not have a capacity need, contrary to the evidentiary record in this case, which it asserts demonstrates otherwise. Because the T.E.S. Filer City plant PPA amendment, that would have provided additional capacity, will now not be realized, because the Commission did not approve Consumers' proposed 100 MW of self-build solar facilities included in Consumers' REP proceeding in Case No. U-18231, and because the ALJ determined that Consumers' reliance on CVR was unreasonable, SEIA asks the Commission to find that Consumers has a capacity need in the amount of 80 ZRCs that obligates it to make full capacity payments to QFs beyond the 150 MW that the Commission previously required. *Id*., pp. 29-30. SEIA further points out that this capacity need would be even greater if the Commission were to require Consumers to use the industry standard for its electric vehicle growth forecast. *Id*., p. 22.

SEIA maintains that the settlement agreement wrongly provides Consumers with an unnecessary FCM to the detriment of ratepayers and QFs. It argues that "[t]he FCM is not in the public interest, is unwarranted and unreasonable, and is set at the highest level permitted by law."

Id., p. 31. SEIA explains that, in granting a utility a monopoly franchise to provide electric service in a defined territory, the state "does not guarantee the utility the right to build and own all the generation assets or to make a defined level of earnings." *Id*., p. 32. SEIA agrees with the ALJ that the record does not demonstrate that Consumers needs an incentive to pursue a least-cost strategy of supply acquisition and that the law requires Consumers to consider alternate sources of generation to utility-built resources. *Id*., p. 33. According to SEIA, the ALJ also correctly noted that utility-owned resources only make up 70% of Consumers' portfolio and that the law requires Consumers to consider alternate sources of generation to utility-built resources. *Id*. SEIA explains that PURPA already requires Consumers to pay QFs for capacity regardless of whether an FCM is approved. *Id*., p. 34.

SEIA argues that an FCM is not necessary to offset credit rating agencies' negative treatment of long-term PPAs. SEIA points to testimony by Mr. Lucas that "Mr. Maddipati exaggerates the effects of PPAs on the utility's imputed debt by credit rating agencies and misapplies [Standard & Poor's (S&P)] methodology." *Id*., p. 35. In addition, SEIA contends that Consumers dramatically overstated the risks of being a party to a PPA because it misapplied S&P's imputed debt methodology and asks that ratepayers pay twice for portions of the same product. *Id*., p. 35. SEIA points out that the utility does not currently have an FCM for its existing PPAs and yet, the utility's debt ratings have improved between 2010 and 2017. *Id*., p. 36.

In addition, SEIA suggests that Consumers has not quantified the rate impact of the utility's FCM proposal and is putting the interests of its shareholders above its customers. *Id*., pp. 39-40. SEIA asserts that an FCM would result in Consumers' ratepayers "providing far too much compensation to Consumers for alleged risks for which the utility is already compensated." *Id*.,

p. 38. SEIA cites Mr. Lucas' testimony that other utilities use competitive solicitations without an FCM and urges the Commission not to "view a financial incentive as a necessary precondition to realizing savings for ratepayers." *Id*., pp. 41-42. Moreover, SEIA disagrees with claims that ratepayers are protected because the Commission can reconsider the FCM in future years. It notes Mr. Lucas' testimony that the settlement agreement "only allows the Commission to consider the FCM in determining the overall cost of capital as it relates to imputed debt" and "does not provide the Commission authority of the existence of the FCM generally." *Id*., pp. 43-44. SEIA asks the Commission to either deny the FCM altogether, or alternatively to deny the application of an FCM to PURPA PPAs. *Id*., p. 34. Further, SEIA requests that, if the Commission determines that an FCM is warranted, the FCM should be applied only to the capacity portion of the PPA payments, and not to the total payments as included in the settlement agreement. *Id*., p. 38.

SEIA claims that the proposal to allow Consumers to own up to 50% of new capacity will likely result in higher costs for customers than if the utility pursued more PURPA QF projects or competitively-bid third-party PPAs. SEIA explains "it is almost assured that [photovoltaic] projects owned by Consumers will be more expensive for its customers than 20-year QF PPAs or third-party PPAs." *Id*., p. 46. In addition, SEIA notes that this proposal also subjects its customers to performance risk.

Turning to the competitive solicitation proposal contained in the settlement agreement, SEIA argues that Consumers will provide a set of guidelines for stakeholders to comment on, but there is no commitment that Consumers will heed any recommendations it receives and there is no Commission oversight or input into the process. *Id*., p. 47. SEIA explains that Consumers will then conduct its request for proposals (RFP) using the utility's own set of procedures in a first solicitation that will set the avoided cost rates applicable to PURPA QFs until they are changed.

Id., p. 47. Dissatisfied with this approach, SEIA proposes several changes to the procurement process to establish a "fair and transparent" competitive solicitation process. *Id*., pp. 48-49. These changes include an expedited stakeholder process led by the Staff, rather than the utility, that: (1) includes the establishment of an independent administrator who is the primary entity responsible for planning, evaluating, and managing the bidding process; (2) precludes any impact of an FCM or other incentive mechanism on the results of the procurement; (3) includes clear bid evaluation criteria and a defined selection process; (4) requires the Staff to develop a standard renewable energy credit price forecast to be provided as part of the RFP to be used in the financial evaluation process; (5) establishes a single clearing price auction methodology of the capacity price; (6) prohibits negative capacity prices to be bid; and (7) includes other procedures set forth in Attachment A to SEIA's initial brief in this case. *Id*., pp. 49-50.

SEIA is also opposed to the settlement agreement's adoption of a five-year capacity demonstration period for Consumers and instead argues that the Commission should maintain its existing 10-year capacity demonstration period. SEIA urges the Commission to reject Consumers' proposals for a shortened Standard Offer contract term as it has consistently done in the past. SEIA maintains that, at a minimum, if the Commission determines that a 10-year term is appropriate for PURPA PPAs, then the energy price forecast should be for the entire 10 years. *Id*., p. 56. SEIA also argues that a five-year LMP forecast (and a 10-year PPA based on that price) is "too short to provide QFs with a reasonable opportunity to attract capacity as required by FERC." *Id*., p. 57. SEIA explains that it favors QFs having the option of obtaining PPAs with pricing based on a 15-year LMP forecast for energy and MISO's PRA price for capacity. *Id*. Further, if the Commission approves the settlement agreement, SEIA asks the Commission to make clear how avoided energy costs would be determined going forward.

SEIA states that it and its members are harmed by the settlement agreement because the settlement agreement makes it significantly more difficult for QFs to develop solar facilities in Consumers' service area. SEIA also argues that the settlement agreement's "failure to address the PURPA rights of QF projects under development in Consumers' service area could result in QFs being prevented from developing those projects and losing millions of dollars in sunk investment and future business opportunity." *Id*. This, in turn will make it more difficult for QFs to compete effectively in future procurements. SEIA further explains that adding the FCM on future PPAs, including PURPA PPAs, unnecessarily increases the cost of providing independent power to the grid, which it argues will likely create resistance to that supply alternative in the future. And, SEIA continues, earmarking half of future solar procurements to Consumers-owned resources reduces the opportunity for QFs to compete and meet identified capacity needs. Further, SEIA repeats that the settlement agreement's failure to address the rights of QFs with projects pending in Consumers' interconnection queue harms QFs. *Id*., p. 58.

SEIA states that many PURPA issues "have gone unresolved at the MPSC for months" during this IRP proceeding. *Id*. It suggests that the Commission may have been holding off on issuing those PURPA orders waiting for the PURPA issues to be resolved in this case. Indeed, SEIA explains that QFs were "focused on the resolution of this IRP proceeding to address their concerns." *Id*. It notes that Consumers has failed to timely process interconnection applications and has refused to execute PPAs. When it became clear that this settlement agreement would not resolve the issues that impede QFs from advancing with projects in the queue, QFs began filing complaints at the Commission. SEIA expresses some bewilderment that parties are now advocating that the rights of PURPA QFs in the queue to sell their capacity and energy to Consumers are not integral to Consumers' IRP and should be resolved in another proceeding,

when in fact, Consumers and the Commission found PURPA issues to be "integral" to the PCA. SEIA observes that postponing the resolution of the level of QF capacity and energy Consumers must contract for under PURPA to a future proceeding "further delays the development of PURPA QFs." SEIA asserts that, with the federal investment tax credit declining, further delay "greatly reduces the likelihood that QFs projects will be developed" at all. *Id*., p. 59.

In addition, SEIA takes aim at specific language in the settlement agreement contained in Paragraph 11, which states as follows:

> If the Commission issues future PURPA-related orders in other proceedings, the impact of those orders on the Company's PCA, as approved pursuant to this Settlement Agreement, will be addressed in future proceedings, including the Company's next IRP, and will not be a basis for re-opening this Settlement Agreement.

According to SEIA, the scope and intent of this provision is unclear. To the extent that it seeks to prohibit the Commission from determining the rights of PURPA QFs in Consumers' existing interconnection queue, SEIA contends the provision is unlawful. And, SEIA points out that an existing Commission cannot bind a future Commission. It continues that, if this is the effect of the provision, then the Commission cannot approve the settlement agreement. SEIA therefore asks that the Commission "make clear that any approval of this settlement agreement will have no bearing on the Commission's future decisions regarding the rights of new PURPA QFs in Consumers' interconnection queue. . . ." SEIA states that the settlement agreement is not in the public interest and does not represent a consensus proposal among the varied parties and interests in this proceeding. SEIA points out that new PURPA QFs are not represented among the settlement agreement's signatories, even though the proposed settlement would alter the implementation of PURPA in Michigan. It asserts that the Commission should not change PURPA implementation by settlement fiat without the interests of new PURPA QFs being included and

addressed. SEIA therefore requests that the Commission reject the proposed settlement agreement, or, in the alternative, make the requested clarifications and adjustments SEIA notes in its brief. It further requests that the Commission condition its approval of the settlement agreement on inclusion of SEIA's proposal for addressing the existing QFs in Consumers' interconnection queue.

B. Consumers Energy Company

Consumers requests that the Commission approve the settlement agreement because it meets the requirements for approval under Rule 431. Consumers argues that the parties that signed the settlement agreement adequately represent the public interest. Consumers disputes the testimony of Mr. Lucas that 19 parties, or two-thirds of the parties in this case, did not support the settlement agreement. Consumers notes that 11 parties signed the agreement and that nine parties signed statements indicating they do not object to the settlement agreement. Consumers clarifies that only MCV failed to sign the agreement, sign the statement of non-objection, or object. It clarifies that only two parties objected to the agreement, specifically SEIA and Cypress Creek, a SEIA member. According to the utility, this support shows the settlement agreement adequately represents the public interest. Consumers' initial settlement brief, p. 11.

Consumers further notes that this conclusion is consistent with the Staff's and Consumers' testimony. Consumers also points out that ABATE's witness Pollock explained that the settlement agreement is supported by in-state constituencies and by parties that represent Michigan ratepayers. Consumers states that, in the past, the Commission has concluded that a utility's and the Staff's involvement in settlement alone may be sufficient to ensure that the parties adequately represent the public interests, and cites various cases before the Commission. It also references a Michigan Court of Appeals opinion where it claims the Court reaches the same conclusion. *Id.*,

p. 15. Consumers disagrees with SEIA's argument that the settlement agreement must include solar QFs to represent the public interest. Rather, it contends that the Staff can ensure that the interests of any underrepresented parties are represented in settlement.

Consumers argues that the Commission should approve the agreement because it represents a significant compromise, negotiated in good faith, that resolves the pending matter, and that meets the requirements for approval of an IRP under MCL 460.6t. *Id*., p. 17. Consumers references testimony that the settlement agreement is the most reasonable and prudent means of meeting Consumers' short- and long-term energy and capacity needs. It points to the agreement's main benefits, such as: the retirement of Karn 1 and 2 by 2023, a competitive bidding procurement process for capacity and for determining avoided costs that Consumers must provide to QFs under PURPA, a capacity procurement approach which provides that 50% of new capacity will be acquired through PPAs and 50% owned by Consumers, an FCM on PPA payments, numerous actions that Consumers must implement and items it must evaluate and consider in its next IRP, and the filing of Consumers' next IRP in June 2021. *Id*., pp. 17-18.

Further, the utility maintains that, because SEIA has not shown that the settlement agreement fails to meet the requirements of Section 6t, the Commission has no legal basis to reject it under Section 6t. *Id*., p. 19. Consumers states that the settlement agreement is supported by substantial evidence in the record. The utility further argues that SEIA's proposed modifications to the settlement agreement and SEIA's request that the Commission condition its approval of the settlement agreement on SEIA's proposal that Consumers purchase 800 MW of new QF projects from the interconnection queue are beyond the scope of the case. *Id*., p. 20. Consumers cautions the Commission that picking and choosing which provisions of the settlement agreement it agrees with and which it rejects would deprive the parties that agreed to it of the benefit they bargained

for. *Id*., p. 21. And, Consumers refers the Commission to the language of paragraph 16 in the settlement agreement, which states that "[i]f the Commission rejects or modifies this Settlement Agreement or any provision of the Settlement Agreement, this Settlement Agreement shall be deemed withdrawn." *Id*. The utility asserts that SEIA's requests to modify the settlement agreement would make it void.

Consumers also addresses Mr. Lucas' claims that the settlement agreement's failure to address the PURPA rights of QFs in Consumers' interconnection queue results in an unfair and unreasonable resolution of this proceeding that is not in the public interest. The utility cites testimony that paragraph 12 of the settlement agreement preserves the PURPA rights of QFs who are currently seeking rates set forth in Case No. U-18090. *Id*., p. 22. Consumers further asserts that the flexibility of the PCA also ensures that the utility will not over-procure capacity as Mr. Lucas suggests. *Id*., p. 23. Consumers points out that it is inappropriate to use the IRP process to litigate the PURPA rights of QFs in the interconnection queue because this is a complex area not developed in the record in this case. *Id*., pp. 23-24. The utility maintains that these issues should be resolved in other proceedings not related to the IRP and further notes that the Staff agrees.

Consumers disagrees with SEIA that the utility has a capacity need. The utility explains that approval of the PCA in the settlement agreement means that it does not have a capacity need. *Id*., p. 28. Further, even if a need did exist, Consumers argues that it should be addressed through competitive bidding. With respect to the loss of capacity from the T.E.S. Filer City PPA, Consumers points out that it will not have a capacity shortfall until 2031, that this shortfall is projected to be minimal, and that it may never materialize. *Id*., p. 29. Regarding the 100 MW of self-build solar that Consumers had requested in its REP case, the utility notes that it is actively pursuing a solar PPA to fill that 100 MW of REP solar. *Id*., p. 30. Consumers argues that this

capacity will be acquired at a cost less than a similar amount of capacity of PURPA-based contracts at rates SEIA proposed. *Id*. Regarding the capacity associated with CVR, Consumers notes that the PFD's recommendation regarding CVR is not binding on the Commission and does not provide a basis to invalidate the settlement agreement. *Id*., pp. 30-31. Further, because CVR assumptions included in the settlement agreement are based on substantial evidence and are the product of a reasonable compromise reached by the parties, Consumers asserts that the Commission should reject SEIA's argument about a capacity need.

Regarding the FCM included in the settlement agreement, Consumers asserts that it is also supported by substantial record evidence and represents a reasonable compromise based on the parties' FCM positions in the record. *Id*., p. 32. The utility notes that Mr. Lucas' arguments against the FCM are based on criticism of Consumers' initial proposal and do not discredit the FCM provided for in the settlement agreement. *Id*. For example, Consumers notes that it is not calculated using imputed debt but is based on a simple multiplication of the utility's WACC. Consumers further argues that the ALJ's recommendations in the PFD regarding the FCM addressed a different FCM and do not provide grounds for rejecting the settlement agreement. *Id*., p. 33. The utility also asserts that the credit impacts of PPAs were extensively supported by numerous parties in the record and that therefore there is a policy rationale for the FCM. *Id*. Consumers cites to testimony that it claims clarifies the purpose of Attachment B to the settlement agreement and further asserts that the actual FCM will be based on actual contracts received from the proposed competitive bidding process. *Id*., p. 34. It notes that the weighted average cost of economic solar PPAs from the company's 2018 solicitation, which was $49/MWh, serves as a reasonable proxy price for competitively bid PPAs in the near term, and these prices are expected to decline. Consumers also notes that the Commission will revisit the FCM in the company's next

IRP filing and can consider the impact of the FCM on imputed debt in future rate cases. The utility indicates that there is no support for Mr. Lucas' claim that the FCM will provide a windfall for the company. *Id*., pp. 35-36. Consumers also observes that testimony by the Staff and ABATE supports approval of the settlement agreement FCM.

Next, Consumers addresses SEIA's criticism of the 50/50 capacity procurement structure whereby Consumers may own 50% of future capacity. The utility argues that Mr. Lucas' claim that company-owned capacity will be more expensive than third-party PPAs is speculative, not based on fact, and not supported by the record. It points to a 41% reduction in solar resource LCOE between 2017 and 2018. Consumers asserts it is reasonable to expect this trend of declining solar costs to continue. The company also discusses other ancillary benefits of utility ownership of solar assets, noted in the Staff's testimony, that remain even if the cost of company-owned projects happens to exceed the price of third-party PPAs. *Id*., pp. 39-40. Consumers additionally suggests it is not procedurally appropriate for SEIA to wait until this stage in the case to object to the 50/50 capacity procurement approach.

With respect to SEIA's objections to the settlement agreement's competitive solicitation process, Consumers chides SEIA for relying on testimony that addressed the utility's initially-proposed competitive bidding approach and states that the competitive bidding process adopted in the settlement agreement is different and represents a compromise reached by the parties to the settlement agreement. *Id*., pp. 41-42. The utility argues that its commitment to use the guidelines approved in Case No. U-15800 is an adequate starting point for future competitive solicitations. *Id*., p. 42. Consumers also points out the role of the independent evaluator and the amount of stakeholder collaboration included in the settlement agreement's competitive bidding process.

And, it states that SEIA's alternative competitive bidding procedures were not included in the record in this case and are beyond the scope of this limited proceeding.

The company also dismisses Mr. Lucas' challenges to four PURPA-related issues in the settlement agreement. According to Consumers, these complaints do not refute the utility's contention that the settlement agreement is in the public interest and represents a reasonable resolution to this proceeding. The utility urges the Commission to reject Mr. Lucas' claim that the FCM should not apply to PURPA-based PPAs. Consumers alludes to testimony that shows PPAs affect the company's credit and asserts that this is the case regardless of whether the PPAs are entered into through competitive bidding or because of PURPA obligations.

Consumers further asks the Commission to reject Mr. Lucas' criticisms of the Standard Offer tariff length and the contract terms available to QFs when the company does not have a capacity need. The utility states that Mr. Lucas wrongly suggests that the Standard Offer contract term is limited to 10 years. *Id*., p. 46. Rather, the settlement agreement presents QFs with opportunities to secure PPAs with Consumers for longer terms. *Id*., p. 47. Consumers suggests that Mr. Lucas' complaints about the terms and rates available to QFs when Consumers does not have a capacity need were refuted by company and Staff testimony. The utility urges the Commission to reject Mr. Lucas' alternative proposal that would change the forecasted energy rate option to "a full 10 year forecast" because it is not supported by the record and would undermine the compromise the parties reached. *Id*., pp. 48-49. In addition, Consumers asks the Commission to reject Mr. Lucas' final PURPA-related argument that the five-year capacity demonstration period provided in the settlement agreement should be extended to 10 years, as the record demonstrates that a 10-year period would undermine the competitive solicitation process and result in ineffective capacity planning. *Id*., p. 49.

Consumers argues that SEIA has failed to establish that any harm would result from the Commission's approval of the settlement agreement. Because paragraph 12 preserves the PURPA rights of QFs, Consumers argues that there is no support for the argument that approval of the settlement agreement will harm SEIA's members. Moreover, the utility contends that it is impossible to resolve the uncertainty of existing projects in this case based on the evidentiary record presented. *Id*., p. 51. Consumers criticizes SEIA for suggesting that five of its members do business in Michigan without revealing the identity of those members in the record. *Id*., p. 51. Even if SEIA's members were harmed, the utility continues, it is questionable whether SEIA could actually remedy that harm in this proceeding. *Id*., p. 52. Finally, Consumers points to the benefits that the settlement agreement provides to SEIA's members, such as its plan to acquire approximately 6,000 MW of solar resources through 2040. Because SEIA has failed to establish harm as Rule 431 requires, Consumers urges the Commission to reject SEIA's objections and approve the settlement agreement presented in this case.

C. Michigan Environmental Council/Natural Resources Defense Council/Sierra Club

MEC/NRDC/SC argue that the settlement agreement satisfies each of the requirements under Rule 431 because it advances the public interest, is supported by substantial evidence on the whole record, and represents a fair and reasonable resolution of this IRP proceeding. MEC/NRDC/SC further assert that the settlement agreement satisfies Rule 431 because the parties who entered into the settlement agreement represent the public interest, and those who objected to it have been provided a reasonable opportunity to present evidence and arguments in opposition to the settlement agreement.

MEC/NRDC/SC assert that the settlement agreement preserves many of the beneficial aspects of Consumers' PCA, such as the retirement of Karn 1 and 2 and the replacement of their capacity

with cost-effective demand-side resources such as EWR, DR, and CVR. According to MEC/NRDC/SC, under the Commission's three planning scenarios, retiring those units in 2023 is projected to save Consumers' customers between $54 million and $611 million on a net present value (NPV) basis. MEC/NRDC/SC's initial settlement brief, p. 4. Other estimates from Consumers show a savings of between $451 million and $1.06 billion under the Commission's planning scenarios. This shows that the settlement agreements' implementation of this aspect of the PCA is in the public interest and supported by the record. *Id*., p. 5.

MEC/NRDC/SC also laud the ramp-up of solar capacity in the 2020s that is a hallmark of the settlement agreement and notes that the utility would develop approximately 5,000 MW of solar during the 2020s, procuring this capacity through an annual competitive bidding process with at least 50% of newly developed capacity coming from PPAs. *Id*. MEC/NRDC/SC argue that this plan will likely reduce energy costs, significantly benefitting Consumers' customers. They continue that "[b]ecause solar, demand response, and other renewable and demand-side resources can provide, reliable, cost-effective energy and capacity for the Company's customers, Consumers' plan to develop these resources will benefit the public interest." *Id*., p.6. MEC/NRDC/SC contend that this strategy of selecting renewable and demand-side resources will help the utility avoid the "substantial market risks" associated with additional gas capacity. *Id*., p.7. Specifically, these kinds of resources insulate Consumers from volatility related to relying on fuel costs outside of the company's control and from the regulatory risks of fossil generation. *Id*. MEC/NRDC/SC also state that this strategy adopts a modular approach that reduces the financial risks associated with the construction or acquisition of a large power plant. *Id*., p. 8.

MEC/NRDC/SC state that the settlement agreement addresses the most critical flaws of Consumers' proposed FCM. MEC/NRDC/SC explain how the FCM Consumers proposed in its

IRP violated Section 6t because it exceeded the WACC and was too high. MEC/NRDC/SC assert that the FCM included in the settlement agreement is "fair and reasonable, in the public interest, and consistent with the IRP statute's requirement that a financial incentive 'not exceed the utility's weighted average cost of capital.'" According to MEC/NRDC/SC, the revised FCM in the settlement agreement is less expensive and more transparent than the FCM that Consumers initially proposed. *Id*., p. 13. MEC/NRDC/SC like that the settlement agreement FCM is a simple calculation that multiplies the WACC by the PPA payment, and that the settlement agreement provides for ongoing Commission review and adjustment of the FCM in the future. *Id*., p. 14. MEC/NRDC/SC explain that the settlement agreement FCM balances fairness to customers with incentivizing Consumers to meet its capacity need through PPAs, which will minimize costs and benefit the utility's customers.

Turning to the competitive bidding process outlined in the settlement agreement, MEC/NRDC/SC assert that it is fair and reasonable, in the public interest, and supported by substantial evidence on the whole record. The parameters set for the competitive bidding process in the settlement agreement are similar or identical to the improvements that MEC/NRDC/SC have advocated for throughout this proceeding. *Id*., p. 18. They include: (1) providing the contract terms in the RFP, (2) setting the maximum term length of competitively-bid contracts so it is equal to the depreciation schedule of a similar company-owned asset, and (3) using annual solicitation technologies specified in the PCA, including solar. *Id*. Consumers also addressed MEC/NRDC/SC's concerns by agreeing to hold two competitive bidding stakeholder workshops that permit drafting, review, and editing of competitive bidding guidelines, standards, and best practices, as well as the sharing of information about the impact of the FCM on PPA bids. *Id*., p. 19. The competitive bidding terms also reflect the input from multiple stakeholders that represent

the public interest. *Id*., p. 20. Examples of this include Consumers' agreement to use a five-year period to determine capacity need (as opposed to a three-year period) and the use of a third-party independent evaluator to administer the competitive bid process. *Id*., pp. 20-21.

MEC/NRDC/SC find the 50/50 capacity procurement structure between capacity owned by Consumers and PPAs to be a reasonable compromise. They further assert that the agreement to prohibit company affiliates from bidding on the portion of Consumers' new capacity acquired from PPAs ensures that at least 50% of the new capacity will actually be from sources independent from Consumers. *Id*., p. 20. MEC/NRDC/SC suggest that the settlement agreement's competitive bidding process reflects compromise and input from various parties, such as the use of an independent evaluator and a five-year period to determine capacity need. MEC/NRDC/SC view this process as likely to result in lower costs for customers and the most efficient way to procure the necessary solar resources planned for the utility's solar ramp-up. *Id*., p. 21.

MEC/NRDC/SC argue that the settlement agreement is in the public interest because it requires Consumers to submit a revised retirement analysis of the J.H. Campbell Units 1 and 2 in the next IRP, which will be filed in June 2021.[8] This analysis will evaluate a range of potential retirement dates beginning with the year 2024, requires the utility to explain its capital expenditure and major maintenance cost projections for each retirement scenario and how its forecasted unit heat rates are consistent with cost projections. It also requires the company to apply consistent assumptions to each retirement scenario to address how capital and major maintenance costs change in the years leading up to an assumed retirement date. MEC/NRDC/SC further explain that this analysis will also include different capacity price assumptions and cost-effective resource

[8] J.H. Campbell Units 1 and 2 refers to two coal-fired generation units currently owned and operated by Consumers. These units are also referred to as "Campbell 1 and 2" interchangeably throughout this order.

options excluded from its last retirement analysis such as Michigan and out-of-state wind. In addition, MEC/NRDC/SC note that Consumers has revised its four-year time lag position regarding Campbell 1 and 2. According to MEC/NRDC/SC, the revised analysis will help ensure a robust and fair evaluation of the retirement of these coal units and advances the public interest.

MEC/NRDC/SC further assert that the settlement agreement's securitization of Karn 1 and 2 is a reasonable compromise and an improvement over the regulatory asset treatment that the company proposed initially. *Id*., p. 30. MEC/NRDC/SC point out that this allows the utility to recover the Karn 1 and 2 book balance in a way that maximizes potential savings for customers.

MEC/NRDC/SC also view the settlement agreement's resolution of certain PURPA issues in this proceeding to be a fair and reasonable resolution of those issues. MEC/NRDC/SC additionally point out that the public interest is adequately represented by the parties who entered into the settlement agreement and that the Commission's April 10 order satisfies the procedural requirements of Rule 431. MEC/NRDC/SC therefore conclude that the settlement agreement satisfies the Rule 431 standards and urges the Commission to approve it. *Id*., p. 35.

D. Staff

Like MEC/NRDC/SC and Consumers, the Staff argues that the settlement agreement meets Rule 431's requirements. The Staff points out that the Commission allowed parties to submit evidence and arguments about the agreement satisfying one criterion of Rule 431. The Staff argues that the settlement agreement satisfies Rule 431's remaining requirements because its signatories represent a broad cross section of customers and suppliers, the settlement agreement is in the public interest, fairly resolves the proceeding, and is supported by competent, material, and substantial evidence. Moreover, the Staff contends that the objecting parties failed to meet a threshold requirement of Rule 431 because they failed to state their objections with particularity

and demonstrate how the settlement agreement would adversely affect them. Pointing out that the settlement agreement does not affect or waive preexisting PURPA rights, the Staff asserts that QF projects in Consumers' interconnection queue are unharmed. Staff's initial settlement brief, p. 4.

Regarding its claim that the settlement agreement is in the public interest, the Staff argues that reducing energy waste and increasing utilization of DR and CVR will serve the public's interest in clean and affordable energy. *Id*., p. 9. The Staff points out that the settlement agreement's DR, CVR, and EWR provisions enable these carbon-neutral, low-cost, and cost-effective resources to offset lost capacity from Consumers' plans to retire Karn 1 and 2 in 2023. The Staff continues that the settlement agreement's provisions regarding the retirements of Karn 1 and 2 and Campbell 1 and 2 will advance the public's interest in clean and reliable energy. According to the Staff, retiring Karn 1 and 2 in 2023 is in the public interest. The settlement agreement also appropriately defers the question of how Consumers should recover the unrecovered book value of Karn 1 and 2 until a later case, where Consumers agreed to seek a financing order on this issue. The Staff also praises the settlement agreement's requirement that Consumers conduct a retirement analysis of Campbell 1 and 2 in its next IRP using several assumptions outlined in the settlement. The Staff views this required compromise as a fair resolution of the issue that benefits the public by establishing parameters for a retirement analysis. *Id*., p. 13.

The Staff next argues that the competitive bidding process and 50-50 ownership split envisioned in the settlement agreement will benefit the public. The Staff calls the proposed competitive bidding process the "hallmark" of Consumers' plan and the "centerpiece" of the settlement agreement. *Id*., p. 14. According to the Staff, the company's plan to use competitive bidding to procure solar generation in small increments allows it to take advantage of declining costs of solar generation. The Staff supports the guidelines that it believes ensures the solicitation

process is "inclusive, unbiased, and transparent." *Id*., p. 15. The Staff continues that annual solicitations ensure that Consumers uses the most up-to-date costs for IRP modeling and setting avoided costs. *Id*. This allows developers to bid on large projects that allow for greater economies of scale and interconnection at the transmission level and reduces the complexity and costs of interconnection in comparison to large PURPA contracts interconnecting at the distribution level. *Id*. The Staff also specifies the many requirements of the solicitation process, such as the use of an independent evaluator, informing all bidders of the evaluation criteria and process, following RFP parameters that the Commission approved in Case No. U-15800, timely issuing an RFP through public notice, and including the terms of the contract in the RFP. The Staff additionally notes that the settlement agreement requires Consumers to follow these same procedures for future solicitations and all new company-owned supply-side resources. The stakeholder process after Consumers' first competitive solicitation and again in its first IRP review also gives the Commission an opportunity to adopt uniform standards on best practices for competitive bidding and RFPs that all utilities can use, the Staff explains. *Id*., p. 17.

The Staff also views the 50/50 resource split to be in the public interest as it continues a 50% limitation on company-owned resources that was included in 2008 PA 295 and that led to increased competition and reduced prices for Michigan customers. *Id*., p. 18. The Staff also observes that, under the terms of the settlement agreement, Consumers' affiliates are prohibited from bidding on the portion of new capacity to be acquired from PPAs. The Staff points out that 50% resource ownership permits Consumers to have greater control over the maintenance and operation of the equipment, greater insight into the performance of the equipment, and better equips the utility to forecast the output from solar resources. *Id*., p. 19. Knowledge about the location of such company-owned resources also allows Consumers to better coordinate generation

and transmission planning going forward. *Id*., p. 20. The Staff continues that, by adopting a 50/50 capacity procurement structure, the parties receive the benefits of competitive solicitation and the benefits of coordinated generation and transmission planning.

The Staff asserts that the five-year planning horizon for determining a capacity need is a compromise that serves the public's interest in administrative efficiency because it aligns this horizon with the IRP filing requirements in Section 6t, which require an IRP to be filed every five years. *Id*., p. 21. Turning to the FCM included in the settlement agreement, the Staff asserts that the FCM benefits the public because it helped to facilitate settlement. Although the Staff opposed Consumers' initial FCM that it presented in its IRP, the Staff supports approval of the settlement agreement and points out that the current FCM included in the settlement agreement's terms is not tied to imputed debt, is far lower than what Consumers initially proposed, and fosters competition by making the competitive bidding process in the settlement agreement possible. The Staff notes that a 5.88% WACC FCM falls squarely in the middle of the range that Staff witness Jesse Harlow recommended in his proposed alternative incentive. The Staff asserts that approval of a financial incentive was pivotal for Consumers' agreement to change its business model and purchase at least half of new generation from third parties. For these reasons, the Staff asserts that the incentive benefits the public. *Id*., p. 25.

Regarding SEIA's criticisms of the settlement agreement, the Staff points to the testimony of Staff witness Paul Proudfoot, who on the issue of PURPA, testified that, although this was the right case to address PURPA avoided costs, it is the wrong forum to resolve QF claims about projects in Consumers' interconnection queue. The Staff explains that, unlike PURPA avoided costs, queue issues depend on determinations made in other cases. For example, the Staff points out that they depend on the Commission's definition of an LEO and guidance on how to manage

queue projects in Case No. U-20344. The Staff suggests that SEIA's members also need to know if the distribution grid is robust enough to support electric connections without extensive and costly upgrades, which they may not know. *Id*., p. 26. And, the Staff opines that requiring Consumers to purchase power from projects in the interconnection queue at this time would pose a risk to ratepayers. *Id*. Therefore, the Staff believes the parties to the settlement agreement properly declined to address PURPA queue issues. It continues that the parties were also right to clarify in the settlement agreement that the settlement does not waive PURPA rights that existed before the settlement agreement. *Id*., p. 27.

Regarding SEIA's position that Consumers has a capacity need, the Staff disagrees. According to the Staff, it is premature to remove most of the ZRCs that SEIA recommends be removed from Consumers' capacity outlook for the same reasons that Consumers provided in its rebuttal testimony and initial brief. Therefore, the Staff argues that there is no basis to conclude Consumers will have a capacity need before 2031, and, if it does, that need will be short-lived. *Id*. For all of these reasons, the Staff urges the Commission to approve the settlement agreement.

E. Independent Power Producers Coalition

In its initial brief, IPPC expresses its support for the settlement agreement stating that it resolves IPPC's concerns with Consumers' IRP, and Consumers' accompanying PCA, as applied to IPPC members. IPPC also supports Commission approval because the settlement agreement will lead to the use of third-party, independently-owned renewable energy resources including IPPC members' existing QFs. This, in turn, resolves IPPC's involvement in several other Commission cases, including Case No. U-18090; Consumers' February 4, 2019 application to rescind Case No. U-18090's established avoided costs in Case No. U-20469, and the complaint

case that IPPC filed against Consumers pursuant to PURPA in November 2015, in Case No. U-17981. IPPC's initial settlement brief, p. 2.

IPPC next addresses SEIA's criticism that the FCM is unreasonable and should be rejected. IPPC disagrees with SEIA's position on this issue and asserts that the FCM appropriately complies with the statutory requirements for such an incentive, is necessary for QFs and, as structured in the settlement agreement, represents sound policy. To start, IPPC reasons that, just because the law requires Consumers to enter into certain PURPA PPAs "does not mean that those agreements will seamlessly occur." *Id*., p. 3. Without such an incentive in place, IPPC suggests that utilities like Consumers will resist entering into 20-year long-term contracts with PURPA QFs. IPPC explains that, despite the fact that SEIA claims Consumers is obligated and required under federal and state law to enter into PURPA PPAs with IPPC's members, IPPC's member QFs have been seeking new or renewed PURPA PPAs with Consumers for six years. Consumers' reluctance to enter into reasonable PPAs with IPPC's member QFs is the reason IPPC filed a complaint against Consumers in 2015 and suggested to the state Legislature that utilities be allowed to earn a reasonable incentive on PPAs. IPPC further notes that its suggestions led the legislature to adopt such incentives as set forth in Section 6t(15). IPPC emphasizes that, in enacting this statutory provision, the Legislature placed no restrictions on PURPA PPAs. Thus, IPPC reasons, the Legislature clearly considered the fact that the Commission may approve a reasonable financial incentive for PURPA PPAs and found that such incentives would be in the public interest. IPPC asserts that the FCM as proposed in the settlement agreement is reasonable and prudent and should be adopted.

Next, IPPC disagrees with SEIA's assertion that the public interest was not adequately represented by the parties to the settlement agreement and that the settlement agreement will cause

material harm to SEIA's members. IPPC states that paragraph 7g of the settlement agreement is not a new avoided cost provision but simply restates what the Commission already ordered in its May 31, 2017 order in Case No. U-18090, and favors the renewal of existing QF contracts. According to IPPC, paragraph 7g of the settlement agreement is neither discriminatory nor "harmful" to SEIA's members because the Commission found that the same opportunities for contracts at full avoided costs, regardless of Consumers' capacity needs, apply to the first 150 MWs of new QF capacity in Consumers' interconnection queue. *Id*., p. 6. IPPC explains that the Commission determined in that case that the 150 MW limit only applies to new QFs and not to existing facilities that are out-of-contract. IPPC observes that paragraph 7g of the settlement agreement is consistent with the Commission's previous directives in Case No. U-18090 and is not more generous to existing QFs than to a significant number of new QFs and should not be construed as a limiting factor for new QFs. Nevertheless, IPPC states that if SEIA had serious concerns about the limitation on the 150 MW of contract capacity being available for new QFs or the Commission's determination that existing QF contracts should be renewed at full avoided cost, it should have raised those issues on appeal or rehearing of the orders in Case No. U-18090. *Id*., p. 8. IPPC views paragraph 7g to be fair and reasonable to both existing and new QFs and recommends its adoption as part of the full settlement agreement in this case. Last, IPPC argues that its member QFs represent the hallmarks of a public interest standard envisioned in both the Commission's Rules of Practice and Procedure and PURPA's public interest requirements, that it was properly a signatory party to the settlement agreement, and that its support of the settlement agreement ensures that it meets the requisite public interest standards needed for Commission approval. *Id*., p. 14. Because the settlement agreement represents a fair and reasonable resolution of this proceeding, because IPPC member QFs reflect the public interest of the state, and because

the settlement agreement will ensure continuation of these vital renewable energy QFs in this state, IPPC contends the settlement agreement is in the public interest and should be approved. *Id*.

F. Attorney General

The Attorney General first summarizes the major components of Consumers' PCA as initially filed as part of its IRP. Next, the Attorney General summarizes the settlement agreement's provisions. The Attorney General argues that the Commission should approve the proposed settlement because it represents a reasonable and prudent outcome. The Attorney General notes that, although the settlement agreement represents a divergence from Consumers' traditional approach to providing energy, it allows for further review and has safeguards built in to protect ratepayers. For example, the Attorney General points out that Consumers agrees to file another IRP in approximately two years, which will provide interested parties with an opportunity to review Consumers' resource mix and plans. The Attorney General additionally notes that Consumers has committed to addressing a number of issues in the next IRP that will further inform the parties of the reasonableness of this and future plans. Moreover, the Attorney General points out that any IRP-related expenditures sought in future rate cases will still be subject to a reasonableness and prudence review. Accordingly, the Attorney General urges the Commission to approve the settlement agreement. Attorney General's initial settlement brief, p. 10.

G. Association of Businesses Advocating Tariff Equity

ABATE urges the Commission to approve the settlement agreement because it satisfactorily resolves many of ABATE's initial concerns with Consumers' IRP and PCA, is the result of substantial negotiations and reflects numerous compromises, is in the public interest, and meets the criteria set forth in Rule 431. ABATE's initial settlement brief, p. 2. ABATE asserts that the language of the settlement agreement does not substantiate SEIA's claim of harm to its members.

Further, ABATE notes that QFs feeling aggrieved by the settlement's provisions may still seek appropriate redress by initiating formal complaints. *Id*., p. 6. According to ABATE, Mr. Lucas' claim that the settlement agreement "kicks the can further down the road on the existing projects" does not establish harm. *Id*. ABATE also points out that the issues SEIA wants addressed in this proceeding are complex, involve non-parties to this case, and should be resolved on a case-by-case basis in other proceedings. ABATE also disputes SEIA's assertion that, in order for the settlement agreement to represent the public interest, solar QF developers or the national trade association of the United States solar energy industry must be included as signatories, noting that those entities do not represent the interests of ratepayers living and working in Michigan. *Id*., pp. 6-7.

ABATE points to Consumers' rebuttal testimony that explains why the millions of dollars QFs may have spent on pre-development efforts should not result in the utility or ratepayers being forced to enter into PPAs. ABATE also disputes SEIA's point that allowing Consumers to own up to 50% of its future capacity additions will be more expensive for Consumers' customers. *Id*., p. 7. In addition, ABATE takes issue with SEIA's statement that "nearly 2/3 of all parties did not support the settlement agreement," pointing out that this incorrectly leads the reader to believe that more parties opposed the settlement agreement than supported it. *Id*., pp. 7-8. With respect the requirement in Rule 431 that parties opposing settlement be given an opportunity to present evidence and argument, ABATE notes that parties were given this opportunity as required by the rule. Regarding the rule's requirement that the public interest be represented by the settling parties, ABATE asserts that both the Staff and the Attorney General represent the public interest and that this requirement set forth in Rule 431(5)(b) has been satisfied. Further, ABATE states that the settling parties expressly agreed that Commission approval of the settlement agreement would be reasonable and in the public interest. Also, ABATE argues that because the settlement

agreement was a compromise reached by a substantial portion of the parties in the case, it is a fair and reasonable resolution of the case. *Id*., p. 10. It is also the most reasonable and prudent plan to meet Consumers' future energy and capacity needs.

ABATE claims that securitizing the unrecovered book balance of Karn 1 and 2 is better for ratepayers and allows Consumers to immediately recover the unamortized book value without earning a return. *Id*. It is also a low-cost method of financing that uses 100% debt with no equity or associated income taxes. *Id*., p. 11. Regarding the competitive bidding process included in the settlement agreement, ABATE contends that the lower costs resulting from competition in this process will benefit all ratepayers in Consumers' service territory. ABATE describes various aspects of the process that benefit customers, including: the stakeholder process, the use of an independent evaluator, the use of guidelines for RFPs approved in Case No. U-15800, and various action items that Consumers must complete before filing its next IRP. *Id*., pp. 11-12.

ABATE also points out that updating the avoided cost methodology to incorporate competitive bidding will result in ratepayer savings. It explains that the PURPA determinations made in Case No. U-18090 are outdated and in need of updating. ABATE considers the fact that competitive solicitations will define avoided cost for any new PURPA-based PPAs to be significant, because this ensures all future capacity additions are competitively priced based on current market conditions. *Id*., p. 12. ABATE suggests that the settlement agreement can keep electricity rates affordable and benefits both Consumers and its customers.

Turning to Consumers' reliance in the PCA on DR as a resource, ABATE indicates that its concerns about reliability are satisfied by the additional studies that the settlement agreement requires Consumers to conduct. ABATE praises the modular, flexible nature of the settlement

agreement's supply plan. Therefore, it asks the Commission to find that the proposed levels of peak load reduction in the settlement agreement are reasonable and cost-effective. *Id*., p. 14.

Regarding the settlement agreement's FCM, ABATE explains that, although it initially opposed Consumers' FCM in the utility's IRP filing, it supports the settlement agreement's inclusion of the current proposed FCM because it compensates Consumers for the additional cost associated with third-party PPAs, the Commission can consider the FCM in determining overall cost of capital in future rate cases, and it provides a sufficient incentive for Consumers to proceed with its plan to secure future capacity additions through competitive solicitations. *Id*., pp. 14-15. Because ABATE believes that the Commission should find the settlement agreement is in the public interest, is supported by substantial evidence on the record, and represents a fair and reasonable resolution to this proceeding, ABATE requests that the Commission approve it. *Id*., p. 16.

H. Environmental Law & Policy Center *et al*.

ELPC *et al*. argues that the settlement agreement is in the public interest because it improves on Consumers' PCA, reduces risk for Michigan customers, enhances the quality of the company's next IRP, and more effectively addresses adverse environmental impacts of carbon emissions. ELPC *et al*.'s initial settlement brief, p. 4. ELPC *et al*. recaps the testimony of Mr. Gignac describing the various ways that the settlement agreement improves on Consumers' initially-filed PCA. *Id*., pp. 4-5. It also references Mr. Gignac's testimony about the flexible nature of the utility's resource plan that accommodates variable energy resources and ensures reliability at low cost. ELPC *et al*. also notes Mr. Gignac's testimony that the phasing out of fossil fuel resources and their replacement with clean energy technologies reduces risk to customers by limiting exposure to fuel price increases and regulation of emissions. *Id*., p. 5. ELPC *et al*. further asserts

that the settlement agreement benefits the public interest by establishing modeling and process improvements for the next IRP and by accelerating retirement analyses for coal units whose carbon emissions currently contribute to climate change and whose operation adversely affects public health and the environment in many ways.

Regarding the settlement agreement's FCM, ELPC *et al*. considers this compromise acceptable given the fact that it is subject to Commission review in 2021, capped at clearly-defined amounts, and is significantly reduced from Consumers' initial proposal. *Id*., p. 6. ELPC *et al*. points out that, if Consumers cannot show over the next three years that the FCM reduces costs for Michigan customers, the Commission has the authority in Consumers' next IRP to discontinue the FCM for new contracts. It asks the Commission to clarify that its approval of an FCM as part of the settlement agreement is based only on the facts of this case, including a plan to replace virtually all of its fossil-fuel based generation with demand-side management and competitive third-party PPAs for renewable energy.

Regarding the unresolved matter of existing projects within Consumers' interconnection queue, ELPC *et al*. urges the Commission to promptly address the existing PURPA queue, well before the Commission has defined an LEO in a stakeholder process, because ELPC *et al*. believes that a failure to move projects forward will adversely affect the renewable energy market in Michigan. ELPC *et al*. does not propose a specific procedure for addressing the existing queue and does not oppose the Staff's recommendation that the Commission initiate a separate proceeding to address the existing PURPA queue. ELPC *et al*. points out that prompt resolution of this issue reduces concerns that Consumers will procure unreasonable amounts of unneeded capacity at the expense of customers. *Id*., p. 8. Additionally, ELPC *et al*. notes that the sooner this issue is addressed, the more lead time Consumers will have to adjust the solar glide path in its next

IRP filing. To conclude, ELPC *et al*. requests that the Commission find the settlement agreement is in the public interest. Instead of making changes to the settlement agreement, ELPC *et al*. argues that the Commission move swiftly to resolve issues related to Consumers' interconnection queue.

IV. Reply Briefs

A. Solar Energy Industries Association, Inc.

SEIA argues in reply that Consumers inappropriately shifts the burden of proof on the objecting parties in this case to show that the settlement agreement should not be approved, when in fact, Rule 431 makes clear that it is the settling parties who must demonstrate that the Commission should approve the settlement agreement. SEIA's settlement reply brief, pp. 3-5. SEIA reiterates its argument that resolution of the rights of QFs in Consumers' interconnection queue is inconsistent with the Commission's October 5, 2018 order in this case where the Commission decided PURPA-related issues must be decided on a "holistic" basis and further determined that PURPA issues are integral to the Commission's required determinations under Section 6t. *Id*., p. 6. SEIA asserts that PURPA issues have gone unresolved at the Commission for months, QFs held off filing complaints pending resolution of the IRP proceeding, and both Consumers and the Commission found PURPA issues to be integral to the PCA in this case. SEIA maintains that further delaying the development of PURPA QFs, with the federal investment tax credit being reduced at the end of the year, greatly reduces the likelihood that QF projects will be developed. SEIA again urges the Commission not to approve Consumers' PCA without knowing what level of PURPA PPAs Consumers is obligated to enter into with QFs in Consumers' interconnection queue as this level will affect Consumers' capacity plans. SEIA repeats that Consumers has an obligation to contract with existing QFs in its queue at the MISO PRA rate for

capacity. PURPA contracts combined with competitive solicitations will allow Consumers to immediately plan for and replace capacity lost from retiring Karn 1 and 2. SEIA further argues that, to the extent that the Commission elects in this proceeding to modify its PURPA implementation regime, those changes may not be made retroactive to QFs that had a right to PURPA PPAs with Consumers prior to such action.

SEIA also reiterates that its proposal for addressing the PURPA QFs in Consumers' interconnection queue is reasonable, supported by substantial evidence on the whole record, and has widespread support among developers with projects in Consumers' interconnection queue, and if approved, will avoid further litigation. *Id*., p. 8. SEIA again asks the Commission to condition any approval of a settlement agreement in this case on implementation of this proposal. SEIA additionally argues the proposal is supported by the record because Mr. Lucas described the proposal in testimony presented regarding the settlement agreement and it was presented in SEIA's objections. SEIA claims that the Commission can condition approval of the settlement agreement in this case on SEIA's proposal. *Id*., p. 11. SEIA continues that the proposal has the support of more than 90% of the MW in Consumers' interconnection queue. *Id*., p. 12. SEIA further describes as "unfounded and unsupported" certain claims by other parties that ratepayers will be harmed by SEIA's proposal because they will have to pay higher avoided cost rates than the rates that will result from competitive bidding. *Id*., p. 13. It contends this assertion is speculative because rates from future competitive solicitations are "unknown and unknowable." *Id*., p. 14.

Regarding the dispute over whether Consumers has a capacity need under PURPA, SEIA asserts this is a question of federal law and not a fact to be deemed true by virtue of a settlement agreement in this IRP proceeding. *Id*. SEIA further asserts that Consumers admits it is actively

pursuing 100 MW of solar to fill the 100 MW included in its REP. SEIA continues that, where Consumers has a need for 100 MW of additional solar capacity, the company has an obligation under PURPA to procure it from QFs. This, according to SEIA, is another example of how Consumers is actively procuring capacity while delaying the development of PURPA QFs. *Id*. Therefore, SEIA argues that, even if the Commission approves the settlement agreement, it should still find that Consumers has a capacity need and should quantify that need. *Id*., p. 15.

SEIA repeats that the settlement agreement provides Consumers with an unnecessary and unwarranted FCM to the detriment of ratepayers and QFs. SEIA asserts that the FCM is set at the highest level permitted by law and is not in the public interest. *Id.*, p. 16. In response to IPPC's support for applying the FCM to PURPA PPAs, SEIA asserts that Consumers' refusal to comply with PURPA and IPPC's lack of confidence in the Commission's willingness or ability to enforce the law with Consumers in a timely manner are poor policy justifications for an FCM. *Id*., p. 17. SEIA continues that awarding utilities an incentive to comply with the law just encourages those companies not to comply with the law to begin with. *Id*. SEIA stands by its position that Consumers should not be entitled to receive an FCM for complying with its obligations under federal law. Regarding the Staff's position that agreeing to an FCM was essential to achieve a settlement agreement in this case, SEIA responds that it is unclear why the signatories to the settlement agreement placed such a premium on achieving a settlement so as to agree to the FCM. *Id*., p. 18. SEIA further disagrees with the ELPC that the FCM is subject to Commission's continued review and that the Commission may discontinue it in the future. Instead, SEIA warns that the FCM terms of the settlement agreement are "carefully crafted" and restrict the Commission's future consideration of the FCM. *Id*., p. 19.

Regarding the 50/50 capacity procurement structure, SEIA maintains that the Staff presented the proposed structure in this case as an *alternative* to an FCM. SEIA continues that there is no justification to both permit Consumers to own up to 50% of new capacity additions and also receive an FCM when the reason for the FCM was to provide an incentive for Consumers to change its business model from one where the utility owned most of its generation resources to a model based on acquiring capacity and energy from third parties via PPAs. *Id*., p. 19. SEIA suggests that this 50/50 structure will not become a reality for quite some time and that, by then, ratepayers will have paid a hefty price for an increase that may only be 20% of Consumers' portfolio. *Id*., p. 20. SEIA also argues that there is no evidence to support the Staff's claim that the 50/50 structure would drive down prices. SEIA asserts that the Staff's chart presented to show the declining costs of renewable energy from 2009 to 2016 does not show that the costs declined due to utility ownership of renewable resources. *Id*. In addition, SEIA maintains that this structure subjects Consumers' customers to performance risk.

SEIA once again argues that the Commission should maintain the existing 10-year capacity planning horizon rather than approve the settlement agreement's shorter five-year period. SEIA points out that the IRP planning horizon is 15 years. *Id*., p. 21. Last, SEIA explained that its initial brief explains how the proposed settlement agreement is full of proposals that, if implemented, would harm developers of PURPA QFs and Michigan's ratepayers. *Id*., p. 22. Therefore, SEIA asks the Commission to reject the settlement agreement. Further, if the Commission approves it, SEIA requests that the Commission include the requested clarifications and adjustments noted in SEIA's initial settlement brief and add to its approval the condition that SEIA's proposal for dealing with existing QFs in Consumers' interconnection queue be implemented. *Id*., p. 23.

B. Consumers Energy Company

Consumers argues that the briefs filed by the Staff, the Attorney General, ABATE, and MEC/NRDC/SC show that the settlement agreement meets the requirements of Rule 431. Consumers further contends that both the Staff and ABATE established that SEIA was afforded a reasonable opportunity to present evidence and arguments in opposition to the settlement agreement as required by Rule 431. In addition, the utility notes that the Staff, ABATE, MEC/NRDC/SC, and IPPC also showed that the parties who entered into the settlement agreement adequately represented the public interest as Rule 431 requires. Additionally, Consumers asserts that initial settlement briefs that the Staff, the Attorney General, ABATE, IPPC, and MEC/NRDC/SC filed further show that the settlement agreement is in the public interest, represents a fair and reasonable resolution of this proceeding, and is supported by substantial evidence on the record as a whole. Consumers' settlement reply brief, p. 7. Consumers agrees with these parties for the reasons presented in its initial settlement brief, and urges the Commission to approve the settlement agreement. *Id.*, p. 10.

With respect to ELPC *et al*.'s arguments in its initial settlement brief, Consumers agrees with ELPC *et al*.'s conclusion that the settlement agreement is in the public interest, but disagrees with ELPC *et al*. to the extent that it supports SEIA's positions regarding Consumers' alleged PURPA obligation and the manner in which the projects in the queue should be resolved. *Id*. However, Consumers explains it does not oppose a resolution of these issues in a future proceeding. The utility asks the Commission to consider ELPC *et al*.'s significant involvement in the settlement and its support for the settlement agreement and suggests this shows the settlement agreement meets the criteria required in Rule 431(5). *Id*., p. 13.

Consumers asserts that SEIA's initial settlement brief fails to provide sufficient grounds for rejecting the settlement agreement. *Id*. The utility contends that SEIA's arguments are flawed because they are based on Consumers' initially-filed positions in this proceeding and not on the settlement agreement's provisions. *Id*. According to Consumers, the company already refuted these arguments in its evidence, briefs, exceptions, and replies to exceptions. *Id*. The utility also claims that SEIA's reliance on the ALJ's recommendations in the PFD was in error because the PFD does not speak for the Commission or provide a basis to invalidate the settlement agreement. *Id*. According to Consumers, SEIA failed to address any of the evidence that Consumers, the Staff, or ABATE provided in this proceeding to refute SEIA's updated positions. *Id*., p. 14. Further, the utility maintains that SEIA's proposed modifications to the settlement agreement and proposed condition that approval of the settlement agreement include the purchase of 800 MW of new QF projects from the interconnection queue are beyond the scope of this case. *Id*. Consumers further contends that SEIA's proposed modifications and condition also undermine the compromises reached in the settlement process. *Id*., p. 15. The utility suggests SEIA's positions are unreasonable, self-serving, and contrary to the terms of the settlement agreement. *Id*., pp. 15-16. Consumers restates its argument that modification of the terms of the settlement agreement render it withdrawn pursuant to paragraph 16. Because the settlement agreement meets the requirements of Rule 431, Consumers requests that the Commission approve it.

Regarding the unresolved issue of QF projects in Consumers' interconnection queue, Consumers stands by its arguments presented in its initial settlement brief. Again, the utility notes that that the settlement agreement does not impair PURPA QFs' rights and that SEIA's objections are complex and should not be considered in this IRP case. *Id*., p. 18. The utility notes that Staff and ELPC *et al*. similarly agree that this is not the appropriate forum to consider these issues. *Id*.

The utility again argues that SEIA's alternative proposal to resolve this issue is not in the record and is otherwise unreasonable because it will result in higher costs than what Consumers will receive through competitive bidding. *Id*., p. 20. And, Consumers agrees with the Staff that because neither FERC nor the Commission has established a standard for LEOs under PURPA, it is speculative to assume that any of SEIA's members have established an LEO.

Consumers stands by its arguments in its initial settlement brief regarding why the Commission should reject SEIA's position that the utility has a capacity need. *Id*., p. 21. The utility restates that approval of the settlement agreement means Consumers does not have a capacity need. Consumers continues that the Commission's review of the company's next IRP in 2021 ensures that Consumers' PCA continues to represent the most reasonable and prudent means to meet the utility's energy and capacity needs. *Id*. Consumers responds to SEIA's analysis about the need for 80 ZRCs by restating the arguments in its initial settlement brief and settlement agreement testimony. *Id*., pp. 21-23.

Turning to SEIA's criticism of the settlement agreement FCM, Consumers makes many of the same arguments that it did in its initial settlement brief. The utility states that SEIA's arguments are based on the initially-proposed FCM and not on the one that is proposed in the settlement agreement. *Id*., p. 24. Consumers again notes that the settlement agreement's FCM is substantially less than the initially-proposed FCM and is not calculated using imputed debt. *Id*., p. 25. The utility again explains that SEIA erroneously relies on the ALJ's reasoning in the PFD. Consumers argues that the company's, the Staff's, MEC/NRDC/SC's, and ABATE's testimony refutes SEIA's claims that the FCM is unnecessary and unwarranted. The company urges the Commission to reject SEIA's assertion that the FCM should not apply to PURPA-based PPAs.

Consumers also disputes SEIA's claim that the settlement agreement limits Commission review of the FCM in future proceedings.

For the reasons set forth in the company's initial settlement brief, Consumers disagrees with SEIA's assertion that permitting Consumers to own up to 50% of new capacity acquisitions will result in higher customer costs. *Id*., p. 31. Consumers further contends that the Commission should reject SEIA's attempt to rely on solar costs provided in other recently filed IRP cases because these costs are not in the record. *Id*., p. 32. Consumers explains the benefits of utility ownership of generation and asks the Commission to reject SEIA's criticism of this approach.

Consumers stands by the settlement agreement's competitive bidding process arguing that it is reasonable and the result of a compromise reached by the parties. *Id*., p. 34. The utility claims that SEIA misrepresents the stakeholder collaboration provided for in the settlement agreement. In addition, Consumers asks the Commission to reject SEIA's proposed alternative competitive bidding procedures arguing that they are not in the record. *Id*., p. 36. And, the utility points out that, in SEIA's initial brief in the IRP, SEIA argued that the guidelines approved in Case No. U-15800 should be applied to the competitive bidding procedure and the settlement agreement accomplishes this. *Id*., p. 36. The company requests that the Commission approve the settlement agreement's competitive bidding process.

Regarding SEIA's criticism of the PURPA issues resolved by the settlement agreement, Consumers urges the Commission to reject SEIA's various criticisms for the reasons set forth on pages 45 through 50 of the company's initial settlement brief. *Id*., p. 38. Consumers argues that SEIA misconstrues some of the PURPA provisions in the settlement agreement. *Id*., p. 39. For example, Consumers disagrees with SEIA's suggestion that the settlement agreement eliminates the 20-year fixed price PURPA PPA that the Commission recently adopted and replaces it with

two inferior options. The utility explains that contract terms of 25 years are still an option for QFs of a certain size. Consumers claims that it and the Staff both presented testimony refuting SEIA's arguments regarding the rates and terms available to QFs when Consumers does not have a capacity need. *Id*., p. 40. Consumers also identifies certain concessions it made in this area, such as forecasted energy rates of five years in length and the applicability of a Standard Offer contract. Moreover, Consumers argues that FERC positions on PURPA issues do not provide grounds for rejecting the settlement agreement as the resolution of many PURPA issues has been left to states. *Id*., p. 41. Consumers notes that the Staff and MEC/NRDC/SC supported the settlement agreement's PURPA avoided cost construct in this case.

Consumers urges the Commission to reject SEIA's claim of harm for the reasons discussed in the utility's initial settlement brief. *Id*., p. 44. According to the utility, SEIA has failed to establish how the settlement agreement harms its members. Further, Consumers argues that SEIA's alleged harm is based on the speculative assumption that its members qualify for rates based on the avoided cost rates set forth in Case No. U-18090. And, the utility argues that both paragraph 11 and paragraph 12 of the settlement agreement establish that Commission approval of the settlement agreement will not harm QFs. Last, Consumers disagrees with SEIA that the public interest was not adequately represented by those parties who signed the settlement agreement. The utility refers the Commission to its initial settlement brief for the reasons why the Commission should reject this claim.

C. Association of Businesses Advocating Tariff Equity

ABATE argues that the settlement agreement is fair, reasonable, in the public interest, and should be approved. Regarding SEIA's criticism of the settlement agreement's competitive solicitation process, ABATE asserts that SEIA erroneously relies on testimony directed towards

Consumers' original competitive bidding approach and not the competitive solicitation process provided for in the settlement agreement. ABATE describes in detail the three phases of stakeholder engagement designed to ensure fairness, transparency, and uniformity in future competitive solicitations. ABATE further observes that, if, as a result of the competitive bidding process put in place pursuant to the settlement agreement, the final costs are found to be significantly higher than the initially-approved costs, the Commission shall review and approve only those costs that the Commission determines are reasonable and prudent in accordance with Section 6t(12)(c). ABATE's settlement reply brief, p. 6.

ABATE further argues that SEIA fails to state its objections with particularity and in a way that demonstrates how SEIA's members would be adversely affected by the settlement agreement as Rule 431(3). In a footnote, ABATE claims that, in past Commission cases, the Commission has found that if an opposing party fails to state how its members are adversely affected by a settlement agreement, this is grounds for rejecting that party's objections. *Id*., fn. 1. ABATE notes that paragraph 12 preserves the PURPA rights of QFs and states that this shows SEIA's members were not adversely affected by the settlement agreement. ABATE further explains that it agrees with the Staff that it is speculative to assume any of SEIA's members have established an LEO. *Id*., p. 8. Because ABATE claims that SEIA has not demonstrated how the settlement agreement adversely affected its members, ABATE urges the Commission to reject SEIA's objections. *Id*. ABATE urges the Commission to reject SEIA's proposal to incorporate the 100 MW of solar from its REP into the Commission's determination of Consumers' capacity need in this proceeding. *Id*., p. 10. Instead, ABATE asserts that the Commission should find the inclusion of 100 MW of new solar resources for meeting its renewable portfolio standard (RPS) to be reasonable and prudent. *Id*., p. 11. ABATE disagrees with SEIA that the 50/50 capacity

procurement approach will result in increased costs to customers and reminds the Commission that it lacks the statutory authority to require utilities to contract with QFs in its interconnection queue because the Commission cannot make general management decisions for the utility. *Id*., pp. 11-12. ABATE notes that, in Case No. U-18231, the Commission found Consumers' REP to be reasonable and prudent, except for the new 100 MW of solar.

ABATE also urges the Commission to endorse competitive bidding as the preferred method to set avoided costs rates and procure future capacity. *Id*., p. 13. This bidding plan and capacity procurement structure will, according to ABATE, drive down capacity and energy prices and facilitate transmission planning. *Id*., p. 14. This competitive bidding proposal satisfies Section 6t's requirement that the Commission consider "competitive pricing" in determining if the plan is the most reasonable and prudent means of meeting energy and capacity needs. *Id*.

Last, ABATE addresses SEIA's criticism of the settlement agreement's FCM. Like other parties, ABATE explains that the Commission should reject Mr. Lucas' testimony or give it little weight because his testimony concerned the originally-filed FCM proposed in the utility's IRP and not the FCM included in the settlement agreement. Further, ABATE reiterates that the settlement agreement FCM will ensure that the additional cost of any third-party PPAs are reflected in the competitive solicitation process. *Id*., p. 16. Although ABATE recognizes that customer groups oppose allowing a utility to earn a return on an expense, ABATE continues that, if earning a reasonable return on new PPAs results in Consumers foregoing the construction of more costly new capacity, ratepayers win. ABATE contends that the Commission should find that the settlement agreement is in the public interest, complies with Rule 431, and should approve it. *Id*., p. 17.

D. Staff

The Staff responds to SEIA's arguments about the settlement agreement's failure to resolve the PURPA rights of existing QFs in Consumers' interconnection queue by pointing out that the Commission's October 5, 2018 order in Case No. U-18090 did not determine whether Consumers has an obligation to purchase capacity in its interconnection queue. The Staff notes that the Commission has not yet defined an LEO or said when it begins. Staff's settlement reply brief, p. 5. In addition, the Staff explains that a utility's obligation to purchase power from a QF is a fact-intensive inquiry that requires consideration of the company's capacity need and the price it is paying. *Id.*, p. 7. The Staff repeats its position that the evidence needed to make fact-specific determinations for each QF project in Consumers' interconnection queue is missing in this case and that this matter should therefore be resolved in another forum. *Id*., p. 8. The Staff considered case law that SEIA relies on and points out that SEIA's cited case law shows LEO determinations often depend on the facts of the case. The Staff further asserts that the settlement agreement as a whole is consistent with PURPA and PURPA regulations and preserves the rights of parties to address PURPA issues in other forums. *Id*. The Staff states that SEIA's alternative proposal that resolves outstanding PURPA queue issues "should not be used to derail the settlement in this case." *Id*., p. 11.

Moreover, the Staff contends that SEIA has not demonstrated that its members are harmed by the settlement agreement because the settlement agreement preserves their right to pursue individual complaints in other cases. The Staff suggests that the competitive solicitation process benefits solar developers more than it hurts them, by opening the market to more competition. Further, according to the Staff, SEIA lacks a property interest that is a vested right, which the Staff claims is required to be afforded due process. Instead, the Staff maintains that SEIA merely has a

speculative competitive interest rather than a vested right. The Staff continues that whether QFs have vested rights in projects they have started varies from case to case and urges the Commission to wait until it has more information before deciding whether QFs have vested rights in projects they have started. *Id*., p. 14.

Regarding future Commission review of the settlement agreement's FCM, the Staff agrees with ELPC *et al*. that the FCM is more of a pilot, and that the Commission has the statutory authority to discontinue the FCM for new contracts in Consumers' next IRP case. With respect to SEIA's proposed changes to the competitive solicitation guidelines, the Staff agrees that SEIA's seven suggestions merit review and recommends that, if the Commission approves of the settlement agreement, the stakeholder process provided for in the settlement agreement should serve as the opportunity to consider SEIA's proposed changes to the Case No. U-15800 guidelines. *Id*., p. 16. Finally, the Staff asserts that the settlement agreement's terms provide for reasonable contract terms for QFs entitled to the MISO PRA capacity rate and one of two energy rate options. *Id*.

E. Michigan Environmental Council/Natural Resources Defense Council/Sierra Club

MEC/NRDC/SC repeat their positions and arguments presented in its initial settlement brief, noting their view that the settlement agreement is in the public interest, represents a fair and reasonable resolution of the proceeding, is supported by substantial evidence on the whole record, and should be approved. MEC/NRDC/SC enumerate the ways in which the settlement agreement improves upon Consumers' original PCA and how the settlement agreement furthers the public interest. Turning to SEIA's objection to the settlement agreement that it leaves PURPA interconnection queue issues unresolved, MEC/NRDC/SC point out that the settlement agreement requires Consumers to renew contracts with existing QFs. And, the settlement agreement PCA

includes the Commission-directed 150 MW of PPAs from the Commission's past orders in Case No. U-18090. MEC/NRDC/SC's settlement reply brief, pp. 5-6, referencing the Commission's February 22, 2018 order and October 5, 2018 order in Case No. U-18090.

MEC/NRDC/SC agree with SEIA that the Commission indicated, when it granted Consumers' appeal of a motion to strike testimony regarding PURPA, that PURPA issues are integral to the Commission's required determinations under Section 6t and should be addressed in this IRP proceeding. Nevertheless, MEC/NRDC/SC clarify that these statements were not about the status of QF projects in the queue. *Id*., p. 7. Instead, MEC/NRDC/SC explain, the PURPA issues that the Commission found integral to this case concerned the implementation of PURPA going forward. *Id*. MEC/NRDC/SC observe that issues regarding projects in the queue were not a subject of the motion to strike, and therefore, the Commission made no determination that resolving the status of QF projects in the queue is integral to resolving this IRP case. MEC/NRDC/SC additionally note that the rights of all QF projects in the queue can be decided in other proceedings as provided in the settlement agreement. MEC/NRDC/SC also agree with the Staff's testimony that other determinations, such as defining an LEO and explaining how to manage queue projects, are necessary before the queue can be addressed. Regarding SEIA's proposal for the 800 MW of additional PURPA contracts, MEC/NRDC/SC contend that SEIA has no authority to bind its individual members and that the proposal will not resolve the issue. MEC/NRDC/SC argue that the settlement agreement is reasonable, but also concur with ELPC *et al*. and solar advocates in this case that the Commission should address the existing PURPA queue expeditiously outside of this contested settlement proceeding.

Regarding SEIA's argument that Consumers has a capacity need, MEC/NRDC/SC rely on the initial settlement briefs of Consumers and the Staff, which they contend "convincingly rebutted

SEIA's arguments based on record evidence." *Id.*, p. 9. Regarding SEIA's criticisms of the settlement agreement's FCM, MEC/NRDC/SC stand on the arguments they made in their initial settlement brief. MEC/NRDC/SC repeat that the FCM is authorized by statute, provides an incentive for a regulated utility to retire dirty fossil-fueled plants, and has been substantially reduced from Consumers' initial proposal. MEC/NRDC/SC consider the FCM to be a reasonable compromise that balances competing interests.

In response to SEIA's concerns about the significance of paragraph 11 of the settlement agreement and its potential to bind future Commissions, MEC/NRDC/SC explain that paragraph 11 was added at its request, does not purport to bind the Commission, and simply prohibits Consumers from reopening the settlement agreement if the utility receives an adverse ruling in a future PURPA case that reduces the value of this settlement to Consumers. *Id*., p. 11. MEC/NRDC/SC further discredit SEIA's warning about Consumers potentially overprocuring 6,500 MW of capacity through competitive bidding in addition to the full suite of QF projects in the interconnection queue, noting that the ramp-up of 6,500 MW of capacity will occur over a long timespan and that the settlement agreement will be reopened in the next IRP case to be filed two years from now. *Id*. MEC/NRDC/SC additionally observe that Consumers has alluded to the fact that it can modulate the PCA to address however much capacity comes online from PURPA QFs. Last, MEC/NRDC/SC disagree with SEIA that the public interest was not adequately represented by the parties to the settlement agreement. *Id*., p. 12.

V. Discussion

The Commission finds that the contested settlement agreement at issue here should be approved. The settlement agreement represents a significant change to the traditional utility

business model and transitions the utility and its customers from fossil-fuel based generation to a mix of cost-effective demand-side resources and competitively-bid renewable energy.

Pursuant to Rule 431(5)(a)-(c), Commission approval of a contested settlement agreement is appropriate where the Commission determines: (1) that the objecting parties have been given a reasonable opportunity to present evidence and arguments in opposition to the settlement agreement, (2) the public interest is adequately represented by the parties who entered into the settlement agreement, (3) the settlement agreement is in the public interest, (4) it represents a fair and reasonable resolution of the proceeding, and (5) it is supported by substantial evidence on the record as a whole.

The Commission finds that all of these requirements have been met.[9] Regarding the first requirement, the Commission has provided a reasonable opportunity to those parties that did not sign the settlement agreement to present evidence and argument in opposition to the settlement agreement. Several of the parties submitted direct and rebuttal testimony, filed initial and reply briefs, and appeared at an evidentiary hearing regarding the contested settlement agreement.

With respect to the second criterion, the Commission finds that the parties who entered into the settlement agreement adequately represent the public interest. SEIA argues in this contested

[9] Many of the parties that filed briefs regarding the settlement agreement raise the issue of whether SEIA adequately established that its members would be harmed by Commission approval of the settlement agreement. Although the Commission is aware that Rule 431(3) requires an objecting party to state its objections with particularity and to specify how it would be adversely affected by the settlement agreement, the Commission does not believe this issue is dispositive under the circumstances presented here. To begin, SEIA did file objections that were sufficiently detailed so as to provide the Commission with enough information to allow for consideration of those objections. Likewise, SEIA specified why it believes the settlement agreement would adversely affect its members. For those reasons, the Commission believes that the requirements of Rule 431(3) were met. Yet, merely establishing potential harm is only the first step. The more relevant inquiry is whether the criteria set forth in Rule 431(5)(a) through (c) were met so that the Commission may approve the settlement agreement. The Commission finds that they were.

settlement proceeding that a settlement agreement that both: (1) makes specific determinations regarding PURPA issues that will affect solar QF developers, and (2) has no solar QF represented as a signatory, cannot be deemed to adequately represent the public interest. The Commission disagrees. The signatories to the settlement agreement represent a broad cross section of interests and include the utility and the Staff, as well as environmental organizations, QFs, an association that represents commercial and industrial interests, and the Attorney General, who is charged with representing Michigan ratepayers. The Commission also notes that the Michigan Court of Appeals has, in the past, affirmed a Commission determination that the public interest was adequately represented by the Staff when the Staff was party to a contested settlement agreement. *Attorney General v Mich Pub Serv Comm*, 237 Mich App 82, 93-94; 602 NW2d 225 (1999). Accordingly, the Commission finds that those who signed the settlement agreement adequately represent the public interest.

In addition, the Commission believes that the settlement agreement is in the public interest. The Commission finds persuasive the testimony and arguments of Consumers and others that the settlement agreement was the result of ongoing arms-length negotiations that resulted in significant compromises by all involved. This is evident when comparing the details of Consumers' initial IRP filing with the terms of the proposed settlement agreement. The various compromises reached in this settlement agreement that the Commission views to be in the public interest include all of the following:

- An agreement that Consumers retire Karn 1 and 2 in 2023, which will result in significant savings to ratepayers, reduces pollution, and advances the utility's clean energy goals and the public's interest in clean and reliable energy.

- An agreement that provides potential customer savings by Consumers agreeing to seek recovery of the unrecovered book value and decommissioning costs of Karn 1 and 2 through low-cost debt financing in a separate proceeding, rather than continued recovery through traditional ratemaking which includes a return on these assets.
- An agreement to continue to evaluate the cost-effectiveness of existing coal plants by requiring Consumers to conduct a retirement analysis of Campbell 1 and 2 in its next IRP that will use several assumptions set forth in the settlement agreement, as well as an agreement that, based on the results of this forthcoming analysis, Consumers may retire those units in 2025 or earlier, much sooner than the four-year lag time that the utility originally deemed necessary in order to retire them.
- An agreement that includes $29,952,957 in identified capital costs for expanded DR and CVR programs over the next three years, limits risk to ratepayers by not preapproving O&M costs associated with Consumers' CVR, DR, and EWR programs, and further provides that the capital costs associated with these resources will be subject to annual reporting requirements, and requires Consumers to conduct additional studies to determine best practices regarding the amount of reserves that could be provided by DR and to assess the potential changes in the frequency or duration of curtailments and the role of DR in meeting peak demand.
- A significantly-reduced and transparent FCM on PPA payments that complies with Section 6t(15) and removes the disincentive for Consumers to enter into long-term PPAs with third parties, including renewal of long-term PPAs with existing QFs.

- An agreement that Consumers will use annual competitive solicitations for future capacity additions, hold a stakeholder process to develop competitive solicitation best practices, use an independent evaluator during the process, inform all bidders of the evaluation criteria and process, follow RFP parameters that the Commission approved in Case No. U-15800, timely issue an RFP through public notice, include the terms of the contract in the RFP, use these solicitations to set future PURPA avoided cost rates, and contract with PURPA QFs for any capacity need not filled by an RFP.
- An agreement that Consumers will utilize a 50/50 capacity procurement structure whereby Consumers may own up to a maximum of 50% of all future capacity additions procured through competitive solicitations and must purchase the remaining 50% of its future capacity need through PPAs with third parties that exclude Consumers' affiliates. The Commission finds persuasive the Staff's testimony and arguments that this structure, and the competitive solicitation process Consumers agrees to adhere to, should drive prices down and will also result in the benefit of coordinated generation, distribution, and transmission planning.
- An agreement that Consumers will employ a five-year planning horizon when determining whether the company requires additional capacity, which aligns well with the IRP filing requirements in Section 6t(20) and allows the utility to better adjust to market conditions in arranging its energy resource portfolio.

SEIA disagrees with the conclusion that the settlement agreement is in the public interest and represents a reasonable resolution of the proceeding. Specifically, SEIA argues that the settlement agreement: (1) does not resolve the PURPA rights of existing QFs in Consumers' interconnection

queue, (2) incorrectly concludes that there is no capacity need, (3) proposes an FCM that is unnecessary and unreasonable, (4) includes a competitive bidding process that is less than fair and transparent, (5) provides for a 50/50 capacity procurement approach that will result in increased costs to ratepayers, and (6) results in reduced PURPA PPA contract lengths and a capacity planning horizon that are detrimental to SEIA's members. Each of these concerns are addressed in turn.

1. PURPA Rights of Existing QF Projects in Consumers' Interconnection Queue

SEIA claims that the settlement agreement does not address the rights of existing QFs in Consumers' interconnection queue. That, of course, is not the purpose of an IRP, which is to provide a plan to meet the utility's "5-year, 10-year, and 15-year . . . load obligations, to meet the utility's requirements to provide generation reliability, . . . and to meet all applicable state and federal reliability and environmental regulations over the ensuing term of the plan." MCL 460.6t(3). In addition, the Commission finds compelling Consumers' arguments that the evidentiary record in this proceeding is insufficient to permit the Commission to consider the PURPA rights of any or all QFs in this proceeding. Further, the Commission is persuaded by the arguments of Consumers, ABATE, and the Staff that these outstanding issues should be resolved in other proceedings.

To that end, the Commission agrees with several of the parties participating in the contested settlement agreement that the PURPA rights of QF projects in the interconnection queue are preserved by the language of the settlement agreement. Paragraph 12 of the settlement agreement provides, "This Settlement Agreement is not intended to affect or waive, nor should it be construed as affecting or waiving, the PURPA rights or positions of any party existing prior to

approval by the Commission." The Commission believes that this provision adequately protects the rights of QFs to use other forums to resolve matters related to Consumers' interconnection queue.

Moreover, the Commission finds persuasive MEC/NRDC/SC's discussion in its reply brief regarding the limited scope of certain Commission directives in this case. SEIA argued that the existing interconnection queue issues must be resolved in this proceeding because the Commission, in granting Consumers' appeal of a motion to strike, called various PURPA issues "integral" to its required IRP determinations and directed that these issues be addressed in the IRP. As MEC/NRDC/SC points out, the PURPA issues that the Commission was referring to did not include resolving the matter of the PURPA rights of existing QFs in Consumers' interconnection queue. Rather, the motion to strike related to testimony that discussed the PURPA avoided cost methodology, requests to change the size of QFs eligible for the Standard Offer tariff, the term length of the Standard Offer tariff, and the length of the PURPA capacity planning horizon. Accordingly, the Commission did not intend for its past directive to include PURPA issues in this case to also include the unresolved matter of existing QF projects in Consumers' interconnection queue.[10] In addition, the Commission also agrees with MEC/NRDC/SC that the settlement agreement PCA includes the Commission-directed 150 MW of capacity supplied from PURPA QFs that originated from the Commission's February 22, 2018 order in Case No. U-18090. *See*, Consumers' Exhibit A-2, p. 89. In summary, because such

[10] The Commission concludes that, even if it were possible to resolve these complex, fact-intensive matters regarding the existence of an LEO for QFs currently in Consumers' interconnection queue in this case, it would violate Michigan's Administrative Procedures Act of 1969, 1969 PA 306; MCL 24.201 *et seq*. (APA), to do so based on the evidentiary record in this case. The APA provides that the Commission's decisions must be supported by competent, material, and substantial evidence on the whole record. MCL 24.285. Here, the evidentiary record developed in this case does not support a determination of these issues.

issues are outside the parameters of an IRP, because the Commission is unable to decide LEO matters in this case based on the record before it, and because the Commission agrees with the parties to the settlement that such issues should be addressed in other forums outside of this IRP proceeding, the Commission finds SEIA's concern lacks merit.

In this contested settlement proceeding, SEIA requests that the Commission make its approval of the settlement agreement contingent on inclusion of SEIA's proposal that requires Consumers to purchase 800 MW of capacity from existing QFs in the interconnection queue. The Commission agrees with Consumers that SEIA's proposal is outside the scope of this contested settlement agreement. The issue to be decided in this case is whether the criteria set forth in Rule 431(5)(a) through (c) have been satisfied so that the Commission may approve of the settlement agreement at issue here. Other proposed versions of settlements not adopted by the parties who signed the settlement agreement are not properly before the Commission. Further, the Commission agrees with the Staff that SEIA's proposal should not be used to derail the settlement agreement in this case. Accordingly, the Commission rejects SEIA's recommendation to make approval of the settlement agreement contingent on SEIA's proposal.

2. Capacity Need

With respect to SEIA's argument that the settlement agreement incorrectly provides that there is no capacity need, the Commission disagrees that a capacity need exists upon approval of the PCA as amended by the settlement agreement. The Commission finds that both the Staff and Consumers presented persuasive evidence refuting SEIA's assertions that the utility has a capacity need. The Commission relies on the testimony of Mr. Blumenstock that removal of the capacity provided by the T.E.S. Filer City plant will not result in a capacity shortfall until 2031 and 2032 and, by then, it would be a small shortfall that may never materialize. 10 Tr 3051.

The Commission also agrees with Mr. Blumenstock's testimony that the 56 ZRCs associated with the CVR in Consumers' PCA is part of the settlement agreement that the Commission is approving in this order. 10 Tr 3052. The Commission notes that, in paragraph 2 of the settlement agreement, the parties agree to approval of the capacity value provided by CVR. In that same paragraph, Consumers is required to file an annual reporting template with the Commission that addresses the implementation of the approved DR, CVR, and EWR resources. Also, in that same paragraph, the parties agree that Consumers shall communicate any significant changes or anticipated changes to the expected cost, timing, or size of these resource additions to the Staff. The Commission further agrees with Mr. Blumenstock that the ALJ's recommendation that the Commission reject Consumers' proposal to rely on CVR is not binding on the Commission and is not grounds for rejecting the settlement agreement. *Id*., p. 3053. The Commission finds that there is substantial evidence to support the CVR as proposed in the settlement agreement. *Id*.

The Commission also notes that, under paragraph 7(i) of the settlement agreement, the parties agree that Consumers has no PURPA capacity need so long as the utility is implementing the Commission-approved PCA, including use of the competitive bidding process for all future capacity needs. Because of this language in the settlement agreement, the Commission finds that the 100 MW of solar that SEIA claims is another capacity shortfall will be competitively bid, and as such, will be part of the resources used to meet Consumers' capacity needs. Accordingly, pursuant to the terms of the settlement agreement, the testimony, and the arguments presented in this case, the Commission concludes that there is no capacity need upon approval of the PCA as amended by the settlement agreement. The Commission further notes that it will be reviewing Consumers' capacity need during the next IRP filing and that the PCA provides Consumers with some flexibility to address issues such as capacity need if and when they should arise.

3. FCM

Turning to the settlement agreement's FCM, the Commission finds that the proposed FCM provided for in the settlement agreement is in the public interest. The Commission finds compelling IPPC's arguments about why it supports an FCM in this case and why it signed the settlement agreement. The Commission is persuaded that, even when the law requires Consumers to enter into contracts with PURPA QFs, this may not happen seamlessly or without delay absent an incentive that compensates the utility for the costs of contracting with third parties for capacity through PPAs. IPPC explained that its members have experienced this hesitancy firsthand.

In addition, the Commission is persuaded by the testimony and arguments from the Staff, Consumers, ABATE, and MEC/NRDC/SC demonstrating that a reasonable FCM can safeguard Consumers' credit rating, address risk, and also benefit the public by making the competitive solicitation process and capacity procurement structure a certainty. Specifically, Mr. Maddipati explains how the settlement agreement's FCM incentivizes the policy objectives that Mr. Torrey outlined and corrects for certain financial impacts that Mr. Maddipati outlined in his direct testimony. 7 Tr 735; 10 Tr 3095. Staff witness Paul Proudfoot concluded that, without such an incentive, it may be difficult to expect Consumers to enter into thousands of megawatts of PPAs for solar resources in part because the utility has little opportunity to earn a return on those PPAs. 9 Tr 2365. ABATE witness Jeffry Pollock testified that an FCM can remove any incentive for a utility to prefer a self-build project over a lower-cost PPA and can compensate the utility to reflect the additional credit risk. 7 Tr 2137. And MEC/NRDC/SC's witness Douglas Jester testified that there are costs associated with PPAs that reduce growth in the company's rate base and its earnings and dividends, diminishing the utility's total equity, which can result in current shareholders losing an opportunity for increased share value as a result of the PPA. 8 Tr 1799-

1800; 10 Tr 3096. Therefore, Mr. Jester explained that it makes sense to provide an incentive to increase the use of PPAs to meet a company's capacity and energy needs. *Id*. The Commission further notes that permitting Consumers to earn a reasonable FCM on PPAs is a core element in the competitive solicitation process and capacity procurement approach in this settlement agreement, and which represents a significant change to the utility's business model. Further, MEC/NRDC/SC notes that Section 6t(15) specifically authorizes the Commission to consider such an incentive and that the FCM complies with the limits of this statutory provision as it does not exceed Consumers' WACC. And, ELPC *et al*. points out, and the Staff agrees, that the FCM is subject to Commission review in 2021 and that, if Consumers cannot show that the FCM reduces costs for Michigan customers, the Commission has the authority to discontinue the FCM for new contracts in Consumers' next IRP case. The Commission finds all of these points persuasive. Accordingly, the Commission concludes that the FCM provided for in the settlement agreement is necessary, reasonable, and in the public interest.

4. Capacity Procurement Approach

Regarding SEIA's criticism that the 50/50 capacity procurement approach presented in the settlement agreement will increase costs to Consumers' customers, the Commission agrees with Consumers that this assertion is speculative. The Commission finds persuasive Mr. Troyer's testimony pointing to a 41% reduction in solar resource LCOE between 2017 and 2018 and his assertion that it is reasonable to expect this trend of declining solar costs to continue. 10 Tr 3064. The Commission also finds compelling Mr. Proudfoot's testimony that, with regard to renewable energy cases in the past, competition has driven down costs associated with capacity procurement and that it is likely to do so in this case. 9 Tr 2565. The Commission also notes that Mr. Proudfoot testified about other ancillary benefits of such an approach, including the fact that

allowing Consumers to own a portion of the new resources will give the company greater control over the maintenance and operation of the equipment, greater insight into the performance of the equipment, and better equip the utility to forecast output from solar resources. *Id*. Thus, although the Commission agrees that consideration of this issue is somewhat theoretical in nature given the difficulty in accurately projecting trends showing declining or increasing costs, the Commission further finds that an approach where 50% of new capacity additions must be procured through PPAs that exclude Consumers' affiliates benefits the utility's ratepayers, solar developers, and the environment. Therefore, the Commission concludes that this aspect of the settlement agreement is in the public interest and does not warrant a rejection of the settlement agreement.

5. Competitive Bidding

Regarding SEIA's criticism that the competitive bidding process included in the settlement agreement is not as fair and transparent as it needs to be and could be improved, the Commission has considered SEIA's arguments and finds that they should be rejected. First, the Commission notes that the process is vastly improved because it incorporates the guidelines from Case No. U-15800 and includes a robust stakeholder process that will ensure a transparent and open solicitation process as well as produce uniform standards for such a process. Consumers pointed out that SEIA originally recommended using the guidelines that the Commission approved for RFPs in Case No. U-15800 as a baseline for competitive solicitations. This settlement agreement does just that, by requiring Consumers to use those procedures until the Commission adopts competitive bidding guidelines or procedures as part of a future proceeding.

Although SEIA contends that nothing in the settlement agreement requires the utility to act on the feedback that it receives during the stakeholder process, both the Staff and Consumers disagreed with this interpretation. Paragraph 7(k) of the settlement agreement sets forth a multi-

step stakeholder process that begins with the requirement that Consumers provide its draft competitive bidding guidelines to stakeholders so that they may make recommendations to Consumers. After this process, Consumers must submit its final competitive bidding procedures to stakeholders. Then, by April 1, 2020, Consumers must "commence a second workshop to share information on bids received and selected, the impact of the FCM on PPA bids, the costs and benefits to ratepayers, the role of the independent evaluator, criteria used to rank proposals, and any other criteria deemed important." Interested parties will have an opportunity to discuss this information and ask questions. Consumers and interested parties then have an opportunity to file comments about the reasonableness of the competitive bidding procedures and to recommend changes and additions. The Commission will then issue an order adopting uniform standards on best practices for competitive bidding and RFPs. The Commission will further evaluate the reasonableness of Consumers' bidding procedures in its next IRP. The Commission finds this process to be in the public interest because it allows stakeholders to have input into procedures that will be employed both before and after the first annual solicitation.

The Staff observes that the annual nature of these solicitations ensures the process is evaluating up-to-date cost information for IRP modeling and setting avoided costs. 9 Tr 2721. Further the Staff notes that "[a]nnual solicitations also allow developers that would otherwise ask for PURPA contracts to bid on larger projects allowing for greater economies of scale and interconnection at the transmission level, reducing the complexity and costs of interconnection compared to large PURPA contracts interconnecting at the distribution level." Staff's initial brief, p. 15, citing 9 Tr 2722. Similarly, MEC/NRDC/SC notes that the process allows for annual solicitation of technologies set forth in the PCA , including solar, to be used in the bidding process.

The Commission agrees with the Staff that SEIA's seven additional recommendations regarding ways to improve this process should be considered as part of the stakeholder process associated with this settlement agreement. Moreover, the Commission agrees that the process overall benefits the public and ensures an unbiased, transparent, and open process because it provides for use of an independent evaluator, informs all bidders of the evaluation criteria and process, follows RFP parameters that the Commission approved in Case No. U-15800, requires timely issuance of an RFP through public notice, and requires that the terms of the contract be included in the RFP. With a phased-in process for bidding and opportunities for stakeholder input on bidding criteria and processes, the Commission also expects the public interest to be served as technologies evolve, such as consideration of solar combined with battery storage, in the bidding process.

6. Changes to Implementation of the Public Utility Regulatory Policies Act of 1978

Regarding the five-year capacity planning horizon, the Commission finds this aspect of the settlement agreement to be in the public interest. The Staff argues that this compromise serves the public's interest in administrative efficiency because it aligns this planning horizon with the IRP filing requirements in 6t, which require an IRP to be filed every five years. MEC/NRDC/SC likewise view this compromise to be a fair and reasonable resolution of this issue.

Finally, SEIA criticizes the settlement agreement provision that sets out PURPA contract length options with varying capacity and energy rates available under the Standard Offer or when Consumers does not have a capacity need. The Commission agrees with Consumers that SEIA misstates the provisions of the settlement agreement and further agrees that this issue does not warrant rejecting the settlement agreement. The Commission finds persuasive Consumers' explanation that Mr. Lucas wrongly asserts that the Standard Offer contract term is limited to 10

years. The settlement agreement clearly presents QFs with opportunities to secure PPAs with Consumers for longer periods. Specifically, paragraph 7(h) provides that QFs up to 20 MW in size can participate in the competitive solicitation process for a contract term up to 25 years. And, as Consumers observes, "if the company does not fill capacity in the PCA through the competitive solicitation process, the capacity becomes available to other QFs at the full avoided cost rate with an expected contract term of 25 years." Consumers' initial brief, p. 47. Consumers likewise notes that both Mr. Troyer and Mr. Harlow refuted SEIA's criticisms about the rates and terms available to QFs when Consumers does not have a capacity need. The testimony of these witnesses supported a 5-year contract term for forecasted pricing and a 15-year term for actual pricing in initially filed direct testimony. *See*, 8 Tr 1269-1270; 9 Tr 2721-2722. For these reasons, the Commission finds the proposed PURPA rates and terms and the Standard Offer contract term to be reasonable, in the public interest, and supported by the record.

Having addressed each of SEIA's arguments as to whether the settlement agreement is in the public interest and represents a fair and reasonable resolution of the proceeding, the Commission finds that, for all of the reasons set forth, the settlement agreement is in the public interest. The Commission also finds that the proposed settlement agreement is a fair and reasonable resolution of this proceeding. In addition, having read the record, the Commission likewise finds the settlement agreement to be supported by substantial evidence on the record as a whole. Moreover, as agreed to by the parties in paragraph 1 of the settlement agreement and supported by the record, the Commission finds that Consumers' PCA as amended by the settlement agreement is the most reasonable and prudent means of meeting Consumers' energy and capacity needs over the time horizon of this IRP.

The Commission observes that the terms of the settlement agreement will place Consumers' next IRP before the Commission in June 2021 and the Commission will then have an opportunity to revisit many of these same issues with the benefit of additional analysis and information about the accuracy of past projections. In this way, the settlement agreement adopted today provides an additional measure of flexibility and modularity allowing new information to further inform the utility's long-term plans. It also serves as an important foundation that can be built upon when the Commission revisits the IRP planning process in 2021. The Commission further agrees with the characterization of several parties to the settlement agreement that the settlement agreement is groundbreaking, transforms the way Consumers does business, represents a dramatic departure away from fossil fuel generation towards the use of clean energy, and incorporates a competitive bidding process that will reduce prices for Consumers' customers. With approval of this agreement, Consumers is dramatically departing from the traditional utility approach to resource planning and investment. Customer engagement and participation by third-party energy service providers will be integral to the success of this IRP. The Commission considers the proposed settlement agreement to benefit Consumers' ratepayers, solar developers, the environment, and the company.

Looking ahead to Consumers' filing of its next IRP in 2021, the Commission expects that Consumers will work in close collaboration with METC and will provide METC a thorough and timely retirement analysis of its aging generation units and new resource plans to allow for a more accurate and in-depth analysis of transmission issues in the next IRP. In addition, as many of the elements contained in the PCA as amended by the settlement agreement - including DR, EWR, CVR, and modular solar build - may be sited on the utility's distribution system, the Commission also directs Consumers to explore the possibility of integrating resource and distribution planning

in the next IRP. A holistic review of energy infrastructure options and customer trends, such as adoption of renewable energy, EWR, and electric vehicles, is essential to optimize investments for the benefit of ratepayers.

The Commission has reviewed the settlement agreement and finds that the public interest is adequately represented by the parties who entered into the settlement agreement. The Commission further finds that the settlement agreement is in the public interest, represents a fair and reasonable resolution of the proceeding, is supported by substantial evidence on the whole record, and should be approved.

THEREFORE, IT IS ORDERED that**:**

A. The settlement agreement, attached as Exhibit A, is approved.

B. Unless otherwise provided in the settlement agreement, the terms of the approved settlement agreement shall take effect immediately upon issuance of this order.

C. In accordance with paragraph 7(h) of the settlement agreement, Consumers Energy Company shall file, within 30 days of this order, revised Standard Offer tariff sheets and a revised Standard Offer contract, to reflect the Standard Offer construct and rates approved as part of the approved settlement agreement. Also pursuant to paragraph 7(h), parties shall have 14 calendar days subsequent to these filings to provide comments to the Commission in this docket.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Sally A. Talberg, Chairman

Norman J. Saari, Commissioner

Daniel C. Scripps, Commissioner

By its action of June 7, 2019.

Barbara S. Kunkel, Acting Executive Secretary

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for Approval of an Integrated Resource Plan under MCL 460.6t and for other relief.	)))))	Case No. U-20165

SETTLEMENT AGREEMENT

Pursuant to MCL 24.278 and Rule 431 of the Michigan Administrative Hearing System's Rules of Practice and Procedure before the Michigan Public Service Commission ("MPSC" or the "Commission"), the undersigned parties agree as follows:

WHEREAS, on June 15, 2018 Consumers Energy Company ("Consumers Energy" or the "Company") filed an Application requesting approval of the Company's Integrated Resource Plan ("IRP") pursuant to Section 6t of 2016 PA 341, MCL 460.6t, the Commission's December 20, 2017 and November 21, 2017 Orders in Case Nos. U-15896, et al., and U-18418, respectively, and all other applicable law. The Company filed testimony and exhibits in support of its positions concurrently with its Application.

WHEREAS, the initial prehearing conference in this proceeding was held on July 16, 2018 before Administrative Law Judge Sharon L. Feldman. The Commission Staff ("Staff"); Michigan Environmental Council, the Sierra Club, and the Natural Resources Defense Council (collectively, "MEC"); the Association of Businesses Advocating Tariff Equity ("ABATE"); Energy Michigan, Inc.; Michigan Energy Innovation Business Council and Institute for Energy Innovation ("MEIBC"); the Independent Power Producers Coalition of Michigan ("IPPC"); Solar Energy Industries Association, Inc. ("SEIA"); the Michigan Chemistry Council; Michigan Electric Transmission Company, LLC ("METC"); Cypress Creek Renewables, LLC; Residential

Customer Group ("RCG"); Great Lakes Renewable Energy Association ("GLREA"); Attorney General Dana Nessel ("Attorney General"); Midland Cogeneration Ventures, LP ("MCV"); Environmental Law & Policy Center, The Ecology Center, Union of Concerned Scientists, and Vote Solar (collectively, "ELPC"); and the Biomass Merchant Plants ("BMPs") intervened in this proceeding. 1 TR 10.

WHEREAS, Consumers Energy filed testimony and exhibits requesting approval of the Company's IRP Proposed Course of Action ("PCA") in its entirety, as the most reasonable and prudent means of meeting the Company's energy and capacity needs through 2040. As part of its approval of the PCA, the Company specifically requested the Commission to make the following determinations:

(i) Approve as reasonable and prudent for cost recovery purposes the Company's proposed Energy Waste Reduction ("EWR"), Demand Response ("DR"), and Conservation Voltage Reduction ("CVR") costs which will be commenced by the Company within three years following the Commission's approval of the Company's IRP;

(ii) Approve the Company's proposal to recover the unrecovered book balance of D.E. Karn ("Karn") Units 1 and 2, including decommissioning costs, and proposed regulatory accounting treatment through 2031;

(iii) Approve the Company's proposed competitive-bid methodology for determining avoided costs rates and for determining and addressing the Company's capacity position pursuant to the Public Utility Regulatory Policies Act of 1978 ("PURPA");

(iv) Approve the utilization of a five-year period for the purpose of determining the Company's capacity position and related obligations pursuant to PURPA and find that the Company has no PURPA capacity need so long as the Company is implementing the PCA, as approved by the Commission; and

(v) Approve the Company's Financial Compensation Mechanism ("FCM") for any new Power Purchase Agreements ("PPAs") entered by the Company.

Staff and other intervening parties filed testimony and exhibits addressing various issues.

NOW THEREFORE, for purposes of settlement of Case No. U-20165, the undersigned parties agree as follows:

1. The parties agree that the Company's PCA, as modified herein, should be approved as the most reasonable and prudent means of meeting the Company's energy and capacity needs over the 5-year, 10-year, and 15-year time horizons. Such approval shall mean that the Company's PCA will be evaluated in future IRP proceedings to determine if the PCA continues to represent the most reasonable and prudent means of meeting the Company's energy and capacity needs. The Company will file a new IRP by June 2021.

2. The parties agree that the identified capital costs for DR ($21,028,357) and CVR ($8,924,600) that the Company will incur in the next three years (June 2019 – June 2022) are reasonable and prudent and pre-approved for cost recovery purposes and will be included in rates in a future Company rate case consistent with MCL 460.6t(11) and (17). The parties further agree to the approval of the capacity value provided by the DR (total peak load reduction of 607 MW (incremental 238 MW) from 2019 levels proposed in the Company's pending electric rate case) by June 1, 2022; CVR (a total peak load reduction of 44 MW (incremental 40 MW) by June 1, 2022); and EWR (total EWR peak load reductions of 718 MW (incremental 52 MW from current EWR Plan) by June 1, 2022) resources that the Company will invest in during the next three years. The Company shall file an annual reporting template with the Commission addressing the implementation of the approved DR, CVR, and EWR resources above. The parties further agree that the Company shall communicate any significant changes or anticipated changes to the expected cost, timing, or size of any of the above resource additions to Staff.

3. The parties agree that Karn Units 1 and 2 will be retired in 2023. The Company agrees to seek recovery of the Karn Units 1 and 2 unrecovered book balance by no later than

May 31, 2023, filing an application under the applicable provisions of Customer Choice and Electricity Reliability Act, MCL 460.10 *et seq*., seeking a financing order from the Commission authorizing Consumers Energy to recover the unrecovered book balance of Karn Units 1 and 2.

4. The Parties agree that the Company will conduct a retirement analysis of J.H. Campbell ("Campbell") Units 1 and 2 in the Company's next IRP case, which will be filed in June of 2021 and that analysis shall include the following assumptions:

a. The analysis will evaluate the following potential retirement dates: 2024, 2025, 2026, 2028, and 2031;

b. For each of the potential retirement dates, the analysis will evaluate the retirement of Campbell Unit 1, Campbell Unit 2, and Campbell Units 1 and 2 together;

c. The analysis will (i) provide a detailed explanation for the Company's capital expenditure and major maintenance cost projections for each retirement scenario; (ii) provide a detailed explanation of how the Company's forecasted unit heat rates are consistent with its cost projections; and (iii) apply consistent assumptions to each retirement scenario to address how capital and major maintenance costs change in the years leading up to an assumed retirement date;.

d. The analysis's modeling of potential replacement resources will include, but not be limited to, (i) Michigan wind and out-of-state wind; and (ii) capacity purchases (i.e., bilateral contracts), including MCV, both within and external to Zone 7. For the capacity purchases option, the assumed cost should include the Company's recent bilateral capacity contracts;

e. The analysis will (i) include different capacity price assumptions (0, 25, 50, 75, 100% of cost of new entry), as in the prior retirement analysis; and (ii) also include a capacity price assumption based on the Company's most recent reverse capacity auction;

f. The analysis will determine the potential impact of retiring Campbell Units 1 and 2 on the current Capacity Import Limit ("CIL");

g. The analysis will identify any transmission system improvements (and the estimated costs) associated with retiring Campbell Units 1 and 2 and adding any equivalent replacement capacity; and

h. The analysis will model the potential retirement of Campbell Units 1 and 2 using the Company's gas price forecast in addition to any MPSC-mandated forecast (e.g., the Energy Information Administration's Annual Energy Outlook forecast).

5. If, in the Company's next IRP, the Company proposes to retire Campbell Unit 1 and/or Unit 2 in 2025 or earlier or agrees to a Commission recommendation that the Company should retire Campbell Unit 1 and/or Unit 2 in 2025 or earlier, the Company commits to retiring the unit(s) within three years from the Commission's final order approving the Company's IRP. However, the above addressed three-year retirement window shall be subject to the Midcontinent Independent System Operator, Inc.'s ("MISO") designation of Campbell Unit 1 and/or Unit 2 as a System Support Resource ("SSR"). If MISO makes such an SSR designation, the Company shall operate Campbell Unit 1 and/ or Unit 2 in accordance with MISO's designation and direction. This provision does not preclude any party from advocating for a retirement date for Campbell Unit 1 and/or Unit 2 prior to 2025 or for a shorter retirement window than three years from the Commission's final order approving the Company's IRP.

6. The parties agree that the Company will identify in its intervening rate cases avoidable capital expenditures (environmental and non-environmental) and avoidable major maintenance for Campbell Units 1 and 2 in 2024 and 2025 retirement scenarios. The parties further agree that the terms of this Settlement Agreement do not limit any party's right to advocate for a retirement analysis of Campbell Units 1 and 2 to be provided prior to the Company's next IRP and any party's right to advocate for the retirement of Campbell Units 1 and 2 any time prior to 2031 in other Commission cases and advocacy.

7. The parties agree that a competitive bidding process should be used to address future capacity needs of the Company during the IRP period approved as provided in Paragraph 1 of this Settlement Agreement and also for determining the Company's PURPA avoided cost rates. The Company shall use a five-year outlook for determining capacity needs. The competitive bidding process shall utilize the following parameters:

a. The Company shall conduct annual solicitations for the technology or technologies specified in the PCA;

b. Any remaining capacity that is not filled by responses to each Request for Proposal ("RFP") would be available to Qualifying Facilities which the Company has a legal obligation to purchase from under PURPA (such facilities are referred to as "QFs" in this Settlement Agreement). The QFs would receive a contract with terms substantially similar to the RFP respondents. Specifically, the full avoided cost rate offered will be equal to the highest priced proposal that received a contract in the competitive solicitation and the contract length will be the same as offered in the competitive solicitation. QFs that enter PURPA-based PPAs with the Company pursuant to this provision shall not be required to automatically transfer Renewable Energy Credits ("RECs") to the Company but may sell RECs to the Company at a mutually agreed upon price;

c. The competitive bid process shall be administered by an independent third party. The evaluation criteria and process is to be made available to all bidders submitting responses for the specific technology requested by the Company, as part of the RFP, to ensure transparency. QFs may bid any technology that meets the requirements of PURPA. A ranking of proposals is to be used by the independent third party and provided to the Company for selection. Both the cost of the resource and the value that it provides are to be considered to determine the net cost of a resource to compare different technologies offered by QFs;

d. The Company shall utilize the competitive bidding procedures attached as Attachment A to this Settlement Agreement during the IRP period approved as provided in Paragraph 1 for all future solicitations until such time that the Commission adopts competitive bidding guidelines or procedures as part of a future proceeding. The Company shall also utilize the competitive bidding procedures attached as Attachment A to this Settlement Agreement for all new Company-owned supply-side resources that are developed as part of the PCA approved by the Commission in this case;

e. The first competitive solicitation for the Company pursuant to this Settlement Agreement will be conducted no later than September 30, 2019. New full avoided cost rates stemming from each competitive solicitation will be filed with the Commission for review and approval within 30 days of the conclusion of each competitive solicitation;

f. The maximum term length of competitively bid contracts will be equivalent to the depreciation schedule of a similar Company-owned asset. For solar projects, this is currently 25 years;

g. Current existing QFs with a PURPA-based PPA with the Company, as of January 1, 2019, shall receive new PPAs, regardless of the Company's capacity need, upon the expiration of their current PPAs based on the Company's full avoided cost rates at the time of PPA expiration. QFs that receive a contract based on the Planning Resource Auction ("PRA") rate and forecasted or actual Locational Marginal Prices ("LMPs") shall not automatically receive a contract at the full avoided cost rate when their current contract expires; however, these QFs will be eligible to participate in future competitive solicitations after their contracts expire;

h. The Standard Offer PPA shall be available to QFs up to 2 MW. QFs at or below 150 kW shall receive a PPA based on the Company's full avoided cost rates, regardless of the Company's capacity need, for the maximum term provided for full avoided costs. QFs above 150 kW to 2 MW in size can participate in the competitive bidding process or can receive the MISO PRA capacity rate and either (i) a 10-year term based on a forecast of LMPs for the first five years and year six through year 10 of the term will be equal to the price of energy in the fifth year of the LMP forecast or (ii) actual LMPs for 15 years. Within 30 days following the Commission's approval of this Settlement Agreement, the Company shall file revised Standard Offer tariff sheets and a revised Standard Offer contract, to reflect the Standard Offer construct and rates approved as part of this Settlement Agreement. Parties shall be given 14 calendar days subsequent to the Company's filing to provide comments to the Commission;

i. The Company has no PURPA capacity need so long as the Company is implementing the Commission-approved PCA, as provided in Paragraph 1, including the competitive bidding process for all future capacity needs;

j. When the Company has no capacity need, as defined in Paragraph 7.i. above, QFs are eligible to receive the MISO PRA capacity rate, which will be adjusted annually each MISO Planning Year based on the results of the MISO PRA, and either (i) a 10-year term based on a forecast of LMPs for the first five years and year six through year 10 of the term will be equal to the price of energy in the fifth year of the LMP forecast or (ii) actual LMPs for 15 years. QFs that enter PURPA-based PPAs with the Company pursuant to this

provision shall not be required to automatically transfer Renewable Energy Credits ("RECs") to the Company but may sell RECs to the Company at a mutually agreed upon price; and

k. Subsequent to the issuance of the Commission's order approving this Settlement Agreement and prior to issuance of the first competitive solicitation for the Company pursuant to this Settlement Agreement, the Company shall commence a competitive bidding stakeholder workshop. During this workshop, the Company shall provide draft competitive bidding guidelines to stakeholders so that participating stakeholders can provide recommendations to the Company. After receiving recommendations, the Company shall provide stakeholders with final competitive bidding procedures for the first competitive solicitation to be conducted by September 30, 2019. By April 1, 2020, the Company shall commence a second stakeholder workshop to share, at a minimum, information on bids received and selected, the impact of the FCM on PPA bids, the costs and benefits to ratepayers, the role of the independent evaluator, criteria used to rank proposals, and any other criteria deemed to be important. At the second stakeholder process, interested parties will have an opportunity to discuss the information the Company provides and ask questions. Within 35 calendar days of the second stakeholder process, the Company and interested parties will have an opportunity to file comments about the reasonableness of the Company's competitive bidding procedures and to recommend changes and additions. Parties will then have 21 calendar days to file responses. These comments, recommendations, and responses will be filed in Case No. U-20165 or in another docket that the Commission opens to facilitate this process. Once comments, recommendations, and responses have been filed, the Commission will have an opportunity to consider all interested parties' input and to issue an order adopting uniform standards on best practices for competitive bidding and RFPs. The reasonableness of the Company's competitive bidding procedures shall also be evaluated in the Company's next IRP. This evaluation shall include at least information on bids received and selected, impact of the FCM on PPA bids, costs to ratepayers, role of the independent evaluator, criteria used to rank proposals, and any other criteria deemed to be important.

8. The parties agree that the new capacity that the Company intends to procure through the PCA, in each annual solicitation, shall be: (i) acquired through a competitive bidding process; and (ii) 50% will be from PPAs and 50% will be owned by the Company, as acquired through a competitive bidding process. The Company, at its sole discretion, may choose to acquire more than 50% of its new capacity from PPAs. The parties further agree that

the Company's affiliates will be prohibited from bidding on the portion of the Company's new capacity acquired from PPAs.

9. The parties agree that the Company shall receive, and recover in general electric rates an FCM on all new PPAs approved by the Commission on or after January 1, 2019, including PURPA contracts. The method of cost recovery shall be determined in the Company's next rate case. However, the Company shall not receive an FCM on any PPAs executed under the Company's Renewable Energy Plan. For PPAs subject to the FCM, the Company will be authorized to annually earn an FCM equal to the product of PPA payments in that year multiplied by the Weighted Average Cost of Capital ("WACC"), which is currently 5.88%, of the Company's total capital structure at the time of PPA execution, for the entire term of the contract. The FCM shall not exceed the WACC of the Company's total capital structure multiplied by the schedule of MWh prices in Attachment B to this Settlement Agreement based on the time of PPA execution. The parties agree that the Commission has the authority to consider the existence of an FCM in determining the overall cost of capital, including the appropriate capital structure and cost of equity, as it relates to imputed debt. The parties further agree that the amount of the FCM could be reviewed in future IRP proceedings and adjusted if circumstances warrant the adjustment and the Commission may consider the FCM in rate cases when reviewing issues related to imputed debt. However, such an adjustment would not impact the FCM approved as part of any existing PPAs. The parties agree that during the competitive bidding process addressed in Paragraph 7 of this Agreement, the Company shall provide bidding parties with information necessary to calculate the price impact of the FCM on a submitted bid.

10. The Company acknowledges that capacity imports can lend support to the Company's PCA and that opportunities to increase the CIL should be evaluated. In addition, the

Company acknowledges that the CIL supports the reliability of the transmission system and that an adequate CIL needs to be maintained. The Company shall continue to collaborate with METC and MISO on the implementation of the PCA to minimize negative impacts on the Zone 7 CIL and investigate opportunities to increase the CIL. The Company also agrees to continued collaboration with METC on the implementation of all future PCAs.

11. If the Commission issues future PURPA-related orders in other proceedings, the impact of those orders on the Company's PCA, as approved pursuant to this Settlement Agreement, will be addressed in future proceedings, including the Company's next IRP, and will not be a basis for re-opening this Settlement Agreement.

12. This Settlement Agreement is not intended to affect or waive, nor should it be construed as affecting or waiving, the PURPA rights or positions of any party existing prior to approval by the Commission.

13. The parties agree that the Company's next IRP shall include:

a. Modeling of in-state and out-of-state wind;

b. A stochastic risk assessment;

c. Modeling of all optimized portfolios in all scenarios as part of the Risk Assessment Methodology;

d. Continued collaboration with METC and MISO on the implementation of the PCA including: (i) an analysis of the PCA's impact on the Zone 7 CIL; and (ii) an analysis of minimizing the impact on the Zone 7 CIL as well as investigating opportunities to increase the CIL and investigating transmission alternatives to improve market access;

e. Utilization of other mediums of communication to educate and collect feedback from interested stakeholders of the public;

f. Modeling of energy storage and solar resources either in isolation or as a combination and continued investigation into energy storage to potentially incorporate into future IRP modeling;

g. A list of all environmental regulations applicable to the utility fleet;

h. A description, to the extent practicable, of how a Michigan workforce will be utilized in the construction or investment in a new or existing capacity resource in this state;

i. Consideration of a distributed generation program, similar to Staff's Customer Distributed Generation Program proposed by Staff witness Meredith A. Hadala in this case;

j. A description of the demand for participation in customer-initiated renewable energy resources that are satisfying the Company's demand. The Company shall consider including the forecast dependent on actual data and trending;

k. A description of the transportation electrification and heating electrification impacts of the Company's demand forecast. The Company shall consider including the forecast dependent upon actual data and trending;

l. A survey of current DR practices of other electric utilities, particularly an analysis of planning assumptions; whether limits are imposed on the amount of reserves that can be provided by DR; and quantifying the amount of DR as a percent of peak demand. The Company shall meet with representatives from ABATE to discuss the results of these studies prior to the filing of the Company's next IRP;

m. Results of a loss of load expectation study to assess the potential change in either the frequency or durations of curtailments and the role of DR in meeting peak demand. The study should reflect the impact of varying generation capacity mix scenarios, including the PCA and varying amounts of DR. The Company shall also monitor changing requirements for load modifying resources at MISO;

n. An assessment of ways to reduce excess capacity which may exist in the resource plan approved as part of this Settlement Agreement;

o. An assessment showing how the Company intends to meet peak demand during winter months with its resource portfolio in each of the projected plan years; and

p. An assessment of the impact of the FCM on the competitive bidding process.

14. This settlement is entered into for the sole and express purpose of reaching a compromise among the parties. All offers of settlement and discussions relating to this settlement are, and shall be considered, privileged under MRE 408. If the Commission approves

this Settlement Agreement without modification, neither the parties to this Settlement Agreement nor the Commission shall make any reference to, or use, this Settlement Agreement or the order approving it, as a reason, authority, rationale, or example for taking any action or position or making any subsequent decision in any other case or proceeding; provided, however, such references may be made to enforce or implement the provisions of this Settlement Agreement and the order approving it.

15. This Settlement Agreement is based on the facts and circumstances of this case and is intended for the final disposition of Case No. U-20165. So long as the Commission approves this Settlement Agreement without any modification, the parties agree not to appeal, challenge, or otherwise contest the Commission order approving this Settlement Agreement. Except as otherwise set forth herein, the parties agree and understand that this Settlement Agreement does not limit any party's right to take new and/or different positions on similar issues in other administrative proceedings, or appeals related thereto.

16. This Settlement Agreement is not severable. Each provision of the Settlement Agreement is dependent upon all other provisions of this Settlement Agreement. Failure to comply with any provision of this Settlement Agreement constitutes failure to comply with the entire Settlement Agreement. If the Commission rejects or modifies this Settlement Agreement or any provision of the Settlement Agreement, this Settlement Agreement shall be deemed to be withdrawn, shall not constitute any part of the record in this proceeding or be used for any other purpose, and shall be without prejudice to the pre-negotiation positions of the parties.

17. The parties agree that approval of this Settlement Agreement by the Commission would be reasonable and in the public interest.

18. The parties agree to waive Section 81 of the Administrative Procedures Act of 1969 (MCL 24.281), as it applies to the issues resolved in this Settlement Agreement, if the Commission approves this Settlement Agreement without modification.

WHEREFORE, the undersigned parties respectfully request the Commission to approve this Settlement Agreement on an expeditious basis and to make it effective in accordance with its terms by final order.

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

By: Spencer Sattler Digitally signed by Spencer Sattler Date: 2019.03.23 15:24:37 -04'00' Date: March 23, 2019

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NATURAL RESOURCES DEFENSE COUNCIL

By: _____ Date: 03/22/2019

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SIERRA CLUB

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ATTORNEY GENERAL DANA NESSEL

By: Celeste R. Gill Digitally signed by Celeste R. Gill Date: 2019.03.22 16:14:39 -04'00'

Date: March 22, 2019

Celeste R. Gill, Esq.
Assistant Attorney General
Special Litigation Division
6th Floor Williams Building
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Post Office Box 30755
Lansing, MI 48909

MICHIGAN ELECTRIC TRANSMISSION COMPANY

By: Richard J. Aaron/ With Permission MKH

Date: March 22, 2019

Richard J. Aaron, Esq.
Dykema Gossett PLLC
201 Townsend Street, Suite 900
Lansing, MI 48933

The following parties do not wish to be signatories to this Settlement Agreement; however they have agreed to sign below to indicate non-objection to the Settlement Agreement:

ENVIRONMENTAL LAW AND POLICY CENTER, THE ECOLOGY CENTER, UNION OF CONCERNED SCIENTISTS, VOTE SOLAR

By: _____ Date: March 23, 2019

Margrethe Kearney, Esq.
Environmental Law & Policy Center
1514 Wealthy Street SE, Suite 256
Grand Rapids, MI 49506

The following parties do not wish to be signatories to this Settlement Agreement; however they have agreed to sign below only to indicate non-objection to the Settlement Agreement:

MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL AND INSTITUTE FOR ENERGY INNOVATION

By: Laura A. Chappelle

Date: March 22, 2019

Laura A. Chappelle, Esq.
Varnum, LLP
The Victor Center, Suite 910
201 North Washington Square
Lansing, MI 48933

ATTACHMENT A

Attachment A

The Parties agree that the following guidelines are intended to shape the competitive bidding process for Consumers Energy Company's ("Consumers Energy") Integrated Resource Plan ("IRP"). The guidelines are not intended to be a comprehensive methodology.

- To the extent applicable, Consumers Energy shall use the RFP parameters included in the 2008 *Guidelines for Competitive Request for Proposal for Renewable and Advanced Cleaner Energy*, as adopted in Attachment D of the Commission's December 4, 2008 Temporary Order in Case No. U-15800.

- Timely Issuance of RFP through Public Notice: The issuance of an RFP will be made through public notice to ensure parties interested in responding have an opportunity to learn of it.

- Terms of Contract Provided in RFP: In accordance with MCL 460.6t(6), Consumers Energy shall provide the terms of the contract in their RFP. Consumers Energy may accomplish this by developing standard form contracts along with credit terms and instruments to be included in the RFP.

- Independent Evaluator ("IE"): In the implementation of the Company's Proposed Course of Action, the Company will utilize an IE during the competitive solicitation of Power Purchase Agreements and the generating facilities that the Company may ultimately own, in the manner proposed by Company witness Keith G. Troyer at 8 TR 1285-1289 and Exhibit A-107 (KGT-4).

ATTACHMENT B

Contract Year	Total Rate ($/MWh)
2019	**55.54**
2020	**57.49**
2021	**59.38**
2022	**61.28**
2023	**63.25**
2024	**65.24**
2025	**67.24**

P R O O F O F S E R V I C E

STATE OF MICHIGAN)

Case No. U-20165

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on June 7, 2019 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna Brown

Subscribed and sworn to before me
this 7th day of June 2019.

Angela P. Sanderson

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2024

Service List for Case: U-20165

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Appendix E: November 18, 2021 Order in Case No. U-20165 –
Consumers Energy Ex-Parte Contract Approval

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.	)))))	Case No. U-20165

At the November 18, 2021 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Tremaine L. Phillips, Commissioner
Hon. Katherine L. Peretick, Commissioner

ORDER

On October 14, 2021, Consumers Energy Company (Consumers) filed an application (October 14 application) with supporting testimony and exhibits, requesting *ex parte* approval of a build transfer agreement (BTA) with Washtenaw Solar Energy, LLC (Washtenaw Solar). The company also sought a Commission determination that the BTA was reasonably and prudently selected in accordance with the company's integrated resource plan (IRP) settlement agreement, as approved in the June 7, 2019 order in Case No. U-20165 (June 7 order). October 14 application, p. 1.

Additionally, on October 19, 2021, Consumers filed an application in the instant docket (October 19 application) with supporting testimony and exhibits, pursuant to Section 6j of Public Act 304 of 1982, MCL 460.6j, requesting *ex parte* approval of two power purchase agreements (PPAs); one with Cereal City Solar, LLC (Cereal City Solar) for the output of the Cereal City

Solar Project and another with Jackson County Solar, LLC (Jackson County Solar) for the output of the Jackson County Solar Project. October 19 application, p. 1.

By way of providing background, Consumers explains in the October 19 application that on June 15, 2018, Consumers filed its IRP in Case No. U-20165, which included the company's commitment to procure approximately 6,000 megawatts (MW) of new solar resources by 2040. The Commission approved a settlement agreement for the IRP in the June 7 order. Included in the settlement agreement was the company's agreement to utilize an annual competitive solicitation process to acquire technologies specified in the IRP's proposed course of action (PCA). Consumers' second request for proposal (RFP) pursuant to the IRP was issued on July 29, 2020 (July 29 RFP), for 300 MW with commercial operation dates on or before May 31, 2023. The company sought 150 MW through long-term PPAs, and 150 MW through BTAs or company-proposed projects. October 14 application, pp. 2-3.

For the July 29 RFP, Consumers states that it selected Enel X North America, Inc. (Enel X) as the independent administrator. A copy of the report of the independent administrator for Enel X was included as an exhibit to the application. Enel X performed initial screenings of proposals and developed two separate blind rankings of proposals, one consisting of PPA proposals and another consisting of BTA proposals. After receiving Enel X's evaluations, Consumers ultimately selected the 150 MW Washtenaw Solar BTA, as well as the 100 MW Cereal City Solar Project PPA and the 125 MW Jackson County Solar Project PPA from the blind rankings. October 14 application, pp. 3-4; October 19 application, pp. 2-4. Consumers explains that it decided to pursue both PPAs, despite a 150 MW target for PPAs in the original RFP, because of the high quality of the projects and to mitigate the solar implementation risks the company has seen in recent projects. October 19 application, pp. 3-4.

In its October 14 application, the company states that Consumers and Washtenaw Solar executed a BTA with an effective date of October 4, 2021. Consumers filed a copy of the contract with certain sensitive portions redacted to protect confidential information that might negatively affect the competitive market. The Commission Staff reviewed unredacted versions of the documents on November 3, 2021. Washtenaw Solar is a solar facility that will be located in Washtenaw County, Michigan. The project is expected to achieve the full 30% investment tax credit (ITC). The Washtenaw Solar BTA includes several customer protections that are similar to the company's three previously approved BTA projects. The protections include: (1) liquidated damages should there be project delays; (2) a Milestone Progress Payment Schedule, which allows the company to take ownership of certain Project Assets as payments are made; and (3) a Purchase Price Adjustment associated with Steel, Shipping and Import Tariffs. Consumers explains that these provisions are designed to protect both Consumers and its customers if the project does not achieve its commercial operation date, thereby impacting qualification for the ITC. October 14 application, pp. 4-5.

Per Consumers, the installed cost of the Washtenaw Solar BTA is approximately $231.4 million and the total lifetime cost is approximately $433 million, or $56.91 per megawatt-hour (MWh) at the levelized cost of energy (LCOE). The project is expected to have a projected energy and capacity total lifetime market value of approximately $587 million and a total value of approximately $609 million including value added criteria.[1] October 14 application, p. 5; direct testimony of Beth Skowronski, p. 9. In the company's approved PCA in the 2018 IRP, the solar

[1] Value added criteria include, for example, the utilization of brownfields, distributed generation interconnection at a specified voltage level, Michigan-based companies for sourcing and manufacturing project materials, Michigan labor, prevailing wage, dispatchability guarantees, locations in designated low-income areas, or existing facilities. October 19 application, Exhibit No. A-2, pp. 75-76.

resource cost for a 400 MW solar facility with an asset life of 25 years had an average cost of $79.17 per MWh, or $3.2 million per installed MW. The average depreciable life cost of the Washtenaw Solar BTA is $54.46 per MWh, or $2.7 million per installed MW and the 35-year lifetime cost of the Washtenaw Solar BTA is $41.28 per MWh, or $2.9 million per installed MW. The forecasted revenue requirement of the 2018 IRP solar resource of $1.3 billion divided by the forecasted market value of $1.35 billion results in a cost-to-value ratio of 0.962 or 96.2%. The cost-to-value ratio of the Washtenaw Solar BTA is 94.7% over the depreciable life and 71.0% over the lifetime, which demonstrates that the cost-to-value ratio of Washtenaw Solar BTA is consistent with the cost-to-value ratio of the 2018 IRP solar resource on a total cost basis. October 14 application, pp. 5-6.

Consumers attests that the Washtenaw Solar BTA was acquired in a manner consistent with the requirements set forth in the settlement agreement approved by the June 7 order and is at a cost that is consistent with the modeled solar resource costs in the company's IRP. By seeking *ex parte* approval of the Washtenaw Solar BTA in this filing, the company states in its October 14 application that it is not seeking rate recovery related to the BTA; rather, Consumers intends to present its request for rate recovery related to the BTA in a future electric general rate case proceeding. *Id*., pp. 6-7.

In the October 19 application, Consumers states that it executed a 25-year PPA with Cereal City Solar on October 8, 2021, and a 20-year PPA with Jackson County Solar on October 15, 2021. According to Consumers, the PPAs are based on the company's proposed PPA as presented in the RFP. The purchase of capacity is based on zonal resource credits (ZRC). The capacity payments are made monthly at a fixed rate of $4,308.33 per ZRC-month. The PPA with Cereal City Solar provides for the purchase of energy at a fixed rate of $35.26 per MWh. The PPA with

Jackson County Solar provides for the purchase of energy at a fixed rate of $34.30 per MWh. Both PPAs are subject to the financial compensation mechanism (FCM) approved in Case No. U-20165. October 19 application, pp. 4-5.

Consumers estimates the cost to customers for the Cereal City Solar PPA to be $236.4 million in PPA supplier payments and $13.9 million in costs attributable to the FCM over the 25-year term of the PPA. The total forecasted cost is $250.3 million, or $51.51 per MWh at the LCOE. The estimated cost to customers for the Jackson County Solar PPA is $226.6 million in PPA supplier payments and $13.3 million in costs attributable to the FCM over the 20-year term of the PPA. The total forecasted cost is $239.9 million, or $50.80 per MWh at the LCOE. The projected energy and capacity market values for the Cereal City Solar PPA and the Jackson County Solar PPA $272.5 million and $267.2 million, respectively. The total market values, inclusive of value added criteria, are $282.9 million for the Cereal City Solar PPA and $285.0 million for the Jackson County Solar PPA. October 19 application, p. 5.

In the company's approved PCA in the 2018 IRP, the solar resource cost for a 400 MW solar facility with an asset life of 25 years had an average cost of $79.17 per MWh, or $3.2 million per installed MW. The average cost of the PPA with Cereal City Solar is $51.38 per MWh, or $2.5 million per installed MW. The average cost of the PPA with Jackson County Solar is $50.81 per MWh, or $1.9 million per installed MW. Consumers avers that the PPAs were acquired in a manner consistent with the requirements set forth in the settlement agreement approved by the June 7 order and at costs which are consistent with the modeled solar resource costs in the company's IRP. *Id*., pp. 5-7.

Discussion

MCL 460.6t provides, in relevant part, that in an IRP, the Commission shall do all of the following:

> (11) In approving an integrated resource plan under this section, the commission shall specify the costs approved for the construction of or significant investment in an electric generation facility, the purchase of an existing electric generation facility, the purchase of power under the terms of the power purchase agreement, or other investments or resources used to meet energy and capacity needs that are included in the approved integrated resource plan. The costs for specifically identified investments, including the costs for facilities under subsection (12), included in an approved integrated resource plan that are commenced within 3 years after the commission's order approving the initial plan, amended plan, or plan review are considered reasonable and prudent for cost recovery purposes.
>
> (12) Except as otherwise provided in subsection (13), for a new electric generation facility approved in an integrated resource plan that is to be owned by the electric utility and that is commenced within 3 years after the commission's order approving the plan, the commission shall finalize the approved costs for the facility only after the utility has done all of the following and filed the results, analysis, and recommendations with the commission:
>
> (a) Implemented a competitive bidding process for all major engineering, procurement, and construction contracts associated with the construction of the facility.
>
> (b) Implemented a competitive bidding process that allows third parties to submit firm and binding bids for the construction of an electric generation facility on behalf of the utility that would meet all of the technical, commercial, and other specifications required by the utility for the generation facility, such that ownership of the electric generation facility vests with the utility no later than the date the electric generation facility becomes commercially available.
>
> (c) Demonstrated to the commission that the finalized costs for the new electric generation facility are not significantly higher than the initially approved costs under subsection (11). If the finalized costs are found to be significantly higher than the initially approved costs, the commission shall review and approve the proposed costs if the commission determines those costs are reasonable and prudent.

MCL 460.6j(13) provides, in relevant part, that in a power supply cost reconciliation, the Commission shall do all of the following:

(b)Not disallow the capacity charges for any facilities for which the electric utility would otherwise have a purchase obligation if the commission has approved capacity charges in a contract with a qualifying facility, as that term is defined by the Federal Energy Regulatory Commission pursuant to the public utilities regulatory policies act of 1978, Public Law 95-617, 92 Stat 3117, unless the commission has ordered revised capacity charges upon reconsideration under this subsection. A contract is valid and binding in accordance with its terms, and capacity charges paid pursuant to that contract are recoverable costs of the utility for rate-making purposes notwithstanding that the order approving that contract is later vacated, modified, or otherwise held to be invalid in whole or in part if the order approving the contract has not been stayed or suspended by a competent court within 30 days after the date of the order, or by July 29, 1987 if the order was issued after September 1, 1986 and before June 29, 1987. The commission shall determine the scope and manner of the review of capacity charges for a qualifying facility. Except as to approvals for qualifying facilities granted by the commission before June 1, 1987, proceedings before the commission seeking those approvals shall be conducted as a contested case pursuant to chapter 4 of the administrative procedures act of 1969, 1969 PA 306, MCL 24.271 to 24.287. The commission, upon its own motion or upon application of any person, may reconsider its approval of capacity charges for a qualifying facility in a contested case hearing after passage of a period necessary for financing the qualifying facility, if both of the following apply:

(i) The commission has first issued an order making a finding based on evidence presented in a contested case that there has been a substantial change in circumstances since the commission's initial approval.

(ii) The commission finding is set forth in a commission order subject to immediate judicial review.

The Commission has reviewed Consumers' October 14 and 19 applications, the supporting testimony and exhibits, the settlement agreement approved by the June 7 order, and the language in MCL 460.6j and MCL 460.6t, and finds that the BTA and the PPAs were reasonably and prudently selected in a manner consistent with Consumers' 2018 IRP and should be approved. The Commission further finds that *ex parte* review and approval are appropriate as approval will not affect rates or rate schedules and will not increase the cost of service to customers. *See*, MCL 460.6a(3).

THEREFORE, IT IS ORDERED that the build transfer agreement between Consumers Energy Company and Washtenaw Solar Energy, LLC, and the power purchase agreements between Consumers Energy Company and Cereal City Solar, LLC, and Jackson County Solar, LLC, are approved as in compliance with Public Act 3 of 1939, as amended, and Consumers Energy Company's approved integrated resource plan in Case No. U-20165.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

_____
Daniel C. Scripps, Chair

_____
Tremaine L. Phillips, Commissioner

_____
Katherine L. Peretick, Commissioner

By its action of November 18, 2021.

_____
Lisa Felice, Executive Secretary

P R O O F O F S E R V I C E

STATE OF MICHIGAN)

Case No. U-20165

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on November 18, 2021 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna Brown

Subscribed and sworn to before me
this 18th day of November 2021.

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2024

Service List for Case: U-20165

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Appendix F: Excerpt of Consumers Energy's Application for Approval of an Amendment to Its Renewable Energy Plan in Case No. U-21816

Consumers Energy
Count on Us

November 15, 2024

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

RE: Case No. U-21816 – In the matter of Consumers Energy Company's application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find the **Application with supporting Testimony and Exhibits of Consumers Energy Company witnesses Kenneth D. Johnston, Marc R. Bleckman, Eugene M. Breuring, Thomas P. Clark, Zachary S. Cole, and Chibuzo C. Obikwelu**. Confidential Exhibits A-7 (TPC-1) through A-14 (TPC-8) and A-17 (TPC-11) through A-21 (TPC-15) are being filed under seal with the Michigan Public Service Commission.

This is a paperless filing and is therefore being filed only in PDF. Also included is a Proof of Service.

Sincerely,

Anne M. Uitvlugt

cc: Parties to Attachment 1 to Proof of Service

Consumers Energy
One Energy Plaza
Jackson, MI 49201-2357

www.consumersenergy.com

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of **CONSUMERS ENERGY COMPANY's** application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023.	)	Case No. U-21816

CONSUMERS ENERGY COMPANY'S APPLICATION FOR APPROVAL OF AN AMENDMENT TO ITS RENEWABLE ENERGY PLAN

Consumers Energy Company ("Consumers Energy" or the "Company"), pursuant to 2008 PA 295 ("Act 295"), as amended by 2023 PA 235 ("Act 235"), MCL 460.1022(3), applies to the Michigan Public Service Commission ("MPSC" or the "Commission") for approval of an Amendment to the Company's Renewable Energy Plan ("RE Plan"). In support of this Application, Consumers Energy states as follows:

1. Consumers Energy is, among other things, engaged as a public utility in the business of generating, purchasing, distributing, and selling electric energy to approximately 1.9 million retail customers in the state of Michigan. The retail electric system of Consumers Energy is operated as a single utility system, within which uniform rates are charged.

2. Consumers Energy's retail electric business is subject to the jurisdiction of the Commission pursuant to various provisions of 1909 PA 106, as amended, MCL 460.551 *et seq*.; 1919 PA 419, as amended, MCL 460.51 *et seq*.; 1939 PA 3, as amended, MCL 460.1, *et seq*.; and 2008 PA 295, as amended, MCL 460.1001, *et seq*. Pursuant to these statutory provisions, the Commission has the power and jurisdiction to regulate Consumers Energy's retail electric rates.

3. On October 6, 2008, Michigan enacted Act 295, which required certain electric providers, including Consumers Energy, to file proposed RE Plans with the Commission for its review and approval. Consistent with the requirements of Act 295, Consumers Energy submitted its 2009 RE Plan on February 17, 2009 in Case No. U-15805, which was originally approved in an Order issued May 26, 2009. The plan: (i) explained how the electric provider intended to meet the statutory renewable capacity and renewable energy targets; (ii) estimated the costs associated with meeting those targets; and (iii) proposed cost recovery mechanisms, including a Transfer Price mechanism to recover a portion of the total costs of implementing the RE Plan through the Power Supply Cost Recovery ("PSCR") process and a 20-year levelized surcharge to recover the Incremental Cost of Compliance.

4. The Company's RE Plan has subsequently been amended and reflects certain amendments previously approved by the Commission. See MPSC Case Nos. U-18231 and U-15805, February 7, 2019 Opinion and Order; MPSC Case No. U-20165, June 7, 2019 Order Approving Settlement Agreement; MPSC Case No. U-20984, September 9, 2021 Order Approving Settlement Agreement; MPSC Case No. U-21374, August 22, 2024 Order.

5. On November 28, 2023, Act 235 was signed into law and became effective on February 27, 2024. Among other things, Act 235 further amended Sections 22 through 49 of Act 295 to increase the Renewable Energy Credit Portfolio Standard ("RPS") for electric providers from 15% through 2029, to 50% in years 2030 through 2034, and 60% in 2035 and thereafter.

6. On December 4, 2008, the Commission issued a Temporary Order in Case No. U-15800 in which it established procedures for energy providers to follow in the preparation, submission, and processing of RE Plans. An Amendatory Order was issued on December 23, 2008. The renewable energy filing requirements were again evaluated and updated by the

Commission in Case No. U-18409. In its May 23, 2024 Order in Case No. U-21568, the Commission recently approved new filing requirements consistent with the requirements of Act 235.

7. MCL 460.1022(3) requires electric providers to file with the Commission their respective amended RE Plan within one year of the effective date of Act 235. In Case No. U-21568, on February 8, 2024, the Commission issued an Order requiring Consumers Energy to file its Amended RE Plan no later than November 15, 2024. See MPSC Case No. U-21568, February 8, 2024 Order, page 4.

8. Consumers Energy has developed reasonable modifications to its RE Plan that will achieve the requirements of Act 235. This RE Plan amendment, which runs through 2045, includes proposed updates to the renewable energy credit ("REC") compliance standard of 50% in 2030 through 2034, and 60% in 2035 and each year thereafter. The Company's Amended RE Plan also includes reasonable and prudent costs regarding both the incremental cost of compliance and PSCR Transfer Price, as well as the Company's election not to implement a revenue recovery mechanism at this time.

9. Consistent with the requirements of Act 295, as amended, Consumers Energy's Amended RE Plan addresses the following:

- The RPS targets set forth in MCL 460.1028, and how the Amended RE Plan aligns with the Company's approved 2021 Integrated Resource Plan ("IRP") in Case No. U-21090;
- How the REC portfolio will be calculated pursuant to MCL 460.1028;
- The eligible sources of RECs used to comply with RPS, as well as new compliance option available to certain qualifying customers as discussed in MCL 460.1028 and MCL 460.1029;
- The expected incremental cost of compliance for a 20-year period consistent with MCL 460.1045;

- The inclusion of a financial compensation mechanism on contracted renewable energy resource in accordance with MCL 460.1047;

- The bidding process to be used by the Company pursuant to MCL 460.1028(6); and

- Considerations regarding the inclusion of a revenue recovery mechanism for the recovery of the incremental costs of compliance provided for in MCL 460.1045.

10. To meet the requirements of Act 295, as amended, the Company seeks approval of certain modifications to the RE Plan previously approved in Case No. U-21374. In summary, these amendments include the following:

- Addition of up to 8,000 MW of both purchased and Company-owned solar energy resources consistent with the Company's settlement agreement in its 2021 IRP, Case No. U-21090. 690 MW of the solar capacity included is comprised of four IRP solar projects that will be incorporated in the RE Plan - Muskegon Solar, Spring Creek, Washtenaw Solar, and Mustang Mile. The planned solar additions also include 1,060 MW of proxy solar voluntary green pricing ("VGP") projects;

- Addition of up to 2,800 MW of Company-owned wind energy resources to support the increasing levels of REC compliance in 2030 and 2035;

- Adoption of the Company's projections for RPS considering the inclusion of calculation modifications for distributed generation outflow, VGP program participation, procurement of Midcontinent Independent System Operator, Inc. ("MISO") generated RECs, and the removal of RECs associated with generation from tire-derived fuel;

- Maintain 15% RPS through 2029; 50% REC compliance through 2034, and 60% REC compliance in 2035 and beyond;

- Propose the use of excess interconnection capacity with battery energy storage located at the Company's owned renewable asset sites;

- Maintain the current PSCR (transfer price) methodology and regulatory liability balance for Company-owned assets in the RE Plan through December 2045 and return to limiting transfer price to the Levelized Cost of Energy ("LCOE") for Company-owned facilities starting in 2034; and

- Utilize the Company's newly proposed simplified transfer price schedules which would replace the Company's transfer price schedules approved in Case Nos. U-15805 and U-16581.

11. The Company's proposals for the addition of wind and solar assets to comply with the 15% REC compliance through 2029; the 50% REC compliance through 2034, and the 60% REC compliance in 2035 and beyond will increase the total costs of the RE Plan compared to the total costs in the currently approved RE Plan. The total cost of this RE Plan pursuant to MCL 460.1047(2)(a)(i,ii,iii,iv) is approximately $27.8 billion, compared to the total cost of approximately $3.0 billion currently approved in the RE Plan. The total amount recovered through the PSCR process for this RE Plan is expected to be approximately $24.9 billion, compared to the PSCR expense of approximately $3.1 billion in the currently approved RE Plan. This amended RE Plan reflects total incremental costs of compliance of ($304 million), compared to the total incremental costs of compliance of $201 million in the RE Plan approved in Case No. U-21374. The addition of solar assets to support the Company's VGP programs will have a negligible effect on the total costs of the RE Plan due to subscription revenue offsets of the LCOE. These costs could be influenced by numerous factors that could either raise or lower the Company's implementation costs between now and 2045.

12. The Company's RE Plan Amendment leverages the renewable energy build plan approved in its 2021 IRP and has supplemented it with incremental wind energy renewable resources to achieve compliance with the 50% and 60% REC compliance requirements in 2030 and 2035, respectively. Additionally, the Company has modeled the purchase of RECs (up to 5%) from within the MISO footprint for use until 2035. The Company's modeling reflects a LCOE of $55.44/MWh for wind energy resource additions with a January 1, 2028 commercial operation date ("COD") and a LCOE of $70.31/MWh for solar energy resource additions with a January 1, 2028 COD and reflects a 2% annual escalation or reduction for projects with CODs in subsequent or prior years, respectively, for each resource type. The Company is requesting that the

Commission review the Company's future projects for solar and wind renewable energy resources on an *ex parte* basis if the project has a LCOE which is up to 140% above the LCOEs targets provided.

13. The Company's Amended RE Plan includes a mechanism for recovering the incremental cost of compliance within its rates and a forecast of the renewable energy resources needed to comply with the new RPS targets. As prescribed by MCL 460.1045(3), the Company's Amended RE Plan calculates the incremental cost of compliance for a 20-year period through 2045. While the Company will experience incremental costs of compliance on an annual basis through 2034, the incremental costs of compliance turned decidedly negative in 2035 through 2041, resulting in a projected regulatory liability at the end of the 20-year RE Plan period. As such, a levelized revenue recovery mechanism, as provided for in MCL 460.1045(3), for the 20-year period is unnecessary. The Company proposes to continue to maintain the current PSCR (transfer price) methodology and regulatory liability balance for Company-owned assets in the RE Plan through December 2045.

14. Consumers Energy is, concurrently with this Application, filing written testimony and exhibits in support of the relief the Company is seeking in this case. Reference to this material will provide additional details on the relief being sought. The relief described in the testimony and exhibits should be considered as if specifically requested in this Application.

REQUEST FOR RELIEF

WHEREFORE, Consumers Energy Company requests that the Michigan Public Service Commission:

A. Determine that the Company's RE Plan is reasonable and prudent, and that it meets all applicable requirements of Act 295, as amended by Act 235;

B. Modify the RE Plan to add up to 8,000 MW of both purchased and Company-owned solar energy resources consistent with the Company's settlement agreement in its 2021 IRP Case No. U-21090;

C. Approve and grant cost recovery of 690 MW of the solar energy resources related to Muskegon Solar, Spring Creek, Washtenaw Solar, and Mustang Mile projects;

D Modify the RE Plan to add up to 2,800 MW of new wind energy facilities;

E. Approve the use of excess interconnection capacity with battery energy storage located at the Company's owned renewable asset sites;

F. Maintain the current PSCR (transfer price) methodology and regulatory liability balance for Company-owned assets in the RE Plan through December 2045;

G. Approve the Company's newly proposed simplified transfer price schedules which would replace the Company's transfer price schedules approved in Case Nos. U-15805 and U-16581;

H. Grant Consumers Energy such other and further relief as is just and reasonable.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Dated: November 15, 2024

By: _____
Srikanth Maddipati
Vice President of Electric Supply
Consumers Energy Company

_____
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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of **CONSUMERS ENERGY COMPANY's** application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023.	)	Case No. U-21816

VERIFICATION

Srikanth Maddipati states that he is Vice President of Electric Supply at Consumers Energy Company; that he has executed the foregoing Application for and on behalf of Consumers Energy Company; that he has read the foregoing Application and is familiar with the contents thereof; that the facts contained therein are true, to the best of his knowledge and belief; and that he is duly authorized to execute such Application on behalf of Consumers Energy Company.

Dated: November 15, 2024

By: Sri M.

Srikanth Maddipati
Vice President of Electric Supply
Consumers Energy Company

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of **CONSUMERS ENERGY COMPANY's** application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023.	)	Case No. U-21816

DIRECT TESTIMONY

OF

ZACHERY S. COLE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

November 2024

Q. Please state your name and business address.

A. My name is Zachery S. Cole, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") where I am a Renewables Engineer responsible for Renewable Resources within the Electric Supply Regulatory Strategies Department.

QUALIFICATIONS

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Science Degree in Civil Engineering in 2020 from Michigan Technological University. From 2021 to 2022, I worked as a Design Engineer at Spicer Group Inc., where I was responsible for permitting, design, construction administration, and cost estimating of water resource related projects. In 2022, I joined Consumers Energy as an Associate Economics Engineer responsible for economic analyses related to new power purchase agreements ("PPAs"), renegotiation of existing PPAs, and analysis for ad hoc projects that support the Company's renewable energy electric generation strategy. In September 2023, I was promoted to a new role as a Renewables Engineer where my responsibilities were expanded to include implementation and the Company's compliance with its Renewable Energy Plan ("RE Plan").

Q. What are your present responsibilities and duties as Renewables Engineer?

A. My responsibilities include the implementation of the RE Plan, including (1) the development of competitive solicitations that add generation under the RE Plan, (2) negotiations and development of PPAs, and (3) ensuring compliance with the RE Plan.

Q. Have you completed other courses of study or attended any professional seminars?

A. Yes. I completed a training program entitled IPU Annual Regulatory Studies Program Fundamentals offered by the Institute of Public Utilities at Michigan State University.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I provided testimony in:

- Case No. U-21049: RE Plan expenses in the reconciliation of Power Supply Cost Recovery ("PSCR") Costs and Revenues for the Calendar Year 2022;
- Case No. U-21258: RE Plan expenses in the reconciliation of PSCR Costs and Revenues for the Calendar Year 2023;
- Case No. U-21549: the Company's 2024 Renewable Energy Cost Reconciliation case, regarding the actual and expected expenses incurred to implement the Company's approved RE Plan in 2023, the billed surcharge revenues, and a discussion on the Company's Regulatory Liability Balance projection; and
- Case No. U-21592: the Company's 2025 PSCR plan case for the 12 months ending December 31, 2025.

<u>PURPOSE OF TESTIMONY</u>

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to provide the following:

- Provide an overview of the Company's recent and future Voluntary Green Pricing ("VGP") request for proposals ("RFPs");
- Explain any new additions to the RE Plan;
- Support the continuation of the current PSCR methodology (transfer price) and regulatory liability balance for Company-owned assets in the RE Plan through December 2045;
- Support the Company's newly proposed simplified transfer price schedules which would replace the Company's transfer price schedules approved in Case Nos. U-15805 and U-16581; and
- Support the Company's VGP demand forecast.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-24 (ZSC-1)	Renewable Projected Electric Production – On Peak Generation;
Exhibit A-25 (ZSC-2)	Renewable Projected Electric Production – Off Peak Generation;
Exhibit A-26 (ZSC-3)	Renewable Projected Electric Production – Total Generation;
Exhibit A-27 (ZSC-4)	Renewable Energy Plan Projected Capped Transfer Costs;
Exhibit A-28 (ZSC-5)	Renewable Energy Plan Transfer Price Limits;
Exhibit A-29 (ZSC-6)	Renewable Energy Plan Projected FCM;
Exhibit A-30 (ZSC-7)	Simplified Transfer Price Schedules;
Exhibit A-31 (ZSC-8)	Existing vs Proposed Transfer Cost Comparison; and
Exhibit A-32 (ZSC-9)	VGP Subscription Forecast.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

RENEWABLE ENERGY GENERATION

Q. How many renewable energy systems included in the Company's RE Plan are expected to produce renewable generation through 2045?

A. There are several categories of renewable energy systems that can produce renewable generation through December 2045. They include:

1. Purchases of energy, capacity, and renewable energy credits ("RECs") through Renewable Energy Purchase Agreements ("REPAs") or PPAs;
2. Provider-owned renewable energy systems;
3. Renewable energy systems for which Commission authorization was previously obtained; and

4. Additional provider-owned VGP renewable energy systems for which Commission authorization is being sought in this filing.

The Transfer Price, as described and discussed further below, is only applied to: (i) purchases of energy, capacity, and RECs through REPAs and PPAs; (ii) production from provider-owned renewable energy systems; and (iii) production from Commission-authorized renewable energy systems. In 2024, the Company anticipates costs associated with: (i) REPAs supplying energy, capacity, and RECs in accordance with MCL 460.1047; (ii) Provider-owned renewable energy resources supplying energy, capacity, and RECs constructed in accordance with MCL 460.1047; and (iii) Commission-authorized renewable energy systems that participate in either Experimental Advanced Renewable Program ("EARP")-Solar or EARP-Anaerobic Digestion ("EARP-AD"). Costs for renewable energy systems for which recovery in electric rates was approved as of October 6, 2008 (the effective date of 2008 PA 295 ("Act 295") are recovered as part of power supply costs and general rates and are not considered in calculating Transfer Costs.

Q. What are the major Company-owned renewable energy additions to the RE Plan?

A. The Company has modeled the recovery of Muskegon Solar, Mustang Mile Solar, Spring Creek Solar, and Washtenaw Solar in the RE Plan, as discussed in the direct testimony of Company witness Kenneth D. Johnston. The Company is proposing to use the MPSC Staff's ("Staff") 2023 extended Transfer Price schedule, as filed in Case No. U-15800, for these four resources. Similarly, the Company is proposing to move recovery of all future renewable Integrated Resource Plan ("IRP") projects from the general rate case into the RE Plan. Additionally, the Company has selected two projects from the 2023 VGP RFP solicitation which are currently under negotiations. Finally, the Company anticipates

additional VGP and Solar Gardens projects to meet increasing demand. These projects can be seen in Exhibits A-24 (ZSC-1) through A-29 (ZSC-6).

Q. Are there major REPAs or PPAs for renewable energy being added to the RE Plan?

A. Yes. The Company is proposing to move the recovery and reconciliation of all future renewable IRP projects from the general rate case into the RE Plan, including PPAs. The Company is not proposing to move any existing PPAs to the RE Plan, however, all future renewable PPAs will be included in the RE Plan. For modeling purposes, the Company is assuming that roughly 50% of all future VGP and RE Plan solicitations for solar energy resources will be supplied via PPAs and the other 50% supplied by Company owned projects. The actual portfolio split may be different than the 50/50 split modeled in this case since the Company selects projects from VGP RFPs based on project economics. Exhibits A-24 (ZSC-1) through A-29 (ZSC-6) provide more insight into the assumed projects to be added to the RE Plan through 2045.

Q. Please summarize the sizes of renewable energy resources recoverable through the transfer price mechanism included in this plan.

A. This plan includes a total of 8,104 MW of solar projects which would be recoverable via the transfer price mechanism. Of that, 504 MW are solar projects already in the RE plan and 690 MW are due to the moving of 4 IRP assets into the RE plan. The remaining 6,910 MW are unnamed proxy solar projects, which includes 1,060 MW of unnamed proxy solar VGP projects. The additional 1,060 MW of proxy solar VGP projects combined with the existing 398 MW of named solar VGP projects and the 120 MW of named VGP wind projects brings the total VGP size to 1,578 MW.

Additionally, this plan includes a total of 2,800 MW of unnamed proxy wind projects and 1,200 MW existing wind projects recoverable via the transfer price mechanism. Finally, this plan includes 20 MW of existing resources that are not wind or solar technologies which are recoverable via the transfer price mechanism.

Q. Please provide an update on the 2023 VGP RFP.

A. On May 25, 2023, the Company's Independent Administrator, Enel X, issued the 2023 VGP solicitation on behalf of the Company to acquire up to 606 MW of additional aggregate nameplate capacity projects. The Company used a competitive VGP solicitation process consistent with prior solicitations for RE Plan assets, the Commission's 2008 Guidelines for Competitive Request for Proposal for Renewable and Advanced Cleaner Energy which were issued as Attachment D in the December 4, 2008 Order in Case No. U-15800, and the Commission's Competitive Procurement Guidelines for Rate-Regulated Electric Utilities (Not for PURPA Compliance) approved on September 9, 2021, in Case No. U-20852. On October 31, 2023, the Company provisionally awarded three solar projects, however after further due diligence, one of the projects has since been released. The Company continues to work toward execution of major contracts for the remaining two projects which would provide an estimated 347 MW of solar capacity for the Renewable Energy Program. Additional details regarding the 2023 VGP solicitation and the selected projects will be available when the Company files for MPSC approval of those projects.

Q. Has the Company issued additional VGP solicitations?

A. Yes. On July 3, 2024, the Company's Independent Administrator, Enel X, issued the 2024 Clean solicitation. The 2024 Clean solicitation solicited for up to 1,500 MW of clean generation to serve the Company's IRP, VGP, and the RE Plan.

Q. Is the 2024 Clean solicitation intended to supply all customers or just VGP?

A. The 2024 Clean solicitation allows the Company to be flexible when awarding projects. The Company could award a project to supply all customers, only VGP customers, or projects for both programs.

Q. What is the projected timeline for the 2024 Clean solicitation?

A. Bids for the 2024 Clean solicitation were due on October 9, 2024. The Company is targeting blind ranking results from Enel X by October 25, 2024. Following the performance of due diligence and negotiations, the Company is targeting to have executed contracts and file them with the MPSC for approval in the second quarter of 2025.

Q. How will the Company determine which projects to award regarding IRP/VGP?

A. Projects will be ranked based on economics first. If a project meets all the requirements of a project fit for the IRP portion of the RFP, it will be given first consideration for award to IRP and if not, then to VGP. Project awards will alternate between IRP and VGP when possible, to provide an even distribution of project awards between IRP/VGP. This method also reduces the opportunity for VGP to be supplied with all the lowest priced projects.

Q. How will the Company determine which projects to award regarding PPA/Owned?

A. The Company intends to award projects to the VGP program based primarily on project economics and does not have a preference for PPA/Owned for assets within the program.

PPAs will be evaluated based on the cost of the contract plus the applicable financial compensation mechanism.

COMPETITIVE SOLICITATION PROCESS

Q. How will the Company implement its future competitive solicitation process to match customer interest?

A. The Company will continue to be flexible in its implementation of competitive solicitations for VGP. The Sunfish 2 and D.E. Karn ("Karn") solar projects are fully subscribed, and the Company continues to receive subscriptions toward the next VGP asset additions. Further, the Company could issue subsequent VGP solicitations for utility scale wind and solar projects based upon customer demand. The Company has not yet established a date for any future VGP solicitations.

Q. Will future VGP solicitations be consistent with prior RE Plan, IRP, and VGP solicitations?

A. Yes. The Company will continue to use a competitive VGP solicitation process consistent with prior solicitations for RE Plan assets, the Commission's 2008 Guidelines for Competitive Request for Proposal for Renewable and Advanced Cleaner Energy which were issued as Attachment D in the December 4, 2008 Order in Case No. U-15800, and the Commission's Competitive Procurement Guidelines for Rate-Regulated Electric Utilities (Not for PURPA Compliance) approved on September 9, 2021, in Case No. U-20852.

TRANSFER COST

Q. Has the Company included a portion of the costs incurred in implementing its RE Plan in the Company's 2025 PSCR Plan proceeding?

A. Yes. MCL 460.1047(2)(b)(iv) provides that the Renewable Energy costs included in the PSCR Plan shall be considered "a booked cost of purchased and net interchanged power transactions under section 6j of 1939 Public Act 3, MCL 460.6j." These are the costs expected to be recovered through the PSCR mechanism that is discussed in the Company's RE Plan (referred to as the "Transfer Price" or the "Transfer Cost").

Q. What is the Transfer Cost?

A. The Transfer Cost is the total cost that the Company will transfer to power supply costs in accordance with MCL 460.1047(2)(b)(iv) associated with renewable generation obtained in accordance with MCL 460.1047.

Q. How much renewable generation, for which the Transfer Price applies, is anticipated for delivery through 2045?

A. Exhibits A-24 (ZSC-1) through Exhibit A-26 (ZSC-3), "Renewable Projected Electric Production – On-Peak, Off-peak, & Total Generation," provides details of the projected annual on-peak, off-peak, and total electric production of renewable generation applicable to the Transfer Price. Column (az) represents the total energy from REPAs, EARP-AD, EARP-Solar, and the subscribed portion of Solar Gardens. Columns (bb), (bc), and (bd) show the unsubscribed portion of Solar Gardens. Columns (bh) and (bi) show the unsubscribed portions of the Cross Winds II facility and the Cross Winds III facility. The total energy from Provider-Owned Renewable Energy systems is shown in column (db)

and column (dc) shows the total of all MWhs of Transfer Price-applicable renewable generation.

Q. How is the expected energy from these facilities calculated?

A. For existing units online greater than 3 years, the estimates of future energy production are based on the 3-year historic annual average generation. This method considers the maximum number of RECs allowed under the contracts due to historic production being held to the same contractual requirement. The following units use the three-year historic average method: REPAs already in the RE Plan (excludes River Fork Solar), all EARPs, Lake Winds Energy Park, Cross Winds Energy Park, Cross Winds Energy Park II, Cross Winds Energy Park III, Gratiot County Wind Farm, Crescent Wind Farm, and Circuit West Solar. Units that do not have three years of historic generation data are forecasted based on project size and technology (and if known, capacity factors). Units that do not have three years of historic generation data include River Fork Solar, Heartland Wind Farm, Muskegon Solar, Mustang Mile Solar, Spring Creek Solar, Washtenaw Solar, all future VGP and Solar Gardens expansions, and future IRP/RE Plan projects.

Q. Please describe Exhibits A-24 (ZSC-1) through A-26 (ZSC-3).

A. Exhibit A-24 (ZSC-1) shows the individual and total on-peak generation expected from renewable energy generation in the RE Plan projected through 2045. Exhibit A-25 (ZSC-2) shows the individual and total off-peak generation expected from renewable energy generation in the RE Plan projected through 2045. Exhibit A-26 (ZSC-3) shows the total generation expected from renewable energy generation in the RE Plan projected through 2045.

Q. Please describe Exhibit A-27 (ZSC-4).

A. Exhibit A-27 (ZSC-4) shows the total amount of projected actual transfer costs expected from renewable generation delivered through 2045. The projected REPA, EARP-AD, EARP-Solar, and the subscribed portion of the Solar Gardens transfer costs are shown in columns (b) through (ay). The projected transfer costs of Company-owned facilities and the unsubscribed portion of the Solar Gardens project are shown in columns (bb) and (db), the unsubscribed portions of the Cross Winds II facility and the Cross Winds III facility are included in columns (bh) and (bi), and the grand total of all sources is shown in column (dc). Note that the proxy VGP assets have $0 in total transfer costs due to the Company's assumption that all Renewable Energy Program assets will be fully subscribed. This exhibit details the amount expected to be recovered through the PSCR mechanism.

Q. Please describe Exhibit A-28 (ZSC-5).

A. Exhibit A-28 (ZSC-5) outlines the maximum amount of Transfer Cost that can be booked for each resource. For REPAs and EARP-Solar, the Transfer Cost is limited to the total amount paid to each counterparty for the energy, capacity, and RECs anticipated to be booked. For Company-owned facilities, the maximum Transfer Cost is calculated by multiplying the applicable transfer price, assigned when the unit was first added to the program, by its total generation.

Q. How were the cost estimates for REPAs and Renewable Energy Programs derived?

A. The REC price is established in all the REPAs except for the contract with Apple Blossom. To estimate the REC costs, I created a simplified forecast of RECs which should generally align with the forecast of RECs shown in Exhibit A-35 (CCO-3), page 1, then multiplied the forecasted RECs by the contracted REC prices to arrive at the cost for RECs. The

forecasted on-peak energy costs associated with REPAs were determined by applying the on-peak contract prices to the forecast of on-peak energy production shown in Exhibit A-24 (ZSC-1). The forecasted off-peak energy costs associated with REPAs were determined by applying the contract off-peak prices to the forecast of off-peak energy production shown in Exhibit A-25 (ZSC-2). To estimate future capacity costs, the actual Zonal Resource Credits ("ZRCs") awarded to each plant in the 2024 planning year was multiplied by the contracted capacity payment rate.

The Company PPAs with Apple Blossom, EARP-Solar, and EARP-AD Agreements provide for payments based solely on energy production.

<u>TRANSFER PRICE</u>

Q. What is the Transfer Price?

A. The Transfer Price is the price at which the cost of renewable energy is recovered through the Company's PSCR clause pursuant to MCL 460.1047 and MCL 460.1049 and as established by the Commission. The Transfer Price was defined in the Commission's December 4, 2008 Order in Case No. U-15800, pages 25 and 26. On pages 25 and 26 of that Order, the Commission stated:

> 4. Calculation of the incremental cost of compliance via the transfer price to be recovered through the PSCR clause.
>
> A provider whose rates are regulated by the Commission shall include in its renewable energy plan an estimate over the 20-year plan-period of the revenues derived from the sale of energy and capacity generated by renewable energy systems owned by the provider. Energy and capacity produced by these systems may be sold into the wholesale market, or may be sold directly to the provider's customers.
>
> Section 47 requires the Commission to annually set the price per megawatt hour to be transferred to retail customers through the regulated provider's power supply cost recovery (PSCR) clause. Section 49 requires the transfer price to be

established in the context of an annual renewable cost reconciliation proceeding. Because the 2009 renewable energy plan proceeding will precede the first annual renewable energy reconciliation, the plan filings will need to estimate the transfer prices over the 20-year plan period. All renewable engineering, procurement, and construction contracts, or contracts for renewable energy systems that have been developed by third parties for transfer of ownership to an electric provider, that have been reviewed and approved by the Commission in a particular year will have the transfer price established as a floor for the lifecycle of the project. Provider owned projects will have transfer prices set in vintages. Doing so ensures that the economic viability of projects that have been committed to will not be jeopardized by transfer prices that change in future years.

In a renewable energy plan, PSCR transfer revenues are subtracted from the total cost of compliance, as determined by Section 47(2)(a). The transfer price is a primary determinant of the incremental cost of compliance. The PSCR transfer price:

(a) is unique to each provider;

(b) reflects the value of long-term capacity and energy;

(c) is not the current MISO market price of energy, but may use historical MISO prices as a starting point for a 20-year projection of the value of renewable energy and capacity;

(d) need not be tied to the avoided price of a new conventional coal-fired facility; and

(e) other factors determined relevant by the Commission.

The transfer price may be separately calculated for differing renewable technologies to reflect availability and the value of capacity; e.g., the capacity value of a landfill gas facility may differ from the capacity value of a wind farm.

The PSCR transfer price may be adjusted by an hourly distribution curve to yield an hourly price per megawatt hour for the 8,760 hours per year.

The forecasted Transfer Price for the period 2024 through 2045 is estimated to be $72.67/MWh.

Q. How did the Company calculate the Transfer Price?

A. To determine the Transfer Price, the Company calculated the total Transfer Costs during the period (as shown in column (dc) of Exhibit A-27 (ZSC-4)) and divided the Transfer Cost by the corresponding Transfer Price applicable renewable energy quantity (as shown in column (dc) of Exhibit A-26 (ZSC-3)) delivered during the period.

Q. Is the Company proposing any changes to the transfer price that is currently in place?

A. No. While the Company's modeling assumes that no costs from the Renewable Energy Program renewable energy resources will be transferred to the PSCR via the transfer price mechanism, the modeling does indicate that the original transfer price mechanism that was re-established in Case No. U-20483 needs to continue to remain in place to maintain a regulatory liability balance. Through the renewable energy cost reconciliation filings, the Company has previously committed to returning to limiting transfer price to the levelized cost of energy ("LCOE") for Company-owned facilities when the risk of dipping into a regulatory asset position is low. As a result of Michigan's Act 235, the Company is proposing to return to limiting transfer price to the LCOE for Company-owned facilities starting in 2034 and continuing for the remainder of the plan period. The modeling in this proceeding is based upon a return to that transfer price methodology beginning in 2034. The Company will continue to report on the status of the regulatory account balance in its annual renewable energy cost reconciliation proceedings.

Q. How do existing and new VGP assets affect the PSCR via the transfer price mechanism?

A. Subscribed portions of VGP assets have zero impact on the PSCR as no costs are transferred to the PSCR. As previously discussed, customers that participate in VGP programs pay the subscription price of the asset(s) to which they are subscribed for their energy usage for the duration of their contract. As an offset to the subscription price, VGP customers receive monthly credits for the energy and capacity value of the resource(s) to which they subscribed. To the extent that any unsubscribed portions of VGP facilities exist, they would be transferred to the PSCR at their LCOE.

NEW TRANSFER PRICE SCHEDULES

Q. What is a Transfer Price schedule?

A. According to Staff's 2024 Transfer Price Schedule Report filed April 18, 2024, "The transfer price concept was originally established through legislation in 2008 Public Act 295 (PA 295). PA 295 Section 49(3)(c) described a volumetric recovery mechanism utilizing the power supply cost recovery clause for renewable energy and capacity… transfer price schedules should be representative of what a Michigan electric provider would pay had it obtained the energy and capacity (the non-renewable market price component) through a long-term power purchase agreement for traditional fossil fuel electric generation."

Q. What is the Company proposing to change with regard to the existing Transfer Price schedules?

A. The Company is proposing a new Transfer Price schedule which would replace the existing Transfer Price schedules (Case Nos. U-15805 and U-16581) for the following assets: Beebe Renewable Energy, Fremont Community Digester, Harvest II Windfarm, Heritage

Garden Windfarm I (wind), Heritage Garden Windfarm I (solar), Heritage Garden Stoney Corners Windfarm I (Phase 2), Heritage Garden Stoney Corners Windfarm I (Phase 3), Michigan Wind 2, North American Natural Resources (Lennon), WM Renewable Energy (Northern Oaks), WM Renewable Energy (Pine Tree Acres), EARP Solar Aggregate No. 5. Additionally, the Company is proposing to assign the Lake Winds Energy Park, and Lake Winds Energy Park Repowered projects to its own unique Transfer Price schedule.

Q. Why is the Company proposing new Transfer Price schedules for certain projects which have already been assigned to a transfer price schedule?

A. The Company is proposing new, simplified, Transfer Price schedules to reduce the administrative burden, and reduce potential errors, associated with the existing Transfer Price schedules approved in Case Nos. U-15805 and U-16581. The existing schedules include a monthly on-peak rate, monthly off-peak rate, and monthly capacity rate. More recently, Staff proposed Transfer Price schedules do not include a capacity rate and include only a yearly total $/MWh rate. The Company is proposing to align the new Transfer Price schedule structure with that of Staff's schedules.

Q. How did the Company create the newly proposed schedules?

A. The Company created two new Transfer Price schedules, one for the REPAs which were formerly assigned to the Transfer Price schedules approved in Case Nos. U-15805 and U-16581, and one for Lake Winds Energy Park and Lake Winds Energy Park Repowered. Both schedules were created using the same methodology described below. The Company first modeled the total Transfer Cost of the units which would be assigned the new schedule and recorded the total forecasted Transfer Cost associated with those units using the existing Transfer Price schedules. The Company then modeled those same units using a

proxy Transfer Price schedule which was structurally different from the existing schedule (structurally similar to Staff's proposed schedules – one rate for all energy delivered in a year, no capacity rate). The new (proxy) schedule was determined by, for each year, setting the Transfer Rate ($/MWh) for a given year such that the new forecasted total Transfer Cost associated with these units would be equal to (or nearly equal to) the total forecasted Transfer Cost associated with these units under the existing schedules. The value of the new single value (as opposed to on-peak/off-peak and capacity) for Transfer Rate ($/MWh) for a given year generally falls in between the former on-peak schedule rate and off-peak schedule rate but is not simply the average due to the pooled resource generation profile not producing during exactly 50% on-peak and 50% off-peak hours and the existing schedules inclusion of capacity-based transfer costs. To state simply, the newly proposed Transfer Price schedules are based on the existing Transfer Price schedules applicable to these units and is similar to a weighted average of the on-peak/off-peak and capacity transfer rates based on the resource pool's generation profile/capacity accreditation. The new Transfer Price schedules were created using the Transfer Price Forecast model such that there would be very little impact to the total Transfer Cost associated with these 14 units as seen in column (h) of Exhibit A-31 (ZSC-8).

Q. How will this impact the Transfer Cost of these projects and thus the total Transfer Cost?

A. As previously discussed, the new Transfer Price schedules were created with the primary goal of reducing the impact to the total cost transferred to PSCR via the Transfer Price mechanism associated with these 14 units. As seen in Exhibit A-31 (ZSC-8), for the period 2025 through the end of 2045, the newly proposed schedules result in an estimated net total

decrease of $20 when comparing the forecasted total cost transferred to PSCR with the existing Transfer Price schedules. Compared to the forecasted total cost (using the newly proposed schedules) transferred to PSCR over the same period of $24.5 billion, as seen in Exhibit A-27 (ZSC-4), column (dc), row 92, less column (dc), row 70, the forecasted net total $20 decrease is insignificant.

Q. The newly proposed Transfer Price schedules were created based on forecasted Transfer Costs and the primary goal in creating the new schedule was to reduce or eliminate the impact to the forecasted total Transfer Cost. Are there variables that may change how closely the new schedules follow the existing schedules in terms of total Transfer Costs to PSCR?

A. Yes. There are a number of factors that could impact how closely the new Transfer Price schedule performs in comparison to the existing Transfer Price schedules. The largest factor is the on-peak/off-peak generation split. The new schedules were created using a three-year historical average of generation during on-peak and off-peak hours. A divergence of the total transfer cost could occur if a unit significantly strays from its historical on-peak/off-peak energy production (including outages). Similarly, a significant change to the capacity credit (ZRCs) for these units in comparison to their three-year historic average could also create a divergence of the total transfer costs.

Q. Could the Company simply assign these plants to Staff's latest transfer price schedule rather than creating a whole new transfer price schedule?

A. No. Transfer Price schedules are released by Staff annually in order to incorporate changes in cost assumptions associated with the proxy plant modeled when setting the Transfer Price schedules. Therefore, it is important to utilize Transfer Price schedules that were

created in a relatively similar timeframe that these plants were constructed or brought into the RE Plan.

VGP FORECAST

Q. Why is the Company providing a forecast of VGP subscriptions?

A. The Company is including a VGP subscription forecast (shown in Exhibit A-32 (ZSC-9) as a result of legislation in Act 235. MCL 460.1028(2)(b)(ii) describes a portion of the calculation of the renewable energy credit portfolio standard ("RPS"). The calculation indicates that "the amount of sales attributable to customers participating in an electric provider's voluntary green pricing program under section 61…" should be removed from the RPS compliance calculation.

Q. Please describe Exhibit A-32 (ZSC-9).

A. Exhibit A-32 (ZSC-9) is the Company's VGP subscription forecast. Columns (b), (c), (d), and (e) represent the Company's forecast of subscriptions for the following VGP program customers respectively: Residential & Green Giving, Commercial & Industrial, and Solar Gardens. Columns (f) and (g) represent the incremental amount of Solar and Wind (respectively) resources the Company anticipates adding to the VGP program to supply the subscriptions shown in columns (b) through (e). Note that for 2024, the resources listed under columns (f) and (g) are existing assets rather than new assets. Column (h) is the forecasted Cumulative total supply for the VGP program. Column (i) is the forecasted incremental total supply for each year (Solar plus Wind). Column (j) provides project names associated with the incremental supply columns. Column (k) provides project assumptions and notes.

Q. Please explain how the Company came up with the values under the Renewable Energy Program-Residential & Green Giving column.

A. As Residential and Green Giving are new VGP program offerings scheduled to launch January 1, 2025, the forecasted subscribed MWh values under column (b) are based on residential VGP program benchmarks and customer behavior modeling. Enrollment volume estimates were paired with anticipated program subscription levels; 50% subscription for Green Giving based on approved tariff, and 25% subscription for Residential Renewable Energy Program associated with willingness to pay analysis. Lastly, an annual attrition rate of 7.4% was applied to total subscribed energy estimates based on historical Green Generation data. The values under the Renewable Energy Program-Residential & Green Giving column (b) from 2025 through 2029 are based on the inputs noted above and the Company's program launch plans. Values from 2030 through 2035 are based on an assumed annual growth rate of 5%. Subscription volume values from 2036 through 2045 remain flat based on achieving 0.7% saturation and the assumption that as the Company reaches it's 60% RPS standard in 2035, growth in customer enrollments will diminish. In total, Residential Renewable Energy Program and Green Giving subscription volume estimates total 80,166 MWh which equates to 42 MW of new solar using a net capacity factor of 22%.

Q. Please explain how the Company came up with the subscription levels under the Renewable Energy Program Commercial & Industrial subscribed load column.

A. The subscription levels under the Renewable Energy Program Commercial & Industrial column from 2024 through 2028 represent the estimated production from projects the Company has under development less the forecasted Renewable Energy Program-

Residential/Green Giving subscriptions since both programs will be supplied by the same asset pool. This assumes each project is fully subscribed. The Company has firm subscriptions for all the assets that have been added to the VGP program and continues to subscribe new customers for future VGP assets. The subscription levels under the Renewable Energy Program Commercial & Industrial column from 2029 through 2045 are based on an assumed target of 15% of commercial & industrial load by 2035. The Company is assuming approximately 15% of commercial & industrial load will be subscribed to the Renewable Energy Program by 2035. The estimated 1,670,089 MWh shown in column (c) for 2028 represents the estimated average annual amount of production from projects the Company currently has under development less the value for Residential/Green giving in column (b). This level of production is assumed to continue for the remaining years of the forecast. 15% of commercial & industrial load (based on the Company's Annual Report of Consumers Energy Company to the Michigan Public Service Commission For the year Ended December 31, 2022) represents an estimated 3,011,939 MWh. The sizes of the additional projects needed to supply the Renewable Energy Program & Residential/Green Giving with Commercial Operation Dates estimated in 2029-2035 were backed into based on the annual production needed, or 15% commercial & industrial load value (3,011,939 MWh) plus the Residential/Green Giving saturation point (80,166 MWh) less the amount of production from projects currently under development (1,709,605 MWh – sum of 2028 columns (b) & (c)). This amount (1,382,500 MWh) represents the amount of supply the Company should procure based on the forecasted demand for the Renewable Energy Program Commercial & Industrial &

Residential/Green Giving forecast and is equivalent to an estimated 717 MW of Solar resources.

Q. Please explain how the Company came up with the values under column (d), Solar Gardens Subscribed Load, in Exhibit A-32 (ZSC-9).

A. The Company created the Solar Gardens customer demand forecast (column (d)) based on the Company's current 10 MW cap on the Solar Gardens program. Column (d) in the forecast assumes a 2.5 MW addition to the Solar Gardens supply in 2026 which is subscribed over the course of four years. The Company assumes an additional 3 MW project to come online in 2030 and be fully subscribed over the course of five years which would put the Solar Garden program at the 10 MW cap. The Solar Gardens subscription forecast is held constant beyond 2035 due to the current 10 MW cap on the program.

Q. Why are the Renewable Energy Program Proxy Units in 2029-2035 not showing any costs in the Transfer Price Exhibits?

A. All projects supplying the Renewable Energy Program, named or proxy, are assumed to be fully subscribed. Subscribing customers will be paying for the cost of the projects. In the event a portion of one or more VGP resources are unsubscribed at the end of the year, that portion will be transferred to PSCR at the LCOE of the project. Additionally, while the subscribed portion of Renewable Energy Program assets are included in the Transfer Price exhibits (Exhibits A-24 (ZSC-1) through A-29 (ZSC-6)) for informational purposes, they are not included in any of the totals on said exhibits.

<u>CONCLUSION</u>

Q. Does this conclude your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of **CONSUMERS ENERGY COMPANY's** application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023.	)	Case No. U-21816

EXHIBITS

OF

ZACHERY S. COLE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

November 2024

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

CASE NO. U-21962
EXHIBIT A-24 (ZSC-1)
PAGE 1 OF 1
WITNESS: ZSC-1R
DATE: November-2024

Renewable Projected Electric Production
On Peak Generation

Line No.	Generator	Apple Blossom	Beebe Renewable Energy	Elk Rapids Hydro	Fremont Community Digester	Harvest II Windfarm	Heritage Garden Windfarm (Wind)	Heritage Garden Windfarm (Solar)	Heritage Sheng Cenovus Windfarm (HSC Phase I)	Heritage Sheng Cenovus Windfarm (HSC Phase II)	Michigan Wind 2	North American Natural Resources (Lennon)	Scenic View Dairy (Pennville)	Scenic View Dairy (Freeport)	Willkomm Solar (Berrien-Cass)	Willkomm Solar (Pine Tree Acres)	Zeeland Farm Services (Phase 2)	SAMP - 1-4	SAMP - 5	SAMP - 6	SAMP - 7	SAMP - 8	SAMP - 9	SAMP - 10	SAMP - 11	SAMP- Anaerobic Digester	River Park Solar	Solar Gardens (Subscribed)	Solar Gardens 2020 Expansion (Subscribed)	Solar Gardens 2020 Expansion (Subscribed)
	Year	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
1	2024	118,138	87,792	-	5,218	81,369	20,172	1,845	10,992	7,665	117,880	4,411	-	-	2,495	28,831	-	-	546	562	332	547	715	267	129	-	27,936	3,946	-	-
2	2025	118,138	87,792	-	5,218	81,369	20,172	1,845	10,992	7,665	117,880	4,411	-	-	2,495	28,831	-	-	546	562	332	547	715	267	129	-	28,836	3,946	347	-
3	2026	118,138	87,792	-	5,218	81,369	20,172	1,845	10,992	7,665	117,880	4,411	-	-	2,495	28,831	-	-	546	562	332	547	715	267	129	-	29,740	3,946	347	-
4	2027	118,138	87,792	-	5,218	81,369	20,172	1,845	10,992	7,665	117,880	4,411	-	-	2,495	28,831	-	-	546	562	332	547	715	267	129	-	30,644	3,946	1,041	-
5	2028	118,138	87,792	-	5,218	81,369	20,172	1,845	10,992	7,665	117,880	4,411	-	-	2,495	28,831	-	-	546	562	332	547	715	267	129	-	30,644	3,946	1,038	-
6	2029	118,138	87,792	-	5,218	81,369	20,172	1,845	10,992	7,665	117,880	4,411	-	-	2,495	28,831	-	-	-	-	-	-	-	-	-	-	30,644	3,946	2,143	-
7	2030	118,138	87,792	-	5,218	81,369	20,172	1,845	10,992	7,665	117,880	4,411	-	-	2,495	28,831	-	-	-	-	-	-	-	-	-	-	30,644	3,946	2,238	341
8	2031	118,138	87,792	-	5,218	81,369	20,172	1,845	10,992	7,665	117,880	-	-	-	-	28,831	-	-	-	-	-	-	-	-	-	-	30,644	3,946	2,238	754
9	2032	118,138	87,792	-	5,218	81,369	20,172	1,845	10,992	7,665	117,880	-	-	-	-	7,208	-	-	-	-	-	-	-	-	-	-	30,644	3,946	2,238	1,754
10	2033	118,138	87,792	-	5,218	81,369	20,172	-	10,992	7,665	117,880	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30,644	3,946	2,213	1,754
11	2034	118,138	87,792	-	-	81,369	20,172	-	10,992	7,665	117,880	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76,736	3,946	2,390	2,385
12	2035	118,138	87,792	-	-	81,369	20,172	-	10,992	7,665	117,880	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76,636	3,946	2,387	2,485
13	2036	118,138	87,792	-	-	81,369	20,172	-	10,992	7,665	117,880	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76,636	3,946	2,384	2,485
14	2037	118,138	87,792	-	-	81,369	20,172	-	10,992	7,665	117,880	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76,636	3,946	2,372	2,485
15	2038	118,138	87,792	-	-	81,369	20,172	-	10,992	7,665	117,880	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77,897	3,946	2,238	2,364
16	2039	118,138	87,792	-	-	81,369	20,172	-	10,992	7,665	117,880	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77,936	3,946	2,238	2,387
17	2040	118,138	87,792	-	-	81,369	20,172	-	10,992	7,665	117,880	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	78,036	3,946	2,343	2,482
18	2041	118,138	87,792	-	-	81,369	20,172	-	10,992	7,665	117,880	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77,842	59	2,238	2,380
19	2042	118,138	87,792	-	-	81,369	20,172	-	10,992	7,665	117,880	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77,842	-	2,238	2,380
20	2043	118,138	87,792	-	-	81,369	20,172	-	10,992	7,665	117,880	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50,176	-	2,243	2,385
21	2044	118,138	87,792	-	-	81,369	20,172	-	10,992	7,665	117,880	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,238	2,380
22	2045	118,138	87,792	-	-	81,369	20,172	-	10,992	7,665	117,880	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,238	2,380
23	TOTAL	2,628,047	1,955,797	-	47,260	1,790,111	447,791	16,057	242,846	175,038	2,593,574	38,675	-	-	17,466	245,937	-	-	1,092	2,123	1,280	2,132	2,786	1,122	516	-	1,056,496	76,479	42,772	32,543

Line No.	Generator	REP 2020 PPA In-State Solar 100 MW	REP 2020 PPA In-State Solar 200 MW	REP 2021 PPA In-State Solar 200 MW	REP 2022 PPA In-State Solar 150 MW	REP 2022 PPA In-State Solar 250 MW	REP 2024 PPA In-State Solar 250 MW	REP 2025 PPA In-State Solar 100 MW	REP 2026 PPA In-State Solar 200 MW	REP 2027 PPA In-State Solar 150 MW	REP 2028 PPA In-State Solar 125 MW	REP 2029 PPA In-State Solar 62.5 MW	2028 VGP REP PPA In-State Solar 61.5 MW	2030 VGP REP PPA In-State Solar 43.5 MW	2031 VGP REP PPA In-State Solar 55.5 MW	2032 VGP REP PPA In-State Solar 43.5 MW	2033 VGP REP PPA In-State Solar 27.5 MW	2034 VGP REP PPA In-State Solar 27.5 MW	2035 VGP REP PPA In-State Solar 27.5 MW	REP Level Program Total
	Year	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
24	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**536,033**
25	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**563,051**
26	2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**602,045**
27	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**642,183**
28	2028	210,936	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**753,051**
29	2029	210,240	393,636	-	-	-	-	-	-	-	-	-	83,506	-	-	-	-	-	-	**1,149,277**
30	2030	208,790	391,426	333,198	-	-	-	-	-	-	-	-	83,506	76,493	-	-	-	-	-	**1,093,413**
31	2031	206,976	389,060	330,423	392,566	-	-	-	-	-	-	-	83,506	77,893	74,651	-	-	-	-	**1,554,539**
32	2032	205,161	386,695	327,648	390,192	384,760	-	-	-	-	-	-	83,506	77,893	73,251	76,248	-	-	-	**2,504,154**
33	2033	207,012	387,126	328,897	392,668	382,404	354,212	-	-	-	-	-	83,506	77,893	73,845	86,768	69,563	-	-	**2,897,563**
34	2034	206,646	384,846	326,612	390,381	380,126	351,857	353,668	-	-	-	-	83,506	76,946	73,380	86,239	68,160	42,958	-	**2,837,048**
35	2035	204,870	383,024	324,990	388,760	378,501	350,350	352,938	351,838	-	-	-	83,506	76,946	72,800	86,039	68,058	42,958	41,461	**3,583,188**
36	2036	203,708	381,262	323,051	386,819	376,567	348,395	350,124	350,060	350,060	-	-	83,506	76,107	72,412	85,839	67,223	42,277	42,277	**3,539,941**
37	2037	203,475	381,028	322,818	386,586	376,334	348,163	349,891	350,127	350,127	350,060	-	83,506	76,107	72,375	85,839	66,987	42,293	42,293	**3,573,192**
38	2038	203,475	381,028	322,818	386,586	376,334	348,163	349,891	350,127	350,127	350,060	350,060	83,506	76,107	72,375	85,839	66,987	42,293	42,293	**3,573,192**
39	2039	202,313	379,866	321,656	385,423	375,172	347,000	348,728	348,964	349,964	349,897	350,060	83,506	76,107	72,375	85,839	66,987	42,293	42,293	**3,561,543**
40	2040	198,837	376,390	318,180	382,947	371,696	343,524	345,252	345,488	346,488	346,421	346,584	83,506	76,107	72,375	85,839	66,987	42,293	42,293	**3,526,079**
41	2041	198,604	376,157	317,947	382,714	371,463	343,291	345,019	345,255	346,255	346,188	346,351	177,245	76,107	72,375	85,839	66,987	42,293	42,293	**3,726,145**
42	2042	198,604	376,157	317,947	382,714	371,463	343,291	345,019	345,255	346,255	346,188	346,351	176,263	38,676	72,375	85,839	66,987	42,293	42,293	**3,726,145**
43	2043	198,492	376,044	317,834	382,601	371,350	343,178	344,906	345,142	346,142	346,075	346,238	177,033	68,990	72,375	85,839	66,987	42,293	42,293	**3,726,145**
44	2044	198,492	376,044	317,834	382,601	371,350	343,178	344,906	345,142	346,142	346,075	346,238	176,376	68,128	72,375	85,839	66,987	42,293	42,293	**3,726,145**
45	2045	198,492	376,044	317,834	382,601	371,350	343,178	344,906	345,142	346,142	346,075	346,238	176,376	68,128	72,375	85,839	66,987	42,293	42,293	**3,726,145**
46	TOTAL	**3,473,636**	**5,797,146**	**4,171,736**	**5,145,233**	**4,817,948**	**4,495,892**	**4,153,518**	**3,838,938**	**3,452,914**	**3,345,362**	**3,033,231**	**1,231,218**	**929,798**	**1,358,124**	**1,234,735**	**1,059,499**	**953,875**	**843,548**	**739,548**	**68,972,763**

Line No.	Generator	Solar Gardens (Unsubscribed)	Solar Gardens 2020 Expansion (Unsubscribed)	Solar Gardens 2020 Expansion (Unsubscribed)	Hardy Hydro Upgrade	Lake Winds Energy Park	Cross Winds Energy Park	Cross Winds Energy Park (Phase II) (unsubscribed)	Cross Winds Energy Park (Phase III) (unsubscribed)	Gratiot County Wind Farm	Crossroad Wind Farm	Heartland Wind Farm	Circuit Wind Solar	Sunfish (Unsubscribed)	Kern (Unsubscribed)	VGP_REP_2027_114.63 MW (Unsubscribed)	VGP_REP_2027_220 MW (Unsubscribed)	Spring Creek	Washington	Mustang Hills	Washtenaw	Lake Winds Energy Park Repowered	VGP_REP_2027_1 (9.42 MW)	VGP_REP_2027_223 MW	Kern (Subscribed)	Sunfish (Subscribed)
	Year	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
47	2024	277	-	-	-	113,864	151,744	-	-	179,868	365,350	227,542	271	-	-	-	-	-	-	-	-	-	-	-	-	-
48	2025	277	-	-	-	113,864	151,744	-	-	179,868	365,350	226,275	271	-	-	-	-	-	-	-	-	-	-	-	-	-
49	2026	277	2,130	-	-	113,864	151,744	-	-	179,868	365,350	227,542	271	-	-	-	-	-	77,230	263,996	-	-	-	-	-	207,060
50	2027	277	1,636	-	-	113,864	151,744	-	-	179,868	365,350	227,542	271	-	-	-	-	-	136,266	258,796	149,518	193,344	-	-	77,292	273,276
51	2028	277	836	-	-	113,864	151,744	-	-	179,868	365,350	226,275	271	-	-	-	-	-	136,135	255,495	148,998	149,868	-	307,203	309,263	78,493	279,643
52	2029	277	398	-	-	113,864	151,744	-	-	179,868	365,350	226,275	271	-	-	-	-	-	137,197	253,988	148,021	147,910	-	306,409	309,263	78,493	279,643
53	2030	277	-	2,232	-	113,864	151,744	-	-	179,868	365,350	226,275	271	-	-	-	-	-	137,197	253,988	148,021	147,910	-	306,409	309,263	78,493	279,643
54	2031	277	-	1,712	-	113,864	151,744	-	-	179,868	365,350	226,275	271	-	-	-	-	-	137,140	252,653	144,782	146,761	-	305,701	302,292	76,858	268,737
55	2032	277	-	1,216	-	113,864	151,744	-	-	179,868	365,350	226,275	271	-	-	-	-	-	137,495	253,279	149,173	147,304	-	305,211	302,701	76,854	267,200
56	2033	277	-	734	-	113,864	151,744	-	-	179,868	365,350	226,275	271	-	-	-	-	-	136,840	253,012	143,005	145,263	-	304,668	299,149	74,660	264,051
57	2034	277	-	244	-	113,864	151,744	-	-	179,868	365,350	226,367	271	-	-	-	-	-	136,688	247,741	143,007	143,962	-	303,576	299,149	74,664	263,685
58	2035	277	-	-	-	113,864	151,744	-	-	179,868	365,350	226,275	271	-	-	-	-	-	136,275	247,041	141,623	143,076	-	303,475	297,693	73,913	263,677
59	2036	277	-	-	-	113,864	151,744	-	-	179,868	365,350	226,275	-	-	-	-	-	-	136,275	247,041	141,623	143,076	-	303,475	297,693	73,913	263,677
60	2037	277	-	-	-	113,864	151,744	-	-	179,868	365,350	227,542	-	-	-	-	-	-	135,718	245,791	140,950	142,404	-	302,905	296,612	73,427	263,043
61	2038	277	-	-	-	113,864	151,744	-	-	179,868	365,350	227,542	-	-	-	-	-	-	135,091	244,680	140,318	142,075	-	302,398	295,792	73,040	258,576
62	2039	277	-	-	-	113,864	151,744	-	-	179,868	365,350	226,275	-	-	-	-	-	-	135,908	242,245	138,873	140,771	-	301,488	293,991	72,273	258,784
63	2040	277	-	-	-	113,864	151,744	-	-	179,868	365,350	226,275	-	-	-	-	-	-	135,275	240,842	138,154	140,823	-	300,865	292,966	71,985	254,226
64	2041	-	-	-	-	113,864	151,744	-	-	179,868	365,350	226,275	-	-	-	-	-	-	135,275	240,842	138,154	140,823	-	300,865	292,966	71,985	254,226
65	2042	-	-	-	-	113,864	151,744	-	-	179,868	365,350	226,367	-	-	-	-	-	-	135,386	241,038	138,254	140,934	-	300,964	293,157	72,053	254,653
66	2043	-	-	-	-	113,864	151,744	-	-	179,868	365,350	226,542	-	-	-	-	-	-	135,180	240,777	138,093	138,897	59,634	300,843	292,892	71,961	254,246
67	2044	-	-	-	-	113,864	151,744	-	-	179,868	365,350	226,817	-	-	-	-	-	-	136,066	239,336	136,770	139,606	117,710	99,908	240,060	71,274	254,663
68	2045	-	-	-	-	113,864	151,744	-	-	179,868	365,350	226,093	-	-	-	-	-	-	136,508	239,350	133,455	137,367	117,710	99,963	239,326	70,933	229,516
69	TOTAL	**4,995**	**4,910**	**6,138**	**1,300,369**	**3,336,369**	**4,576,208**	**2,024,433**	**2,867,663**	**5,439**	-	-	-	-	-	-	-	-	**2,448,410**	**4,953,323**	**3,074,489**	**3,754,980**	**1,012,763**	**5,871,404**	**3,012,363**	**1,402,400**	**5,049,017**

Line No.	Generator	REP 2020 Owned In-State Solar 200 MW	REP 2020 Owned In-State Solar 150 MW	REP 2020 Owned In-State Solar 250 MW	REP 2020 Owned In-State Solar 200 MW	REP 2021 Owned In-State Solar 250 MW	REP 2022 Owned In-State Solar 250 MW	REP 2023 Owned In-State Solar 250 MW	REP 2024 Owned In-State Solar 250 MW	REP 2025 Owned In-State Solar 100 MW	REP 2026 Owned In-State Solar 200 MW	REP 2027 Owned In-State Solar 150 MW	REP 2028 Owned In-State Solar 125 MW	REP 2029 Owned In-State Solar 62.5 MW	REP 2030 Owned In-State Solar 61.5 MW	REP 2032 Owned In-State Wind 200 MW	REP 2033 Owned In-State Wind 200 MW	REP 2034 Owned In-State Wind 200 MW	REP 2035 Owned In-State Wind 200 MW	2030 VGP REP In-State Solar 43.5 MW	2030 VGP REP In-State Solar 15.5 MW	2031 VGP REP In-State Solar 55.5 MW	2032 VGP REP In-State Solar 43.5 MW	2033 VGP REP In-State Solar 55 MW	2034 VGP REP In-State Solar 27.5 MW	2035 VGP REP In-State Solar 27.5 MW	Owned Total	GRAND TOTAL
	Year	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
70	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	818,797		**1,355,103**
71	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	872,835		**1,435,475**
72	2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,512,955		**2,114,999**
73	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,512,955		**2,155,137**
74	2028	216,131	212,836	-	-	-	-	-	-	-	-	-	-	-	118,506	-	-	-	-	-	-	-	-	-	-	-	2,158,855		**2,964,753**
75	2029	420,480	211,243	393,636	-	-	-	-	-	-	-	-	-	-	118,506	232,862	-	-	-	-	-	83,506	-	-	-	-	2,628,292		**3,994,555**
76	2030	416,580	209,790	391,426	333,198	-	-	-	-	-	-	-	-	-	118,506	232,862	232,862	-	-	-	-	82,993	76,493	-	-	-	3,426,766		**4,521,451**
77	2031	412,952	208,976	389,060	330,423	392,566	-	-	-	-	-	-	-	-	118,506	232,862	232,862	-	-	-	-	82,373	77,893	74,651	-	-	3,756,988		**5,309,528**
78	2032	409,323	207,161	386,695	327,648	390,192	384,760	-	-	-	-	-	-	-	118,506	232,862	232,862	232,862	232,862	1,760,854	-	81,753	77,893	73,251	76,248	-	4,088,600		**6,592,754**
79	2033	412,158	207,012	387,126	328,897	392,668	382,404	354,212	-	-	-	-	-	-	118,506	232,862	232,862	232,862	232,862	1,757,738	-	81,467	77,893	73,845	86,768	69,563	4,088,600		**6,986,163**
80	2034	411,406	206,646	384,846	326,612	390,381	380,126	351,857	353,668	-	-	-	-	-	118,506	232,862	232,862	232,862	232,862	1,756,867	-	81,367	76,946	73,380	86,239	68,160	4,088,600	42,958	**6,925,648**
81	2035	408,740	204,870	383,023	324,990	388,760	378,501	350,350	352,098	353,038	-	-	-	-	118,506	232,862	232,862	232,862	232,862	1,757,218	613,608	81,051	76,946	72,800	86,039	68,058	4,088,600	42,958	**7,667,173**
82	2036	407,417	203,708	381,262	323,051	386,819	376,567	348,395	350,124	351,860	351,860	-	-	-	118,506	232,862	233,776	233,776	233,776	1,753,539	613,114	80,843	76,107	72,412	85,839	67,223	4,154,610	42,277	**7,674,751**
83	2037	407,181	203,475	381,028	322,818	386,586	376,334	348,163	349,891	351,727	351,860	351,860	-	-	118,506	233,020	233,938	233,938	233,938	1,753,473	613,118	80,483	76,112	72,375	85,839	66,987	4,154,610	42,293	**7,715,445**
84	2038	407,181	203,475	381,028	322,818	386,586	376,334	348,163	349,891	351,727	351,860	351,860	349,493	-	118,506	233,020	233,938	233,938	233,938	1,753,473	613,118	80,483	76,112	72,375	85,839	66,987	4,154,610	42,293	**7,715,445**
85	2039	405,874	202,837	379,866	321,656	385,423	375,172	347,000	348,728	350,564	351,860	351,860	354,229	177,126	118,506	233,020	233,938	233,938	233,938	1,753,473	613,118	79,812	76,112	72,375	85,839	66,987	4,154,610	42,293	**7,675,498**	**11,236,041**
86	2040	398,648	199,319	376,390	318,180	382,947	372,696	344,524	346,252	348,252	349,488	349,488	352,421	176,263	118,506	233,020	233,938	233,938	233,938	1,749,883	612,531	79,251	75,025	71,328	87,626	64,548	4,154,610	42,293	**7,602,621**	**11,128,700**
87	2041	398,415	199,086	376,157	317,947	382,714	372,463	344,291	346,019	348,019	349,255	349,255	352,188	177,033	118,506	233,020	233,938	233,938	233,938	1,749,883	612,531	79,251	75,025	71,328	87,626	64,548	4,154,610	42,293	**7,602,621**	**11,328,766**
88	2042	398,415	199,086	376,157	317,947	382,714	372,463	344,291	346,019	348,019	349,255	349,255	352,351	176,376	118,506	233,020	233,938	233,938	233,938	1,749,883	612,531	79,251	75,025	71,328	87,626	64,548	4,154,610	42,293	**7,602,621**	**11,328,766**
89	2043	398,302	199,036	376,044	317,834	382,601	372,350	344,178	345,906	347,906	349,142	349,142	352,151	177,033	118,506	233,020	233,938	233,938	233,938	1,749,883	612,531	79,251	75,025	71,328	87,626	64,548	4,154,610	42,293	**7,602,621**	**11,328,766**
90	2044	398,302	199,036	376,044	317,834	382,601	372,350	344,178	345,906	347,906	349,142	349,142	352,151	176,376	118,506	233,020	233,938	233,938	233,938	1,749,883	612,531	79,251	75,025	71,328	87,626	64,548	4,154,610	42,293	**7,602,621**	**11,328,766**
91	2045	398,302	199,036	376,044	317,834	382,601	372,350	344,178	345,906	347,906	349,142	349,142	352,151	176,376	118,506	233,020	233,938	233,938	233,938	1,749,883	612,531	79,251	75,025	71,328	87,626	64,548	4,154,610	42,293	**7,602,621**	**11,328,766**
92	TOTAL	**7,176,439**	**3,873,826**	**6,797,146**	**5,875,736**	**6,585,203**	**6,017,948**	**4,655,892**	**4,153,518**	**3,838,938**	**3,452,914**	**3,345,362**	**3,033,231**	**1,231,218**	**929,798**	**2,186,417**	**2,077,824**	**2,766,852**	**3,455,881**	**15,939,735**	**5,505,324**	**15,539,735**	**5,505,324**	**15,539,735**	**5,505,324**	**15,539,735**	**5,505,324**	**139,479,498**	**199,454,260**

EAMP - Experimental Advanced Renewable Program
1 Not included in total due to customer subscriptions

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

CASE NO. U-21962
EXHIBIT A-25 (SEC-2)
PAGE 1 of 1
WITNESS: Jones
DATE: November 2024

Renewable Projected Electric Production
Off Peak Generation

Line No.	Generator	Apple Blossom	Berlin Renewable Energy	Elk Rapids Hydro.	Fremont Community Digester	Harvest II Windfarm	Heritage Gordon Windfarm I (Wind)	Heritage Gordon Windfarm I (solar)	Heritage Sheny Corners Windfarm I (NSC Phase 2)	Heritage Sheny Corners Windfarm I (NSC Phase 3)	Michigan Wind 2	North American Natural Resources (Lennon)	Scenic View Dairy (Forestville)	Scenic View Dairy (Freesoil)	WMRenewable Energy (Northern Oaks)	WMRenewable Energy (Pine Tree Acres)	Zeeland Farm Services (Fund 2)	EARP - 1.4	EARP - 5	EARP - 6	EARP - 7	EARP - 8	EARP - 9	EARP - 10	EARP - 11	EARP- Anaerobic Digester	River Park Solar	Solar Gardens 2020 Expansion (Unsubscribed)	Solar Gardens 2020 Expansion (Subscribed)	Solar Gardens 2020 Expansion (Subscribed)
	Year	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
1	2024	131,250	87,916	-	3,832	92,691	24,858	432	15,016	8,600	142,331	5,167	-	-	2,862	34,603	-	-	136	215	133	219	287	135	32	-	15,549	1,721	-	-
2	2025	131,250	87,916	-	3,832	92,691	24,858	432	15,016	8,600	142,331	5,167	-	-	2,862	34,603	-	-	136	215	133	219	287	135	32	-	86,064	1,721	-	-
3	2026	131,250	87,916	-	3,832	92,691	24,858	432	15,016	8,600	142,331	5,167	-	-	2,862	34,603	-	-	136	215	133	219	287	135	32	-	86,064	1,721	560	-
4	2027	131,250	87,916	-	3,832	92,691	24,858	432	15,016	8,600	142,331	5,167	-	-	2,862	34,603	-	-	136	202	116	247	257	185	47	-	84,877	1,721	3,148	-
5	2028	131,250	87,916	-	3,832	92,691	24,858	432	15,016	8,600	142,331	5,167	-	-	2,862	34,603	-	-	-	-	-	-	-	-	-	-	86,064	1,721	5,760	-
6	2029	131,250	87,916	-	3,832	92,691	24,858	432	15,016	8,600	142,331	5,167	-	-	2,862	34,603	-	-	-	-	-	-	-	-	-	-	86,064	1,721	8,360	-
7	2030	131,250	87,916	-	3,832	92,691	24,858	432	15,016	8,600	142,331	5,167	-	-	2,862	34,603	-	-	-	-	-	-	-	-	-	-	84,760	1,721	2,408	341
8	2031	131,250	87,916	-	3,832	92,691	24,858	624	15,016	8,600	142,331	-	-	-	-	34,603	-	-	-	-	-	-	-	-	-	-	83,279	1,721	2,784	820
9	2032	131,250	87,916	-	3,832	92,691	24,858	688	15,016	8,600	142,331	-	-	-	-	8,132	-	-	-	-	-	-	-	-	-	-	82,640	1,721	2,775	1,402
10	2033	131,250	87,916	-	215	92,691	24,858	-	15,016	8,600	142,331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	82,016	1,721	2,760	1,986
11	2034	131,250	87,916	-	-	92,691	24,858	-	15,016	8,600	142,331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	82,051	1,721	2,761	2,106
12	2035	131,250	87,916	-	-	92,691	24,858	-	15,016	8,600	142,331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81,391	1,721	2,738	2,835
13	2036	131,250	87,916	-	-	92,691	24,858	-	15,016	8,600	142,331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81,631	1,721	2,746	2,966
14	2037	131,250	87,916	-	-	92,691	24,858	-	15,016	8,600	142,331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81,631	1,721	2,746	2,966
15	2038	131,250	87,916	-	-	92,691	24,858	-	15,016	8,600	142,331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	89,659	1,721	2,988	2,736
16	2039	131,250	87,916	-	-	92,691	24,858	-	15,016	8,600	142,331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	89,659	1,721	2,992	2,767
17	2040	131,250	87,916	-	-	92,691	24,858	-	15,016	8,600	142,331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	89,659	1,721	2,993	2,767
18	2041	131,250	87,916	-	-	92,691	24,858	-	15,016	8,600	142,331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	87,966	1,721	2,936	2,696
19	2042	131,250	87,916	-	-	92,691	24,858	-	15,016	8,600	142,331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	87,966	55	2,912	2,691
20	2043	131,250	87,916	-	-	92,691	24,858	-	15,016	8,600	142,331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	86,913	-	2,946	2,655
21	2044	131,250	87,916	-	-	92,691	24,858	-	15,016	8,600	142,331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	87,042	-	2,949	2,658
22	2045	131,250	87,916	-	-	92,691	24,858	-	15,016	8,600	142,331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,949	2,658
23	TOTAL	2,625,498	1,758,322	-	32,907	2,238,974	548,842	7,277	308,424	206,266	3,131,269	36,168	-	-	49,465	265,139	-	-	545	677	416	853	1,118	405	202	-	1,833,148	35,829	48,797	37,017

Line No.	Generator	REP 2020 PPA In-State Solar 100 MW	REP 2020 PPA In-State Solar 200 MW	REP 2020 PPA In-State Solar 200 MW	REP 2021 PPA In-State Solar 200 MW	REP 2022 PPA In-State Solar 200 MW	REP 2023 PPA In-State Solar 200 MW	REP 2024 PPA In-State Solar 200 MW	REP 2025 PPA In-State Solar 200 MW	REP 2026 PPA In-State Solar 200 MW	REP 2027 PPA In-State Solar 200 MW	REP 2028 PPA In-State Solar 200 MW	REP 2029 PPA In-State Solar 125 MW	REP 2030 PPA In-State Solar 125 MW	REP 2040 PPA In-State Solar 62.5 MW	2020 VOP REP PPA In-State Solar 61.5 MW	2020 VOP REP PPA In-State Solar 18.5 MW	2021 VOP REP PPA In-State Solar 55.5 MW	2022 VOP REP PPA In-State Solar 32.5 MW	2023 VOP REP PPA In-State Solar 38 MW	2024 VOP REP PPA In-State Solar 41.5 MW	2026 VOP REP PPA In-State Solar 35 MW	REPA and Program Total
	Year	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
24	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	588,692
25	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	882,356
26	2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	881,845
27	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	881,851
28	2028	30,476	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	754,422
29	2029	76,773	153,721	-	-	-	-	-	-	-	-	-	-	-	-	36,279	-	-	-	-	-	-	947,368
30	2030	91,410	153,124	151,956	-	-	-	-	-	-	-	-	-	-	-	36,127	-	53,166	-	-	-	-	1,059,935
31	2031	91,047	153,538	151,156	-	154,057	-	-	-	-	-	-	-	-	-	35,964	-	52,930	30,392	-	-	-	1,056,757
32	2032	90,684	152,952	150,356	-	153,642	154,723	-	-	-	-	-	-	-	-	35,801	-	52,693	30,252	30,552	-	-	1,055,600
33	2033	90,321	152,366	149,556	-	153,178	152,942	153,716	-	-	-	-	-	-	-	35,638	-	52,457	30,112	30,392	26,698	-	1,049,848
34	2034	89,545	150,510	148,776	-	151,549	151,218	153,087	153,007	-	-	-	-	-	-	35,462	-	51,475	29,575	30,025	26,350	26,780	1,041,336
35	2035	88,098	148,111	148,680	-	150,628	151,437	152,186	152,954	153,723	-	-	-	-	-	35,286	-	51,235	29,435	29,881	26,631	27,236	1,041,432
36	2036	86,650	145,924	146,698	-	149,456	151,241	152,013	152,781	153,548	154,317	-	-	-	-	35,147	-	51,235	29,435	29,738	26,576	27,236	1,041,672
37	2037	87,786	147,075	147,441	-	148,658	148,779	150,140	150,908	151,673	152,436	153,204	-	-	-	34,793	-	51,415	29,536	29,596	26,376	26,861	1,040,904
38	2038	87,438	146,631	147,455	-	148,368	148,136	149,806	150,575	151,344	152,076	152,844	153,611	-	-	34,862	-	51,797	29,729	29,530	26,192	26,815	1,042,761
39	2039	87,147	146,050	146,798	-	147,867	148,136	149,101	149,873	150,611	151,410	152,179	152,716	76,858	-	34,863	-	51,849	29,759	29,570	26,032	26,677	1,041,537
40	2040	86,857	145,469	146,141	-	147,076	147,493	148,396	149,168	149,936	150,705	151,473	152,241	38,685	-	34,863	-	51,849	29,759	29,570	26,032	26,677	1,039,986
41	2041	86,407	143,138	143,901	-	144,862	145,420	146,191	146,948	147,706	148,465	149,228	152,054	76,577	37,878	33,761	31,948	50,379	28,756	27,480	26,539	17,725	1,035,192
42	2042	85,091	142,530	143,290	-	144,014	142,817	143,578	146,141	147,101	147,861	148,629	152,042	76,076	37,728	33,607	-	50,215	28,674	27,388	26,539	17,652	1,029,416
43	2043	84,139	140,615	141,724	-	142,490	140,248	141,008	143,708	144,668	145,628	146,589	149,247	76,077	37,728	33,270	-	49,486	28,363	27,075	26,768	17,481	1,008,664
44	2044	82,248	141,176	141,933	-	142,698	142,498	143,222	144,966	145,798	146,511	147,273	151,036	76,400	37,391	33,326	31,508	49,966	28,055	27,110	23,807	17,490	1,021,803
45	2045	81,578	140,016	140,825	-	141,582	140,343	141,104	143,104	143,966	144,827	145,688	149,443	75,836	37,108	33,054	31,254	49,554	28,055	26,716	23,807	17,501	1,011,718
46	TOTAL	1,188,828	2,553,629	2,390,187	3,219,773	2,476,427	1,822,890	1,797,366	1,843,129	1,886,867	1,928,614	1,971,141	1,036,558	228,386	380,054	524,425	488,150	431,136	243,235	234,168	207,856	34,269,539

Line No.	Generator	Solar Gardens (Unsubscribed)	Solar Gardens 2020 Expansion (Unsubscribed)	Solar Gardens 2020 Expansion (Unsubscribed)	Hardy Hydro Upgrade	Lake Winds Energy Park	Cross Winds Energy Park	Cross Winds Energy Park (Phase II) (unsubscribed)	Cross Winds Energy Park (Phase III) (unsubscribed)	Grabill County Wind Farm	Cresswell Wind Farm	Heartland Wind Farm	Circuit Wind Solar	Scottish (Unsubscribed)	Korn (Unsubscribed)	VOP_REP_2027_114.82 MW (Unsubscribed)	VOP_REP_2027_230 MW (Unsubscribed)	Spring Creek	Montcalm	Medaring Mills	Washtenaw	Lake Winds Energy Park Repowered	VOP_REP_2027_ 114.82 MW	VOP_REP_2027 _230 MW	Korn (Subscribed)	Scottish (Subscribed)
	Year	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
47	2024	132	-	-	-	136,797	173,148	-	-	286,471	189,396	258,693	160	-	-	-	-	-	-	-	-	-	-	-	-	-
48	2025	132	-	-	-	136,797	173,148	-	-	286,471	189,396	258,693	160	-	-	-	-	86,977	296,199	-	-	-	-	-	-	235,499
49	2026	132	2,428	-	-	136,797	173,148	-	-	286,471	189,396	258,693	160	-	-	-	-	146,231	296,682	365,803	171,102	-	-	-	88,033	313,172
50	2027	132	1,748	-	-	136,797	173,148	-	-	286,471	189,396	260,691	160	-	-	-	-	146,646	296,737	369,493	171,797	-	123,748	236,877	88,331	312,263
51	2028	132	1,056	-	-	136,797	173,148	-	-	286,471	189,396	260,691	160	-	-	-	-	147,518	292,722	367,768	170,842	-	122,921	236,280	87,418	309,321
52	2029	132	351	-	-	136,797	173,148	-	-	286,471	189,396	258,693	160	-	-	-	-	146,991	296,238	366,921	169,203	-	121,888	233,120	86,987	307,532
53	2030	132	-	2,107	-	136,797	173,148	-	-	286,471	189,396	258,693	160	-	-	-	-	146,647	295,775	366,076	169,511	-	121,275	232,937	86,987	305,993
54	2031	132	-	1,996	-	136,797	173,148	-	-	286,471	189,396	258,693	160	-	-	-	-	146,304	295,313	365,231	169,819	-	120,662	232,755	86,987	304,455
55	2032	132	-	1,884	-	136,797	173,148	-	-	286,471	189,396	258,693	160	-	-	-	-	145,961	294,851	364,386	170,128	-	120,049	232,573	86,987	302,917
56	2033	132	-	1,772	-	136,797	173,148	-	-	286,471	189,396	258,693	160	-	-	-	-	145,618	294,388	363,541	170,436	-	119,436	232,391	86,987	301,379
57	2034	132	340	-	-	136,797	173,148	-	-	286,471	189,396	258,693	160	-	-	-	-	144,880	296,196	364,991	364,934	-	119,610	229,186	85,541	302,268
58	2035	132	-	-	-	136,797	173,148	-	-	286,471	189,396	258,693	160	-	-	-	-	138,855	291,597	362,664	364,908	-	118,855	227,226	84,778	299,687
59	2036	132	-	-	-	136,797	173,148	-	-	286,471	189,396	258,693	-	-	-	-	-	141,148	290,930	362,112	363,316	-	118,263	226,127	84,262	298,627
60	2037	132	-	-	-	136,797	173,148	-	-	286,471	189,396	258,693	-	-	-	-	-	140,972	279,976	360,436	362,833	-	117,576	224,165	83,609	296,535
61	2038	132	-	-	-	136,797	173,148	-	-	286,471	189,396	258,693	-	-	-	-	-	140,127	279,396	358,555	361,777	-	116,951	222,611	83,169	293,971
62	2039	132	-	-	-	136,797	173,148	-	-	286,471	189,396	258,693	-	-	-	-	-	139,839	277,882	358,255	361,472	-	116,310	222,108	82,513	293,411
63	2040	132	-	-	-	136,797	173,148	-	-	286,471	189,396	258,693	-	-	-	-	-	139,551	277,368	357,955	361,167	-	115,669	221,605	81,857	292,851
64	2041	132	-	-	-	136,797	173,148	-	-	286,471	189,396	258,693	-	-	-	-	-	138,941	275,972	353,992	358,145	-	114,816	217,998	81,857	287,205
65	2042	2	-	-	-	136,797	173,148	-	-	286,471	189,396	258,693	-	-	-	-	-	138,152	275,691	353,145	357,298	-	113,312	216,741	80,850	285,752
66	2043	-	-	-	-	136,797	173,148	-	-	286,471	189,396	258,693	-	-	-	-	-	136,896	268,181	353,779	355,876	22,128	112,126	214,815	80,126	283,208
67	2044	-	-	-	-	136,797	173,148	-	-	286,471	189,396	258,216	-	-	-	-	-	135,972	268,597	352,393	356,372	122,768	112,987	216,521	80,391	282,101
68	2045	-	-	-	-	136,797	173,148	-	-	286,471	189,396	257,775	-	-	-	-	-	135,426	267,135	351,537	355,518	122,517	112,853	215,951	79,814	282,816
69	TOTAL	2,187	5,927	7,018	-	2,732,939	3,609,208	-	-	5,902,961	3,589,724	5,058,686	1,921	-	-	-	-	2,791,955	5,548,488	3,060,268	3,119,194	267,421	2,117,051	4,548,422	1,596,947	5,557,473

Line No.	Generator	REP 2020 Owned In-State Solar 100 MW	REP 2020 Owned In-State Solar 100 MW	REP 2020 Owned In-State Solar 200 MW	REP 2020 Owned In-State Solar 200 MW	REP 2021 Owned In-State Solar 200 MW	REP 2022 Owned In-State Solar 200 MW	REP 2023 Owned In-State Solar 200 MW	REP 2024 Owned In-State Solar 200 MW	REP 2025 Owned In-State Solar 200 MW	REP 2026 Owned In-State Solar 200 MW	REP 2027 Owned In-State Solar 200 MW	REP 2028 Owned In-State Solar 167.5 MW	REP 2028 Owned In-State Solar 125 MW	REP 2040 Owned In-State Solar 62.5 MW	REP 2020 Owned In-State Wind 300 MW	REP 2020 Owned In-State Wind 200 MW	REP 2020 Owned In-State Wind 200 MW	REP 2022 Owned In-State Wind 300 MW	REP 2024 Owned In-State Wind 400 MW	2020 VOP REP CS In-State Solar 61.5 MW	2020 VOP REP CS In-State Solar 55.5 MW	2022 VOP REP CS In-State Solar 32.5 MW	2023 VOP REP CS In-State Solar 38 MW	2024 VOP REP CS In-State Solar 41.5 MW	2026 VOP REP CS In-State Solar 35 MW	Owned Total	GRAND TOTAL
	Year	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
70	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	804,000	**1,392,692**
71	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,968,420	**2,850,776**
72	2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,968,505	**2,851,350**
73	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,736,599	**2,618,450**
74	2028	195,938	92,476	-	-	-	-	-	-	-	-	-	-	-	-	156,498	-	-	-	-	-	-	-	-	-	-	2,079,797	**2,534,309**
75	2029	193,545	91,773	193,722	-	-	-	-	-	-	-	-	-	-	-	157,832	275,992	-	-	36,278	-	-	-	-	-	-	2,076,422	**3,432,590**
76	2030	192,839	91,410	193,116	193,956	-	-	-	-	-	-	-	-	-	-	157,898	275,918	276,918	-	36,127	-	34,392	-	-	-	-	3,031,173	**4,062,308**
77	2031	192,295	91,047	192,538	193,396	192,957	-	-	-	-	-	-	-	-	-	158,007	275,516	276,516	-	35,964	-	34,392	32,392	-	-	-	3,130,957	**4,259,924**
78	2032	191,475	90,757	192,020	192,772	192,146	194,241	-	-	-	-	-	-	-	-	157,170	275,708	276,708	2,040,020	35,672	-	33,915	32,392	30,252	-	-	3,332,990	**4,663,141**
79	2033	190,654	90,321	191,202	192,148	191,335	192,942	193,736	-	-	-	-	-	-	-	156,333	275,300	276,300	2,039,778	35,380	26,698	33,438	32,392	30,252	26,698	-	3,331,023	**4,662,871**
80	2034	189,088	89,545	190,010	190,776	191,148	192,318	192,087	193,857	-	-	-	-	-	-	155,165	275,375	276,375	2,015,778	35,402	-	33,473	31,825	30,108	26,350	-	3,300,022	**4,679,776**
81	2035	186,011	88,098	188,111	188,880	190,408	191,417	192,186	192,954	193,723	-	-	-	-	-	157,832	275,992	276,992	2,007,478	1,932,656	26,350	33,273	31,636	29,965	26,631	27,236	3,695,135	**5,698,568**
82	2036	177,785	86,650	186,924	188,698	188,488	191,241	192,013	192,781	193,548	194,317	-	-	-	-	156,171	275,716	276,716	2,075,475	1,928,875	26,147	33,310	31,636	29,768	26,576	27,236	3,690,630	**5,673,685**
83	2037	175,573	87,786	187,075	187,841	188,658	189,779	190,140	190,908	191,673	192,436	193,204	-	-	-	157,532	275,088	275,588	2,060,038	1,930,275	26,732	32,821	31,208	29,576	26,376	26,861	3,682,990	**5,723,595**
84	2038	175,275	87,438	186,631	187,855	188,368	188,136	189,806	190,575	191,344	192,076	192,844	193,511	-	-	156,862	275,661	275,661	2,052,488	1,964,613	26,812	32,767	31,047	29,529	26,192	26,815	3,713,173	**5,814,935**
85	2039	174,694	87,147	186,050	186,798	187,867	188,136	189,101	189,873	190,611	191,410	192,179	192,716	76,858	-	157,863	275,339	275,339	2,046,030	1,963,803	26,812	32,569	30,869	29,179	26,032	26,677	3,708,758	**5,771,495**
86	2040	174,404	86,857	185,469	186,141	187,076	187,493	188,396	189,168	189,936	190,705	191,473	192,241	38,685	38,363	157,863	275,017	275,017	2,039,572	1,963,803	26,812	32,569	30,869	29,179	26,032	26,677	3,704,302	**5,744,288**
87	2041	172,953	86,407	183,138	183,901	184,862	185,420	186,191	186,948	187,706	188,465	189,228	192,054	76,577	37,878	156,482	273,842	273,842	2,028,938	1,954,996	23,761	31,941	30,379	28,756	27,480	26,539	3,690,088	**5,719,280**
88	2042	170,131	85,091	182,530	183,290	184,014	182,817	183,578	186,141	187,101	187,861	188,629	192,042	76,076	37,728	156,080	273,130	273,130	2,018,494	1,962,452	23,607	31,611	30,211	28,674	27,388	26,539	3,684,564	**5,711,270**
89	2043	168,278	84,139	180,975	181,724	182,490	180,248	181,008	183,708	184,668	185,628	186,589	189,247	76,077	37,728	155,327	272,376	272,376	2,005,579	1,958,333	23,270	31,481	29,873	28,363	27,075	26,768	3,671,823	**5,679,977**
90	2044	164,496	84,244	180,176	181,933	182,698	183,498	184,222	184,965	185,798	186,511	187,273	191,036	76,400	37,391	156,938	273,630	273,630	2,002,198	1,964,515	23,326	31,509	29,966	28,055	27,110	23,807	3,669,577	**5,691,380**
91	2045	163,156	83,016	178,650	179,825	181,582	180,343	181,104	183,104	183,966	184,827	185,688	189,443	75,836	37,108	156,488	273,377	273,377	2,000,216	1,960,508	23,326	31,342	29,716	28,055	26,716	23,807	3,666,264	**5,678,118**
92	TOTAL	3,056,428	1,188,828	2,553,629	2,390,187	2,238,773	2,076,427	1,822,890	1,797,366	1,843,129	1,886,867	1,928,614	1,971,141	1,036,558	228,386	2,291,966	2,274,796	2,675,375	2,196,987	2,136,168	12,272,222	399,014	314,421	380,054	431,136	365,203	34,269,539	**148,538,054**

SARP - Supercritical Advanced Renewable Program
1 Not included in total due to customer subscriptions

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

CASE NO. U-21962
EXHIBIT A-8.5(TSD-12)
PAGE 1 OF 1
witness: Zhai,Lee
DATE: November-2020

Renewable Protected Electric Production
Total Generation

Line No.	Generator	Apple Blossom	Beebe Renewable Energy	Elk Rapids Hydro.	Fremont Community Digester	Harvest I Windfarm	Heritage Gordon Windfarm (Allen)	Heritage Gordon Windfarm (Ryder)	Heritage Sheridan Wind Farm I (NEC Phase 2)	Heritage Sheridan Wind Farm I (NEC Phase 1)	Michigan Wind 2	North American Natural Resources (Lennon)	Scenic View Dairy (Farmville)	Scenic View Dairy (Freesoil)	Wildfire Renewable Energy (Northern Oaks)	Wildfire Renewable Energy (Pine Tree Acres)	Zealand Farm Services (Phase 2)	GAIP - 1.4	GAIP - 5	GAIP - 6	GAIP - 7	GAIP - 8	GAIP - 9	GAIP - 10	GAIP - 11	GAIP Anaerobic Digester	River Park Solar	Solar Gardens (Subscribed)	Solar Gardens 2020 Expansion (Subscribed)	Solar Gardens 2020 Expansion (Unsubscribed)
	Year	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
1	2008	240,990	148,478	-	14,051	274,548	47,931	-	2,664	27,861	47,699	260,201	9,677	-	-	-	5,987	64,484	-	-	484	767	484	961	1,905	401	191	84,484	5,698	-
2	2009	240,990	148,478	-	14,051	274,548	47,931	-	2,664	27,861	47,699	260,201	9,677	-	-	-	5,987	64,484	-	-	484	767	484	961	1,905	401	191	280,583	5,698	-
3	2010	240,990	148,478	-	14,051	274,548	47,931	-	2,664	27,861	47,699	260,201	9,677	-	-	-	5,987	64,484	-	-	484	767	484	961	1,905	401	191	279,681	5,698	857
4	2011	240,990	148,478	-	14,051	274,548	47,931	-	2,664	27,861	47,699	260,201	9,677	-	-	-	5,987	64,484	-	-	484	767	484	961	1,905	401	191	279,681	5,698	2,570
5	2012	240,990	148,478	-	14,051	274,548	47,931	-	2,664	27,861	47,699	260,201	9,677	-	-	-	5,987	64,484	-	-	484	767	484	961	1,905	401	191	277,784	5,698	3,284
6	2013	240,990	148,478	-	14,051	274,548	47,931	-	2,664	27,861	47,699	260,201	9,677	-	-	-	5,987	64,484	-	-	484	767	484	961	1,905	401	191	276,400	5,698	4,599
7	2014	240,990	148,478	-	14,051	274,548	47,931	-	2,664	27,861	47,699	260,201	9,677	-	-	-	4,790	64,484	-	-	-	-	-	-	-	-	-	275,400	5,698	5,198
8	2015	240,990	148,478	-	14,051	274,548	47,931	-	2,664	27,861	47,699	260,201	-	-	-	-	-	64,484	-	-	-	-	-	-	-	-	-	274,400	5,698	5,198
9	2016	240,990	148,478	-	14,051	274,548	47,931	-	2,664	27,861	47,699	260,201	-	-	-	-	-	64,484	-	-	-	-	-	-	-	-	-	274,400	5,698	4,410
10	2017	240,990	148,478	-	707	274,548	47,931	-	-	27,861	47,699	260,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274,400	5,698	3,621
11	2018	240,990	148,478	-	-	274,548	47,931	-	-	27,861	47,699	260,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274,400	5,698	2,832
12	2019	240,990	148,478	-	-	274,548	47,931	-	-	27,861	47,699	260,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274,400	5,698	2,043
13	2020	240,990	148,478	-	-	274,548	47,931	-	-	27,861	47,699	260,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274,400	5,698	1,254
14	2021	240,990	148,478	-	-	274,548	47,931	-	-	27,861	47,699	260,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274,400	5,698	465
15	2022	240,990	148,478	-	-	274,548	47,931	-	-	27,861	47,699	260,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274,400	5,698	5,198
16	2023	240,990	148,478	-	-	274,548	47,931	-	-	27,861	47,699	260,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274,400	5,698	5,198
17	2024	240,990	148,478	-	-	274,548	47,931	-	-	27,861	47,699	260,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274,400	5,698	5,198
18	2025	240,990	148,478	-	-	274,548	47,931	-	-	27,861	47,699	260,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274,400	5,698	5,198
19	2026	240,990	148,478	-	-	274,548	47,931	-	-	27,861	47,699	260,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274,400	5,698	5,198
20	2027	240,990	148,478	-	-	274,548	47,931	-	-	27,861	47,699	260,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274,400	5,698	5,198
21	2028	240,990	148,478	-	-	274,548	47,931	-	-	27,861	47,699	260,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274,400	5,698	5,198
22	2029	240,990	148,478	-	-	274,548	47,931	-	-	27,861	47,699	260,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274,400	5,698	5,198
23	2030	240,990	148,478	-	-	274,548	47,931	-	-	27,861	47,699	260,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274,400	5,698	5,198
24	2031	240,990	148,478	-	-	274,548	47,931	-	-	27,861	47,699	260,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274,400	5,698	5,198
25	TOTAL	5,539,642	3,414,000	-	108,108	6,315,000	1,101,613	-	20,564	704,629	209,208	5,724,000	67,612	-	-	-	17,123	515,208	-	-	3,872	6,136	3,872	7,701	15,240	3,208	1,528	6,427,008	131,123	69,555

Line No.	Generator	RSP 2020 PPAs in State Solar 250 MW	RSP 2020 PPAs in State Solar 250 MW	RSP 2020 PPAs in State Solar 250 MW	RSP 2021 PPAs in State Solar 250 MW	RSP 2022 PPAs in State Solar 250 MW	RSP 2023 PPAs in State Solar 250 MW	RSP 2024 PPAs in State Solar 250 MW	RSP 2025 PPAs in State Solar 250 MW	RSP 2026 PPAs in State Solar 250 MW	RSP 2027 PPAs in State Solar 250 MW	RSP 2028 PPAs in State Solar 250 MW	RSP 2029 PPAs in State Solar 250 MW	RSP 2030 PPAs in State Solar 125 MW	RSP 2031 PPAs in State Solar 62.5 MW	2032 VCP RSP PPAs in State Solar 62.5 MW	2033 VCP RSP PPAs in State Solar 62.5 MW	2034 VCP RSP PPAs in State Solar 62.5 MW	2035 VCP RSP PPAs in State Solar 62.5 MW	2036 VCP RSP PPAs in State Solar 62.5 MW	2037 VCP RSP PPAs in State Solar 62.5 MW	2038 VCP RSP PPAs in State Solar 62.5 MW	2039 VCP RSP PPAs in State Solar 62.5 MW	RENs and Projects Total
	Year	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
26	2008	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,125,321
27	2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,410,905
28	2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,414,139
29	2011	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,724,734
30	2012	325,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,034,985
31	2013	322,924	327,591	-	-	-	-	-	-	-	-	-	-	-	-	119,794	-	-	-	-	-	-	-	2,510,245
32	2014	316,281	324,134	327,559	-	-	-	-	-	-	-	-	-	-	-	119,668	112,907	-	-	-	-	-	-	2,934,358
33	2015	299,495	316,376	324,836	159,642	-	-	-	-	-	-	-	-	-	-	119,273	114,243	108,399	-	-	-	-	-	3,016,981
34	2016	296,340	314,428	324,000	159,310	326,196	-	-	-	-	-	-	-	-	-	118,244	111,889	106,178	103,051	-	-	-	-	3,068,676
35	2017	293,185	312,480	323,164	158,978	325,364	322,936	-	-	-	-	-	-	-	-	117,216	110,535	104,957	101,918	99,480	-	-	-	3,120,372
36	2018	290,030	310,532	322,328	158,646	324,532	321,872	-	-	-	-	-	-	-	-	116,188	109,181	103,736	100,785	98,355	96,930	-	-	3,172,068
37	2019	286,874	308,584	321,492	158,314	323,700	320,808	-	-	-	-	-	-	-	-	115,161	107,827	102,516	99,652	97,230	95,805	93,907	-	3,223,764
38	2020	283,719	306,636	320,656	157,982	322,868	319,744	-	-	-	-	-	-	-	-	114,133	106,473	101,295	98,519	96,105	94,681	92,783	-	3,275,460
39	2021	280,564	304,688	319,820	157,650	322,036	318,680	315,281	-	-	-	-	-	-	-	113,105	105,119	100,075	97,386	94,980	93,556	91,659	-	3,327,156
40	2022	277,408	302,740	318,984	157,318	321,204	317,616	314,417	309,936	-	-	-	-	-	-	112,077	103,765	98,855	96,253	93,855	92,432	90,535	-	3,378,852
41	2023	274,253	300,792	317,148	156,986	320,372	316,552	313,553	307,936	302,318	-	-	-	-	-	111,049	102,411	97,635	95,120	92,730	91,307	89,411	-	3,430,548
42	2024	271,097	298,844	315,312	156,654	319,540	315,488	312,689	305,936	300,636	299,936	-	-	-	-	110,021	101,057	96,415	93,986	91,605	90,183	88,287	-	3,482,244
43	2025	267,942	296,896	313,476	156,322	318,708	314,424	311,825	303,936	298,954	297,936	279,606	-	-	-	108,993	99,703	95,195	92,852	90,480	89,058	87,163	-	3,533,940
44	2026	264,786	294,948	311,640	155,990	317,876	313,360	310,961	301,936	297,272	295,936	277,988	252,986	-	-	107,965	98,349	93,975	91,719	89,355	87,934	86,039	-	3,585,636
45	2027	261,631	293,000	309,804	155,658	317,044	312,296	309,097	299,936	295,590	293,936	276,370	251,318	127,135	-	106,937	96,995	92,755	90,586	88,230	86,810	84,915	-	3,637,332
46	2028	258,475	291,052	307,968	155,326	316,212	311,232	307,233	297,936	293,908	291,936	274,752	249,651	125,567	-	105,909	95,641	91,535	89,453	87,105	85,686	83,791	-	3,689,028
47	2029	255,320	289,104	306,132	154,994	315,380	310,168	305,369	295,936	292,226	289,936	273,134	247,983	124,000	-	104,881	94,287	90,315	88,320	85,980	84,562	82,667	-	3,740,724
48	2030	252,164	287,156	304,296	154,662	314,548	309,104	303,505	293,936	290,544	287,936	271,516	246,316	122,433	-	103,853	92,933	89,095	87,186	84,855	83,438	81,543	-	3,792,420
49	2031	249,009	285,208	302,460	154,330	313,716	308,040	301,641	291,936	288,862	285,936	269,898	244,648	120,867	-	102,825	91,579	87,875	86,053	83,730	82,314	80,419	-	3,844,116

Line No.	Generator	Solar Gardens (Unsubscribed)	Solar Gardens 2020 Expansion (Unsubscribed)	Solar Gardens 2020 Expansion (Subscribed)	Hardy Hydro Upgrade	Lake Winds Energy Park	Cross Winds Energy Park	Cross Winds Energy Park (Phase II) (unsubscribed)	Cross Winds Energy Park (Phase II) (subscribed)	Gratiot County Wind Farm	Crossvant Wind Farm	Heartland Wind Farm	Circuit West Solar	Sunflish (Unsubscribed)	Kern (Unsubscribed)	VCP_RSP_2027_+100 MW (Unsubscribed)	VCP_RSP_2027_200 MW (Unsubscribed)	Spring Creek	Muskegon	Mustang Mile	Westwinse	Lake Winds Energy Park Repowered	VCP_RSP_2027_+100 MW CWW	VCP_RSP_20 27_200 MW CWW	Kern (Subscribed)	Sunflish (Subscribed) AC
	Year	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
47	2008	360	-	-	-	-	249,794	-	-	270,438	354,998	487,038	931	-	-	-	-	-	-	-	-	-	-	-	-	-
48	2009	360	-	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	-	-	-	-	-	-	-	-	-
49	2010	360	4,338	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	464,977	339,362	-	-	-	-	-	462,092	-
50	2011	360	5,186	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	479,667	353,479	347,956	351,394	-	-	-	985,093	384,497
51	2012	360	5,576	-	-	-	249,794	-	-	270,438	354,998	487,038	931	-	-	-	-	477,842	352,008	346,476	350,865	-	481,861	444,958	984,500	383,926
52	2013	360	857	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	475,767	347,904	344,528	348,365	-	484,947	446,947	983,846	378,676
53	2014	360	-	4,731	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	473,692	343,329	341,079	345,865	-	488,033	448,936	983,192	373,426
54	2015	360	-	3,678	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	472,867	342,558	339,605	343,365	-	488,983	450,925	982,539	372,176
55	2016	360	-	2,624	-	-	249,794	-	-	270,438	354,998	487,038	931	-	-	-	-	472,032	342,069	340,117	342,366	-	489,455	451,416	981,887	371,326
56	2017	360	-	1,571	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	470,548	339,755	337,631	341,367	-	489,926	452,907	981,235	368,426
57	2018	360	-	518	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	469,065	334,510	336,658	341,342	-	490,398	453,397	980,583	365,526
58	2019	360	-	-	-	-	249,794	-	-	270,438	354,998	487,038	931	-	-	-	-	467,581	333,264	335,684	340,318	-	490,869	453,888	979,931	362,626
59	2020	360	-	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	466,098	332,018	334,710	339,294	-	491,340	454,378	979,278	359,726
60	2021	360	-	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	464,614	330,772	333,736	338,270	-	491,811	454,869	978,626	356,826
61	2022	360	-	-	-	-	249,794	-	-	270,438	354,998	487,038	931	-	-	-	-	463,131	329,526	332,762	337,246	-	492,282	455,359	977,974	353,926
62	2023	360	-	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	461,647	328,280	331,788	336,222	-	492,753	455,850	977,321	351,026
63	2024	360	-	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	460,164	327,034	330,814	335,198	-	493,224	456,340	976,669	348,126
64	2025	360	-	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	458,680	325,788	329,840	334,174	-	493,695	456,831	976,017	345,226
65	2026	360	-	-	-	-	249,794	-	-	270,438	354,998	487,038	931	-	-	-	-	457,197	324,542	328,866	333,150	-	494,166	457,321	975,364	342,326
66	2027	360	-	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	455,713	323,296	327,892	332,126	-	494,637	457,812	974,712	339,426
67	2028	360	-	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	454,230	322,050	326,918	331,102	-	495,108	458,302	974,060	336,526
68	2029	360	-	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	452,746	320,804	325,944	330,078	-	495,579	458,793	973,407	333,626
69	2030	360	-	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	451,263	319,558	324,970	329,054	-	496,050	459,283	972,755	330,726
70	2031	360	-	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	449,779	318,312	323,996	328,030	-	496,521	459,774	972,103	327,826
71	2032	360	-	-	-	-	249,794	-	-	270,438	354,998	487,038	931	-	-	-	-	448,296	317,066	323,022	327,006	-	496,992	460,264	971,450	324,926
72	2033	360	-	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	446,812	315,820	322,048	325,982	-	497,463	460,755	970,798	322,026
73	2034	360	-	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	445,329	314,574	321,074	324,958	-	497,934	461,245	970,145	319,126
74	2035	360	-	-	-	-	249,794	-	-	270,438	354,998	489,605	931	-	-	-	-	443,845	313,328	320,100	323,934	-	498,405	461,736	969,493	316,226
75	TOTAL	7,924	22,512	12,527	-	4,679,224	7,487,824	-	-	8,450,457	7,629,956	10,998,428	6,276	-	-	-	-	9,424,583	6,660,003	6,704,726	7,226,423	-	9,812,648	7,861,824	9,696,498	2,436,455

Line No.	Generator	RSP 2020 Owned In State Solar 250 MW	RSP 2020 Owned In State Solar 250 MW	RSP 2020 Owned In State Solar 250 MW	RSP 2020 Owned In State Solar 250 MW	RSP 2020 Owned In State Solar 250 MW	RSP 2020 Owned In State Solar 250 MW	RSP 2020 Owned In State Solar 250 MW	RSP 2020 Owned In State Solar 250 MW	RSP 2020 Owned In State Solar 250 MW	RSP 2020 Owned In State Solar 250 MW	RSP 2017 Owned In State Solar 250 MW	RSP 2020 Owned In State Solar UP 5 MW	RSP 2020 Owned In State Solar 125 MW	RSP 2020 Owned In State Solar 62.5 MW	RSP 2020 Owned In State Wind 500 MW	RSP 2020 Owned In State Wind 250 MW	RSP 2020 Owned In State Wind 250 MW	RSP 2020 Owned In State Wind 250 MW	RSP 2020 Owned In State Wind 500 MW	2020 VCP RSP CE In State Solar 62.5 MW	2020 VCP RSP CE In State Solar 62.5 MW	2022 VCP RSP CE In State Solar 312 MW	2022 VCP RSP CE In State Solar 312 MW	2024 VCP RSP CE In State Solar 312 MW	2026 VCP RSP CE In State Solar 312 MW	Owned Total	GRAND TOTAL
	Year	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
76	2008	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,765,794	2,890,895
77	2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,691,488	4,101,393
78	2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,414,476	5,798,615
79	2011	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,162,148	6,927,306
80	2012	384,985	388,235	-	-	-	-	-	-	-	-	-	-	-	-	265,889	-	-	-	-	-	-	-	-	-	-	6,450,557	8,520,426
81	2013	382,707	385,877	387,561	-	-	-	-	-	-	-	-	-	-	-	264,515	258,629	-	-	-	337,754	-	-	-	-	-	7,739,114	10,249,359
82	2014	376,021	379,419	384,225	387,229	398,642	-	-	-	-	-	-	-	-	-	263,276	256,709	339,759	-	-	335,368	-	-	-	-	-	8,024,728	10,957,486
83	2015	358,865	366,148	381,889	384,229	396,310	399,008	-	-	-	-	-	-	-	-	261,894	254,789	336,728	338,739	-	333,382	314,992	-	-	-	-	8,304,448	11,320,429
84	2016	355,710	362,200	378,553	381,229	393,978	395,944	397,936	-	-	-	-	-	-	-	260,512	252,869	333,697	335,708	337,717	331,396	311,885	496,375	149,013	-	-	10,352,144	14,754,595
85	2017	352,554	358,252	375,217	378,229	391,646	392,880	394,872	397,936	-	396,936	-	-	-	-	259,131	250,949	330,666	332,677	334,686	329,410	309,778	492,329	147,783	95,496	-	10,399,911	18,188,284
86	2018	349,398	354,304	371,881	375,229	389,314	390,816	391,807	394,872	-	393,872	397,936	-	-	-	257,749	249,029	327,635	329,646	331,655	326,424	307,671	488,283	146,553	94,554	95,120	10,447,675	22,610,954
87	2019	347,764	350,476	368,545	372,229	386,982	388,752	389,743	391,808	397,936	390,808	394,872	-	-	-	256,366	247,109	324,604	326,615	328,624	323,438	305,564	484,237	145,323	93,612	94,189	10,495,438	26,725,247
88	2020	346,129	348,648	366,209	369,229	384,650	386,688	387,679	389,744	395,872	388,744	392,808	779,666	252,992	-	254,983	245,189	321,573	323,584	325,593	320,452	303,457	480,191	144,093	92,670	93,258	10,543,199	30,767,447
89	2021	344,494	346,820	363,873	366,229	382,318	384,624	385,615	387,680	393,808	386,680	390,744	775,338	251,693	127,135	253,599	243,269	318,542	320,553	322,562	317,466	301,350	476,145	142,863	91,728	92,327	10,591,066	34,808,513
90	2022	342,859	344,992	361,537	363,229	379,986	382,560	383,551	385,616	391,744	384,616	388,680	770,990	250,394	125,567	252,216	241,349	315,511	317,522	319,531	314,480	299,243	472,099	141,633	90,786	91,396	10,638,933	38,849,446
91	2023	341,224	343,164	359,201	360,229	377,654	380,496	381,487	383,552	389,680	382,552	386,616	766,642	249,095	124,000	250,832	239,429	312,480	314,491	316,500	311,494	297,136	468,053	140,403	89,844	90,465	10,686,867	42,890,313
92	2024	339,589	341,336	356,865	357,229	375,322	378,432	379,423	381,488	387,616	380,488	384,552	762,294	247,796	122,433	249,449	237,509	309,448	311,460	313,469	308,508	295,029	464,007	139,173	88,902	89,534	10,734,800	46,930,180
93	2025	337,954	339,508	354,529	354,229	372,990	376,368	377,359	379,424	385,552	378,424	382,488	757,946	246,497	121,301	248,066	235,589	306,417	308,429	310,438	305,522	292,922	459,961	137,943	87,960	88,603	10,782,733	50,969,913
94	2026	336,319	337,680	352,193	351,229	370,658	374,304	375,295	377,360	383,488	376,360	380,424	753,598	245,198	120,168	246,683	233,669	303,385	305,398	307,406	302,536	290,815	455,915	136,713	87,018	87,672	10,830,666	55,009,646
95	2027	334,684	335,852	349,857	348,229	368,326	372,240	373,231	375,296	381,424	374,296	378,360	749,250	243,899	119,035	245,299	231,749	300,354	302,367	304,375	299,550	288,708	451,869	135,483	86,076	86,741	10,878,599	59,049,379
96	2028	333,049	334,024	347,521	345,229	366,994	370,176	371,167	373,232	379,360	372,232	376,296	744,902	242,600	117,903	243,916	229,829	297,323	299,336	301,344	296,564	286,601	447,823	134,253	85,134	85,810	10,926,532	63,089,112
97	2029	331,414	332,196	345,185	342,229	365,662	368,112	369,103	371,168	377,296	370,168	374,232	740,554	241,301	116,771	242,532	227,909	294,291	296,305	298,313	293,578	284,494	443,777	133,023	84,192	84,879	10,974,465	67,128,845
98	2030	329,779	330,368	342,849	339,229	364,330	366,048	367,039	369,104	375,232	368,104	372,168	736,206	240,002	115,639	241,149	226,089	291,260	293,274	295,282	290,592	282,387	439,731	131,793	83,250	83,948	11,022,398	71,168,578
99	2031	328,144	328,540	340,513	336,229	362,998	363,984	364,975	367,040	373,168	365,040	370,104	731,858	238,703	114,506	239,766	224,269	288,229	290,243	292,251	287,606	280,280	435,685	130,563	82,308	83,017	11,070,331	75,208,311
100	2032	326,509	326,712	338,177	333,229	361,666	361,920	362,911	365,040	371,104	362,976	368,040	727,510	237,404	113,374	238,383	222,449	285,198	287,212	289,220	284,620	278,173	431,639	129,333	81,366	82,086	11,118,264	79,247,575
101	2033	324,874	324,884	335,841	330,229	360,334	359,856	360,847	362,976	369,040	360,912	366,976	723,162	236,105	112,241	236,999	220,629	282,167	284,181	286,189	281,634	276,066	427,593	128,103	80,424	81,155	11,166,197	83,287,843
102	2034	323,239	323,056	333,505	327,229	359,002	357,792	358,783	360,912	367,976	358,848	364,912	718,814	234,806	111,108	235,616	218,809	279,136	281,150	283,158	278,648	273,959	423,547	126,873	79,482	80,224	11,214,130	87,328,109
103	2035	321,604	321,228	331,169	324,229	357,670	355,728	356,719	358,848	365,912	356,784	362,848	714,466	233,507	109,975	234,233	217,189	276,105	278,119	280,127	275,662	271,852	419,501	125,643	78,540	79,293	11,262,062	91,368,375
104	2036	319,969	319,400	328,833	321,229	356,338	353,664	354,655	356,784	363,848	354,720	360,784	710,118	232,208	108,842	232,849	215,569

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

CASE NO.: U-21962
EXHIBIT: A-27 (SBC-4)
PAGE: 1 of 1
WITNESS: SBCollier
DATE: November 2024

Renewable Energy Plan Projected Capped Transfer Costs

Line No.	(a)	(b1)	(b)	(b8)	(c)	(d)	(e)	(f1)	(g)	(g1)	(h)	(i)	(j)	(j1)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)	(aa)	(ab)	(ac)
	Generator	Apple Blossom	Beebe Renewable Energy	Elk Rapids Hydro.	Fremont Community Digester	Harvest II Windfarm	Heritage Gordon Windfarm I (Wind)	Heritage Gordon Windfarm I (solar)	Heritage Stoney Corners Windfarm I (MEC Phase 2)	Heritage Stoney Corners Windfarm I (MEC Phase 3)	Michigan Wind 2	North American Natural Resources (Lennon)	Scenic View Dairy (Pennville)	Scenic View Dairy (Freeport)	WMRenewable Energy (Northern Oaks)	WMRenewable Energy (Pine Tree Acres)	Zeeland Farm Services (Plant 2)	SABP- 1-4	SABP-5	SABP-6	SABP-7	SABP-8	SABP-9	SABP-10	SABP-11	SABP-Anaerobic Digester	River Park Solar	Solar Gardens (Unbundled)	Solar Gardens 2020 Expansion (Unbundled)	Solar Gardens 2020 Expansion (Bundled)
	Year	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
1	2014	15,795,738	39,334,614	-	1,690,209	19,131,631	5,482,805	309,384	3,172,339	2,272,490	27,316,658	802,908	-	-	248,199	7,918,378	-	-	31,163	63,438	36,095	57,837	61,208	30,084	14,628	-	3,993,664	260,668	-	-
2	2015	15,795,738	35,248,733	-	1,256,720	18,973,114	5,126,868	290,038	2,943,016	1,908,954	28,398,693	699,913	-	-	326,033	7,208,055	-	-	52,786	64,018	36,653	58,771	83,208	33,242	14,962	-	7,165,420	276,752	-	-
3	2016	15,795,738	35,033,038	-	1,256,695	18,997,038	5,332,408	303,408	3,030,703	2,080,398	28,645,661	688,398	-	-	325,135	7,287,198	-	-	54,861	65,595	36,226	58,708	85,391	36,268	15,428	-	7,267,878	286,738	39,781	-
4	2017	15,795,738	35,248,733	-	1,256,695	21,434,277	5,426,111	312,427	3,172,407	2,280,775	28,398,693	967,000	-	-	324,135	7,287,198	-	-	51,878	58,756	32,832	52,752	78,347	32,938	14,287	-	7,432,537	296,800	80,053	-
5	2018	15,795,738	35,248,733	-	1,256,695	21,434,277	5,426,111	312,427	3,172,407	2,280,775	28,398,693	967,000	-	-	324,135	8,054,432	-	-	-	-	-	-	-	-	-	-	7,432,537	296,800	142,063	-
6	2019	15,795,738	35,123,225	-	1,256,807	22,612,455	5,120,238	348,553	3,168,014	2,288,950	33,007,002	822,990	-	-	256,658	8,377,424	-	-	-	-	-	-	-	-	-	-	7,955,764	232,889	109,816	-
7	2020	15,795,738	32,626,430	-	1,256,798	23,094,199	5,237,870	353,270	3,181,187	2,198,503	34,513,150	830,905	-	-	259,496	8,502,577	-	-	-	-	-	-	-	-	-	-	7,757,960	236,931	187,869	37,795
8	2021	15,795,738	35,148,327	-	1,256,792	23,675,897	5,388,327	365,738	3,658,761	2,398,402	35,313,718	-	-	-	-	8,735,139	-	-	-	-	-	-	-	-	-	-	7,622,060	238,212	189,850	37,835
9	2022	15,795,738	35,296,736	-	1,169,652	23,712,277	5,407,202	367,366	3,679,662	2,410,796	35,452,496	-	-	-	-	2,396,437	-	-	-	-	-	-	-	-	-	-	7,658,096	239,539	183,982	36,732
10	2023	15,795,738	35,539,960	-	36,490	23,945,450	5,499,002	-	3,714,016	2,455,975	35,790,587	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,054,336	244,264	188,910	142,095
11	2024	15,795,738	35,997,161	-	-	24,364,993	5,707,026	-	3,764,036	2,497,098	36,290,600	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,172,136	236,280	202,068	147,215
12	2025	15,795,738	36,454,586	-	-	24,793,993	5,915,026	-	3,814,036	2,538,222	36,790,600	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,290,136	248,320	215,268	157,215
13	2026	15,795,738	37,012,245	-	-	25,222,493	6,042,685	-	3,839,425	2,576,475	37,000,641	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,408,595	248,320	212,683	158,795
14	2027	15,795,738	37,597,272	-	-	25,868,648	6,086,141	-	4,012,209	2,603,038	38,676,635	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,536,145	254,104	233,671	223,165
15	2028	15,795,738	38,185,424	-	-	26,233,805	7,128,934	-	4,099,612	3,688,660	39,026,542	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,660,718	261,701	233,013	227,750
16	2029	15,795,738	38,800,482	-	-	26,998,787	7,296,600	-	4,188,177	2,756,755	40,362,986	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,786,926	271,108	227,103	235,038
17	2030	15,795,738	38,428,647	-	-	27,578,112	7,450,207	-	4,279,964	3,893,805	41,272,024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,918,631	280,490	226,327	243,128
18	2031	15,795,738	38,310,788	-	-	28,171,633	7,612,127	-	4,375,439	3,992,138	42,139,556	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9,052,418	286,140	226,220	248,487
19	2032	15,795,738	38,192,929	-	-	28,775,154	7,777,048	-	4,472,914	4,091,471	43,007,088	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9,187,204	8,712	226,113	253,845
20	2033	15,795,738	38,364,672	-	-	29,400,408	7,944,410	-	4,573,081	4,188,015	43,906,647	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9,336,000	-	226,076	259,278
21	2034	15,795,738	32,646,138	-	-	30,033,847	8,116,964	-	4,658,351	3,552,185	42,803,721	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,056,766	-	226,023	258,532
22	2035	15,795,738	32,726,103	-	-	30,679,573	8,296,598	-	4,759,028	3,629,133	43,889,141	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	222,283	263,423
23	TOTAL	236,935,780	588,688,488	-	12,729,337	504,210,955	147,641,798	3,914,222	84,788,791	59,798,615	833,723,023	6,387,367	-	-	3,402,630	85,637,883	-	-	391,889	313,507	139,772	231,028	309,003	135,532	59,305	-	164,057,728	4,493,399	3,960,261	3,137,386

Line No.	(ae)	(af)	(ag)	(ah)	(ai)	(aj)	(ak)	(al)	(am)	(an)	(ao)	(ap)	(aq)	(ar)	(as)	(at)	(au)	(av)	(aw)	(ax)	(ay)	(az)	(ba)	(bb)	(bc)	(bd)
	Generator	REP 2020 PPA In-State Solar 100 MW	REP 2020 PPA In-State Solar 200 MW	REP 2020 PPA In-State Solar 300 MW	REP 2021 PPA In-State Solar 200 MW	REP 2022 PPA In-State Solar 200 MW	REP 2023 PPA In-State Solar 200 MW	REP 2024 PPA In-State Solar 200 MW	REP 2025 PPA In-State Solar 200 MW	REP 2026 PPA In-State Solar 200 MW	REP 2027 PPA In-State Solar 200 MW	REP 2028 PPA In-State Solar 327.5 MW	REP 2029 PPA In-State Solar 125 MW	REP 2030 PPA In-State Solar 62.5 MW	REP 2031 PPA In-State Solar 62.5 MW	2020 VGP-REP PPA In-State Solar 14.5 MW	2021 VGP-REP PPA In-State Solar 26.1 MW	2022 VGP-REP PPA In-State Solar 41.5 MW	2023 VGP-REP PPA In-State Solar 10 MW	2024 VGP-REP PPA In-State Solar 41.5 MW	2025 VGP-REP PPA In-State Solar 12 MW	REPA and Program Total
	Year	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
24	2014																						320,372,988
25	2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	326,123,429
26	2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	329,551,275
27	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	332,446,487
28	2018	19,753,335																					335,446,487
29	2019	19,853,168	33,128,096	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	335,775,956
30	2020	19,952,670	33,128,003	34,209,383	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	333,963,989
31	2021	19,968,327	33,128,003	34,209,383	34,697,296	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	337,585,485
32	2022	19,983,212	33,128,008	34,203,961	34,690,837	35,893,087	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	337,422,527
33	2023	19,333,198	32,894,903	33,772,363	34,676,450	35,893,750	36,703,980	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	332,935,391
34	2024	19,347,060	32,429,464	-	34,139,180	35,893,750	36,703,980	37,512,899	-	-	-	-	-	-	-	-	-	-	-	-	-	-	326,967,285
35	2025	19,360,921	32,429,464	-	34,139,180	34,693,750	36,146,473	37,149,688	38,117,349	-	-	-	-	-	-	-	-	-	-	-	-	-	326,967,405
36	2026	19,374,782	32,429,464	-	34,139,180	34,693,750	36,146,473	36,678,969	37,658,837	38,671,796	-	-	-	-	-	-	-	-	-	-	-	-	327,234,248
37	2027	19,388,644	32,296,532	33,123,902	34,012,275	33,493,750	35,589,342	36,833,125	37,654,777	38,614,988	39,658,085	-	-	-	-	-	-	-	-	-	-	-	328,363,455
38	2028	19,758,560	32,032,330	32,814,489	33,798,002	33,758,542	35,837,008	36,992,179	37,571,750	38,578,488	39,657,017	10,455,960	-	-	-	-	-	-	-	-	-	-	328,471,743
39	2029	18,928,777	31,888,036	32,703,751	33,632,602	34,028,276	35,499,498	36,606,938	37,361,602	38,392,498	39,608,805	39,589,193	20,776,705	-	-	-	-	-	-	-	-	-	325,208,339
40	2030	18,952,689	31,756,934	32,613,460	33,488,938	34,390,845	35,329,374	36,221,698	37,208,012	38,233,738	39,252,121	39,355,375	39,663,844	10,432,042	-	-	-	-	-	-	-	-	321,860,862
41	2031	18,933,798	31,672,827	32,527,908	33,450,608	34,354,257	35,237,171	36,173,553	37,105,144	38,142,437	39,143,580	39,318,765	39,643,688	32,597,486	-	-	-	-	-	-	-	-	321,457,867
42	2032	18,914,907	31,588,921	32,442,357	33,412,277	34,317,669	35,144,969	36,125,408	37,001,276	38,051,176	39,034,039	39,282,155	39,623,532	32,531,375	-	-	-	-	-	-	-	-	320,872,054
43	2033	18,896,015	31,433,388	32,272,352	33,126,278	34,039,848	34,957,967	35,888,622	36,842,862	37,854,209	38,842,662	39,246,432	39,603,532	32,531,375	-	-	-	-	-	-	-	-	320,334,883
44	2034	18,272,757	31,296,126	32,127,133	32,986,575	33,897,988	34,820,184	35,765,642	36,703,093	37,690,432	38,753,418	39,908,906	20,604,338	10,475,476	-	-	-	-	-	-	-	-	320,977,921
45	2035	18,191,128	31,028,332	31,859,383	32,718,335	33,617,818	34,529,947	35,457,772	36,373,727	37,358,218	38,373,388	39,518,658	20,533,658	10,396,336	-	-	-	-	-	-	-	-	320,308,105
46	TOTAL	348,230,438	548,688,581	529,013,973	507,478,385	493,645,496	481,858,438	458,739,523	410,120,204	381,970,698	352,394,218	305,031,988	143,779,308	85,145,180	-	-	-	-	-	-	-	-	7,033,762,383

Line No.	(be)	(bf)	(bg)	(bh)	(bi)	(bj)	(bk)	(bl)	(bm)	(bn)	(bo)	(bp)	(bq)	(br)	(bs)	(bt)	(bu)	(bv)	(bw)	(bx)	(by)	(bz)	(ca)	(cb)	(cc)	(cd)
	Generator	Solar Gardens (Unbundled)	Solar Gardens 2020 Expansion (Unbundled)	Solar Gardens 2020 Expansion (Unbundled)	Nordy Hydro Upgrade	Lake Winds Energy Park	Cross Winds Energy Park	Cross Winds Energy Park (Phase II) (unsubscribed)	Cross Winds Energy Park (Phase III) (unsubscribed)	Gratiot County Wind Farm	Cresent Wind Farm	Heartland Wind Farm	Cloud Ved Solar	Suffolk (Unbundled)	Kore (Unbundled)	VGP_REP_2027_110.92 MW (Unbundled)	VGP_REP_2027_220 MW (Unbundled)	Spring Creek	Muskegon	Waiting Mile	Washtenaw	Lake Winds Energy Park Repowered	VGP_REP_2027_110.92 MW	VGP_REP_2027_220 MW	Harris (Subscribed)	Suffolk (Subscribed)
	Year	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
47	2014	22,383			-	28,580,876	28,175,398		-	35,739,170	27,085,718	21,802,980	45,349													
48	2015	22,037			-	28,874,882	28,710,836		-	32,408,508	27,657,660	21,803,343	46,199	-	-	-	-	-					-	-	-	-
49	2016	22,027	388,868		-	29,870,618	27,198,376		-	32,948,870	28,062,211	22,846,908	46,959	-	-	-	-	22,762,420	36,483,854				-	-	-	-
50	2017	22,027	223,774		-	30,301,368	27,453,348		-	32,147,106	28,062,211	22,846,908	46,959	-	-	-	-	18,477,558	37,763,989	21,617,627	31,400,538		-	-	-	-
51	2018	22,027	137,738		-	34,201,862	27,453,348		-	32,147,106	28,062,211	22,846,908	46,547	-	-	-	-	18,367,656	36,477,701	20,063,198	32,550,687		-	-	-	-
52	2019	18,373	36,535		-	33,533,228	26,479,996		-	31,336,532	28,668,158	22,846,908	46,473	10,588	-	-	-	20,510,216	36,869,867	20,023,575	32,548,837		-	-	-	-
53	2020	18,640		302,302	-	36,550,597	26,064,256		-	30,595,520	30,093,870	27,422,760	51,439	-	-	-	-	19,806,438	39,429,660	20,598,955	30,997,930		-	-	-	-
54	2021	27,828		371,820	-	37,661,437	26,758,596		-	30,595,130	31,328,608	28,131,403	53,539	-	-	-	-	20,388,312	40,980,677	20,998,532	31,279,993		-	-	-	-
55	2022	28,448		388,978	-	37,663,275	26,538,123		-	37,653,487	31,923,976	28,927,303	53,878	-	-	-	-	20,163,966	40,823,966	23,653,135	31,734,470		-	-	-	-
56	2023	28,278		373,973	-	38,700,655	26,554,459		-	36,486,492	32,813,477	28,965,663	54,877	-	-	-	-	20,403,490	41,386,676	24,723,248	32,248,698		-	-	-	-
57	2024	20,136		42,963	-	27,276,990	18,168,603		-	28,396,778	17,030,234	25,763,953	38,011	-	-	-	-	15,349,943	27,890,454	21,965,145	27,458,133		-	-	-	-
58	2025	20,136			-	27,276,990	18,168,603		-	28,396,778	17,030,234	25,763,953	37,243	-	-	-	-	15,349,943	27,890,454	21,965,145	27,458,133		-	-	-	-
59	2026	20,136			-	27,276,990	18,168,603		-	28,396,778	17,030,234	25,763,953		-	-	-	-	15,362,918	27,904,461	21,797,086	27,510,532		-	-	-	-
60	2027	42,766			-	27,276,990	18,168,603		-	28,396,778	17,030,234	25,763,953	-	-	-	-	-	14,862,242	27,077,560	21,624,115	27,393,672		-	-	-	-
61	2028	22,687			-	27,276,990	18,168,603		-	28,396,778	17,030,234	25,763,953	-	-	-	-	-	14,863,275	26,903,775	21,510,120	27,350,176		-	-	-	-
62	2029	42,628			-	27,276,990	18,168,603		-	28,396,778	17,030,234	25,763,953	-	-	-	-	-	14,863,188	26,790,511	21,396,588	27,308,688		-	-	-	-
63	2030	20,568			-	27,276,990	18,168,603		-	28,396,778	17,030,234	25,763,953	-	-	-	-	-	14,863,188	26,700,253	21,313,108	27,136,088		-	-	-	-
64	2031	20,570			-	27,276,990	18,168,603		-	28,396,778	17,030,234	25,763,953	-	-	-	-	-	12,610,776	26,501,963	21,168,698	27,037,730		-	-	-	-
65	2032	738			-	27,276,990	18,168,603		-	28,396,778	17,030,234	25,763,953	-	-	-	-	-	12,610,776	26,501,963	21,168,698	27,037,730		-	-	-	-
66	2033	-			-	24,951,290	18,168,603		-	28,396,778	17,030,234	25,763,953	-	-	-	-	-	14,857,440	26,251,453	20,963,298	26,930,730	3,387,875	-	-	-	-
67	2034	-			-		18,168,603		-	28,396,778	17,030,234	25,763,953	-	-	-	-	-	14,857,792	26,345,423	20,684,514	26,798,090	18,322,451	-	-	-	-
68	2035	-			-		18,168,603		-	28,396,778	17,030,234	25,763,953	-	-	-	-	-	14,729,111	25,920,902	20,713,603	26,653,178	28,575,262	-	-	-	-
69	TOTAL	756,639	786,992	1,557,311	-	614,655,676	514,188,432	-	-	582,238,128	383,238,797	863,052,262	611,864	-	-	-	-	327,916,536	633,984,129	414,604,427	386,792,189	21,379,701	-	-	-	-

Line No.	(ce)	(cf)	(cg)	(ch)	(ci)	(cj)	(ck)	(cl)	(cm)	(cn)	(co)	(cp)	(cq)	(cr)	(cs)	(ct)	(cu)	(cv)	(cw)	(cx)	(cy)	(cz)	(da)	(db)	(dc)	(dd)	(de)	(df)
	Generator	HP 2025 Owned In-State Solar 300 MW	REP 2020 Owned In-State Solar 100 MW	REP 2020 Owned In-State Solar 200 MW	REP 2020 Owned In-State Solar 300 MW	REP 2021 Owned In-State Solar 200 MW	REP 2022 Owned In-State Solar 200 MW	REP 2023 Owned In-State Solar 200 MW	REP 2024 Owned In-State Solar 200 MW	REP 2025 Owned In-State Solar 200 MW	REP 2026 Owned In-State Solar 200 MW	REP 2027 Owned In-State Solar 200 MW	REP 2028 Owned In-State Solar 327.5 MW	REP 2029 Owned In-State Solar 125 MW	REP 2030 Owned In-State Solar 62.5 MW	REP 2031 Owned In-State Solar 62.5 MW	REP 2020 Owned In-State Wind 100 MW	REP 2020 Owned In-State Wind 200 MW	REP 2020 Owned In-State Wind 300 MW	REP 2022 Owned In-State Wind 200 MW	REP 2023 Owned In-State Wind 200 MW	2029 VGP-REP CE In-State Solar 61.5 MW	2030 VGP-REP CE In-State Solar 16.5 MW	2031 VGP-REP CE In-State Solar 16.5 MW	2032 VGP-REP CE In-State Solar 12.5 MW	VGP-REP CE In-State Solar 67.5 MW	2034 VGP-REP CE In-State Solar 67.5 MW	2035 VGP-REP CE In-State Solar 22 MW	Owned Total	GRAND TOTAL
	Year	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
70	2014																													320,848,336	640,834,973
71	2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	326,897,429	653,797,858
72	2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	329,972,540	659,180,815
73	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	332,601,252	665,751,711
74	2018	25,360,667	21,276,192	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17,799,530	-	-	-	-	-	-	-	-	-	-	-	337,976,336	668,165,899
75	2019	25,452,672	21,402,208	35,992,987	-	-	-	-	-	-	-	-	-	-	-	-	-	18,312,900	38,023,985	-	-	-	-	-	-	-	-	-	-	333,433,848	669,292,843
76	2020	25,976,833	21,786,311	36,492,200	38,476,608	-	-	-	-	-	-	-	-	-	-	-	-	18,386,386	38,766,536	38,766,536	-	-	-	-	-	-	-	-	-	329,216,587	717,176,576
77	2021	26,003,128	22,123,340	37,858,262	37,243,377	37,476,711	-	-	-	-	-	-	-	-	-	-	-	18,750,607	37,666,842	37,666,842	-	-	-	-	-	-	-	-	-	322,238,766	700,649,266
78	2022	26,029,588	22,555,600	37,825,207	36,637,216	36,229,323	36,423,438	-	-	-	-	-	-	-	-	-	-	18,296,858	38,412,804	38,412,804	38,669,873	-	-	-	-	-	-	-	-	321,226,342	1,249,622,666
79	2023	25,556,048	22,555,600	37,825,207	36,622,216	36,229,323	36,423,438	28,393,693	-	-	-	-	-	-	-	-	-	18,296,858	38,412,804	38,412,804	38,669,873	3,387,875	-	-	-	-	-	-	-	321,226,342	1,242,161,391
80	2024	25,556,048	22,556,600	37,556,262	36,496,628	37,473,649	36,679,821	28,553,693	39,972,012	-	-	-	-	-	-	-	-	18,296,857	38,755,727	38,406,212	38,336,868	-	-	-	-	-	-	-	-	321,226,342	1,233,202,050
81	2025	25,556,048	22,556,600	37,556,262	36,496,628	36,793,317	36,679,821	28,553,693	39,972,012	40,938,392	-	-	-	-	-	-	-	18,296,857	38,755,727	38,406,212	38,336,868	130,961,131	-	-	-	-	-	-	-	321,226,342	1,241,086,368
82	2026	25,556,048	22,556,600	37,556,262	36,496,628	36,793,317	36,679,821	28,553,693	39,972,012	40,938,392	41,788,655	-	-	-	-	-	-	18,133,136	38,615,350	38,538,676	38,336,868	131,439,593	-	-	-	-	-	-	-	318,113,216	1,233,847,798
83	2027	25,972,432	22,556,600	37,556,262	36,496,628	36,793,317	36,679,821	27,960,602	39,972,012	40,938,392	41,788,655	42,897,388	-	-	-	-	-	18,096,237	38,608,303	38,427,231	38,301,861	130,964,032	-	-	-	-	-	-	-	1,035,836,738	1,066,664,363
84	2028	26,518,276	22,556,600	37,556,262	36,496,628	36,793,317	36,679,821	27,960,602	39,972,012	40,938,392	41,788,655	42,897,388	32,676,715	-	-	-	-	18,096,536	38,768,903	38,428,136	38,279,649	130,873,305	-	-	-	-	-	-	-	1,066,800,802	1,066,821,903
85	2029	26,888,968	22,556,600	37,556,262	36,496,628	36,793,317	36,679,821	27,960,602	39,972,012	40,938,392	41,788,655	42,897,388	32,676,715	22,256,773	-	-	-	18,096,501	38,765,357	38,428,088	38,241,256	130,868,543	-	-	-	-	-	-	-	1,066,836,602	1,066,172,790
86	2030	26,888,968	22,556,600	37,556,262	36,496,628	36,793,317	36,679,821	27,960,602	39,972,012	40,938,392	41,788,655	42,897,388	32,676,715	22,256,773	11,378,830	-	-	18,096,501	38,765,357	38,428,088	38,241,256	130,868,543	-	-	-	-	-	-	-	1,066,836,602	1,066,172,790
87	2031	26,927,275	22,556,600	37,556,262	36,496,628	36,793,317	36,679,821	27,960,602	39,972,012	40,938,392	41,788,655	42,897,388	32,676,715	22,256,773	11,378,830	11,378,830	-	18,096,708	38,853,209	38,420,308	38,202,898	130,853,208	-	-	-	-	-	-	-	1,066,179,140	1,057,812,127
88	2032	26,975,728	22,556,600	37,556,262	36,496,628	36,793,317	36,679,821	27,960,602	39,972,012	40,938,392	41,788,655	42,897,388	32,676,715	22,256,773	11,378,830	11,378,830	11,410,236	18,096,187	38,853,093	38,420,308	38,202,898	130,853,208	-	-	-	-	-	-	-	1,066,845,876	1,024,238,647
89	2033	26,958,606	22,556,600	37,556,262	36,496,628	36,793,317	36,679,821	27,960,602	39,972,012	40,938,392	41,788,655	42,897,388	32,676,715	22,256,773	11,378,830	11,378,830	11,410,236	18,096,212	38,760,302	38,420,308	38,202,898	130,868,608	-	-	-	-	-	-	-	1,066,801,540	1,020,238,436
90	2034	26,754,870	22,556,600	37,556,262	36,496,628	36,793,317	36,679,821	27,960,602	39,972,012	40,938,392	41,788,655	42,897,388	32,676,715	22,256,773	11,378,830	11,378,830	11,410,236	18,096,376	38,760,302	38,420,308	38,202,898	130,868,608	-	-	-	-	-	-	-	1,066,800,540	1,013,936,868
91	2035	26,653,988	22,556,600	37,556,262	36,496,628	36,793,317	36,679,821	27,960,602	39,972,012	40,938,392	41,788,655	42,897,388	32,676,715	22,256,773	11,378,830	11,378,830	11,410,236	18,096,376	38,760,302	38,420,308	38,202,898	130,868,608	-	-	-	-	-	-	-	1,066,800,540	1,003,921,195
92	TOTAL	730,476,279	375,010,396	601,852,021	577,482,939	562,864,555	527,603,933	501,609,119	674,139,393	680,295,698	414,603,642	382,253,301	260,603,139	156,556,375	68,273,480	68,273,480	33,230,708	333,837,143	385,306,431	1,347,709,884	1,403,192,375	-	-	-	-	-	-	-	36,860,476,936	32,477,230,055

SABP - Experimental Advanced Renewable Program

MICHIGAN PUBLIC SERVICE COMMISSION
Proceeding Exhibit Protocol

CASE NO.: U-21962
EXHIBIT: A-8.5 (TSD-12)
PAGE: 1 of 1
WITNESS: ZICoke
PARTY: Staff (MPSC)

Renewable Energy Plan Transfer Price Limits

Line No.	Generator	Apple Blossom	Beebe Renewable Energy	Elk Rapids Hydro.	Fremont Community Digester	Harvest II Windfarm	Heritage Garden Windfarm I (Wind)	Heritage Garden Windfarm I (solar)	Heritage Sisney Corners Windfarm I (MEC Phase 2)	Heritage Sisney Corners Windfarm I (MEC Phase 3)	Michigan Wind 2	North American Natural Resources (Lawson)	Scenic View Dairy (Fennville)	Scenic View Dairy (Freesoil)	WM/Renewable Energy (Northern Data)	WM/Renewable Energy (Pine Tree Acres)	Zeeland Farm Services (Fund 2)	SAMP - 1-4	SAMP-5	SAMP-6	SAMP-7	SAMP-8	SAMP-9	SAMP-10	SAMP-11	SAMP-Anaerobic Digester	River Park Solar	Solar Gardens (Subscribed)	Solar Gardens 2020 Expansion (Subscribed)
	Year	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
1	2024	10,763,718	19,314,624	-	2,079,014	18,121,021	6,143,691	531,261	3,356,437	2,339,937	27,135,658	632,908	-	-	-	-869,369	7,918,376	-	-	51,580	123,485	80,291	-	103,898	167,738	17,117	26,611	-	########	202,898	-
2	2025	10,763,718	19,749,701	-	1,872,963	19,971,114	6,379,624	515,963	7,066,591	7,066,591	28,566,000	638,916	-	-	-	315,008	8,125,140	-	-	51,580	123,485	80,291	-	103,898	167,738	17,117	26,611	-	########	204,906	-
3	2026	10,763,718	21,312,142	-	2,168,323	19,967,339	6,571,389	522,453	3,603,708	2,472,561	29,635,211	938,398	-	-	-	523,765	8,630,237	-	-	51,580	123,485	80,291	-	103,898	167,738	17,117	26,611	-	########	296,759	25,785
4	2027	10,763,718	19,268,214	-	2,179,664	20,256,257	6,768,531	528,715	3,712,019	2,546,738	27,777,148	967,410	-	-	-	539,878	8,889,190	-	-	51,580	123,485	80,291	-	103,898	167,738	17,117	26,611	-	########	305,622	147,127
5	2028	10,763,718	20,127,423	-	2,273,423	21,084,185	6,971,587	535,277	3,823,379	2,623,040	29,010,000	997,080	-	-	-	556,094	9,155,866	-	-	-	-	-	-	-	-	-	-	-	########	314,891	148,838
6	2029	10,763,718	20,127,423	-	2,273,423	21,084,185	7,329,352	968,898	4,013,961	2,755,500	23,897,002	997,080	-	-	-	264,808	9,090,530	-	-	-	-	-	-	-	-	-	-	-	########	314,891	148,838
7	2030	10,763,718	19,458,458	-	1,704,968	20,984,158	6,971,587	535,277	4,217,114	2,893,925	23,897,002	997,080	-	-	-	-	9,365,786	-	-	-	-	-	-	-	-	-	-	-	########	314,891	148,838
8	2031	10,763,718	20,146,327	-	2,273,423	23,571,087	7,618,491	582,735	4,253,758	2,898,486	23,241,719	-	-	-	-	-	9,645,840	-	-	-	-	-	-	-	-	-	-	-	########	235,232	189,938
9	2032	10,763,718	19,768,756	-	1,364,374	19,701,407	7,618,491	582,735	4,216,687	2,869,776	23,241,719	-	-	-	-	-	9,556,256	-	-	-	-	-	-	-	-	-	-	-	########	193,125	189,938
10	2033	10,763,718	20,539,982	-	36,490	23,560,081	7,715,196	-	5,714,034	2,433,975	25,783,987	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	########	233,202	188,932
11	2034	10,763,718	20,867,383	-	-	24,263,803	8,037,039	-	5,763,526	2,457,288	26,293,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	########	239,205	202,008
12	2035	10,763,718	19,214,712	-	-	12,763,101	8,038,131	-	5,810,131	2,510,141	27,022,663	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	########	121,192	194,147
13	2036	10,763,718	21,012,245	-	-	25,322,631	8,042,493	-	3,828,225	2,574,275	27,693,541	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	########	249,323	211,645
14	2037	10,763,718	19,447,171	-	-	15,360,905	8,065,121	-	2,111,106	2,610,104	28,236,412	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	########	152,152	114,470
15	2038	10,763,718	20,250,463	-	-	26,420,865	8,068,513	-	4,088,613	2,669,663	28,820,540	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	########	261,154	220,015
16	2039	10,763,718	20,250,463	-	-	26,420,865	8,068,513	-	4,088,613	2,669,663	29,413,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	########	261,154	220,015
17	2040	10,763,718	20,250,463	-	-	26,420,865	8,068,513	-	4,088,613	2,669,663	29,413,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	########	261,154	220,015
18	2041	10,763,718	20,250,463	-	-	26,420,865	8,068,513	-	4,088,613	2,669,663	29,413,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	########	261,154	220,015
19	2042	10,763,718	19,767,973	-	-	12,763,101	8,068,513	-	2,044,307	1,905,487	23,013,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	########	121,192	220,015
20	2043	10,763,718	20,250,463	-	-	26,420,865	8,068,513	-	4,088,613	2,669,663	29,413,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	########	261,154	220,015
21	2044	10,763,718	20,250,463	-	-	26,420,865	8,068,513	-	4,088,613	2,669,663	29,413,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	########	261,154	220,015
22	2045	10,763,718	32,663,529	-	-	30,003,967	8,115,604	-	4,609,351	3,013,685	32,903,721	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	########	-	249,623
23	2046	10,763,718	32,728,803	-	-	32,879,870	8,260,035	-	4,703,526	3,119,131	33,893,141	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	########	-	252,320
24	TOTAL	239,643,792	502,960,660	-	19,429,606	541,216,900	159,545,979	4,876,313	88,769,676	59,555,854	613,723,023	6,197,347	-	-	-	3,402,569	72,670,639	-	-	369,647	489,132	312,365	-	424,652	653,293	233,585	101,293	-	########	4,451,296	3,940,291

Line No.	Generator	REP 2029 PPA In-State Solar 100 MW	REP 2029 PPA In-State Solar 200 MW	REP 2029 PPA In-State Solar 250 MW	REP 2021 PPA In-State Solar 250 MW	REP 2022 PPA In-State Solar 250 MW	REP 2023 PPA In-State Solar 250 MW	REP 2024 PPA In-State Solar 100 MW	REP 2025 PPA In-State Solar 20 MW	REP 2026 PPA In-State Solar 250 MW	REP 2027 PPA In-State Solar 250 MW	REP 2028 PPA In-State Solar 187.5 MW	REP 2028 PPA In-State Solar 125 MW	REP 2028 PPA In-State Solar 62.5 MW	2029 VGP-REP PPA In-State Solar 612 MW	2030 VGP-REP PPA In-State Solar 18.5 MW	2031 VGP-REP PPA In-State Solar 39.5 MW	2032 VGP-REP PPA In-State Solar 47.5 MW	2033 VGP-REP PPA In-State Solar 60 MW	2034 VGP-REP PPA In-State Solar 67.5 MW	2035 VGP-REP PPA In-State Solar 33 MW	REPA and Program Total
	Year	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
24	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	107,147,484
25	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	110,993,621
26	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	114,330,843
27	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	117,823,855
28	2026	19,750,331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	142,867,748
29	2027	19,997,101	19,998,392	-	-	-	-	-	-	-	-	-	-	-	-	9,841,762	-	-	-	-	-	165,132,242
30	2028	19,997,101	19,998,392	16,226,143	-	-	-	-	-	-	-	-	-	-	-	7,877,862	7,086,650	-	-	-	-	251,882,322
31	2029	19,997,101	19,998,392	16,226,143	14,957,296	-	-	-	-	-	-	-	-	-	-	7,877,862	7,086,650	7,336,811	-	-	-	251,882,322
32	2030	19,997,101	19,998,392	16,226,143	14,957,296	14,600,427	-	-	-	-	-	-	-	-	-	7,877,862	7,086,650	7,336,811	7,100,991	-	-	251,882,322
33	2031	19,997,101	19,998,392	16,226,143	14,957,296	14,600,427	14,061,087	-	-	-	-	-	-	-	-	7,877,862	7,086,650	7,336,811	7,100,991	-	-	251,882,322
34	2032	19,997,101	19,998,392	16,226,143	14,957,296	14,600,427	14,061,087	14,061,087	-	-	-	-	-	-	-	7,877,862	7,086,650	7,336,811	7,100,991	6,871,769	-	251,882,322
35	2033	19,997,101	19,998,392	16,226,143	14,957,296	14,600,427	14,061,087	14,061,087	13,511,888	13,141,705	-	-	-	-	-	7,877,862	7,086,650	7,336,811	7,100,991	6,871,769	-	251,882,322
36	2034	19,997,101	19,998,392	16,226,143	14,957,296	14,600,427	14,061,087	14,061,087	13,511,888	13,141,705	13,111,888	-	-	-	-	7,877,862	7,086,650	7,336,811	7,100,991	6,871,769	6,871,777	251,882,322
37	2035	19,997,101	19,998,392	16,226,143	14,957,296	14,600,427	14,061,087	14,061,087	13,511,888	13,141,705	13,111,888	13,111,888	-	-	-	7,877,862	7,086,650	7,336,811	7,100,991	6,871,769	6,871,777	251,882,322
38	2036	19,997,101	19,998,392	16,226,143	14,957,296	14,600,427	14,061,087	14,061,087	13,511,888	13,141,705	13,111,888	13,111,888	13,111,888	-	-	7,877,862	7,086,650	7,336,811	7,100,991	6,871,769	6,871,777	251,882,322
39	2037	19,997,101	19,998,392	16,226,143	14,957,296	14,600,427	14,061,087	14,061,087	13,511,888	13,141,705	13,111,888	13,111,888	13,111,888	13,111,888	-	7,877,862	7,086,650	7,336,811	7,100,991	6,871,769	6,871,777	251,882,322
40	2038	19,997,101	19,998,392	16,226,143	14,957,296	14,600,427	14,061,087	14,061,087	13,511,888	13,141,705	13,111,888	13,111,888	13,111,888	13,111,888	13,111,888	7,877,862	7,086,650	7,336,811	7,100,991	6,871,769	6,871,777	251,882,322
41	2039	19,997,101	19,998,392	16,226,143	14,957,296	14,600,427	14,061,087	14,061,087	13,511,888	13,141,705	13,111,888	13,111,888	13,111,888	13,111,888	13,111,888	7,877,862	7,086,650	7,336,811	7,100,991	6,871,769	6,871,777	251,882,322
42	2040	19,997,101	19,998,392	16,226,143	14,957,296	14,600,427	14,061,087	14,061,087	13,511,888	13,141,705	13,111,888	13,111,888	13,111,888	13,111,888	13,111,888	7,877,862	7,086,650	7,336,811	7,100,991	6,871,769	6,871,777	251,882,322
43	2041	19,997,101	19,998,392	16,226,143	14,957,296	14,600,427	14,061,087	14,061,087	13,511,888	13,141,705	13,111,888	13,111,888	13,111,888	13,111,888	13,111,888	7,877,862	7,086,650	7,336,811	7,100,991	6,871,769	6,871,777	251,882,322
44	2042	19,997,101	19,998,392	16,226,143	14,957,296	14,600,427	14,061,087	14,061,087	13,511,888	13,141,705	13,111,888	13,111,888	13,111,888	13,111,888	13,111,888	7,877,862	7,086,650	7,336,811	7,100,991	6,871,769	6,871,777	251,882,322
45	2043	19,997,101	19,998,392	16,226,143	14,957,296	14,600,427	14,061,087	14,061,087	13,511,888	13,141,705	13,111,888	13,111,888	13,111,888	13,111,888	13,111,888	7,877,862	7,086,650	7,336,811	7,100,991	6,871,769	6,871,777	251,882,322
46	2044	19,997,101	19,998,392	16,226,143	14,957,296	14,600,427	14,061,087	14,061,087	13,511,888	13,141,705	13,111,888	13,111,888	13,111,888	13,111,888	13,111,888	7,877,862	7,086,650	7,336,811	7,100,991	6,871,769	6,871,777	251,882,322
47	2045	19,997,101	19,998,392	16,226,143	14,957,296	14,600,427	14,061,087	14,061,087	13,511,888	13,141,705	13,111,888	13,111,888	13,111,888	13,111,888	13,111,888	7,877,862	7,086,650	7,336,811	7,100,991	6,871,769	6,871,777	251,882,322
48	TOTAL	359,231,433	359,969,861	288,012,572	267,879,267	263,603,458	251,858,438	256,719,322	233,128,496	231,879,698	232,196,319	232,321,195	143,779,395	63,145,167	13,111,888	137,896,792	126,934,455	96,137,629	91,229,384	77,236,977	46,214,455	7,479,369,209

Line No.	Generator	Solar Gardens (Unsubscribed)	Solar Gardens 2020 Expansion (Unsubscribed)	Solar Gardens 2020 Expansion (Unsubscribed)	Hardy Hydro Upgrade	Lake Winds Energy Park	Cross Winds Energy Park	Cross Winds Energy Park (Phase II) (subscribed)	Cross Winds Energy Park (Phase II) (unsubscribed)	Gratiot County Wind Farm	Crescent Wind Farm	Heartland Wind Farm	Cloud Wind Solar	Sunfish (Unsubscribed)	Kerr (Unsubscribed)	VGP_REP_2027_116.82 MW (Unsubscribed)	VGP_REP_2027_226 MW (Unsubscribed)	Spring Creek	Muskegon	Muskegon Mills	Washtenaw	Lake Winds Energy Park Repowered	VGP_REP_2027_176.52 MW	VGP_REP_2027_2 25 MW	Kerr (Subscribed)	Sunfish (Subscribed)
	Year	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
47	2022	63,833	-	-	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	257,998	-	-	-	-	-	-	-	-	-	-	-	-	-
48	2023	63,833	-	-	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	257,998	-	-	-	-	-	-	-	-	-	-	-	-	-
49	2024	63,833	250,652	-	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	257,998	-	-	-	-	9,293,095	26,652,953	-	-	-	-	-	-	22,852,975
50	2025	63,833	777,964	-	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	257,998	-	-	-	-	15,752,105	56,996,893	10,780,747	10,780,747	-	-	-	-	56,970,535
51	2026	63,833	960,668	-	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	257,998	-	-	-	-	15,717,884	28,484,139	22,715,601	18,208,982	-	13,951,895	25,920,847	########	28,860,738
52	2027	63,833	82,273	-	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	257,998	-	-	-	-	15,585,773	28,212,139	22,518,613	18,115,418	-	13,814,126	25,720,776	########	28,620,780
53	2028	63,833	-	267,495	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	257,998	-	-	-	-	15,518,496	56,096,924	11,210,413	18,012,413	-	13,752,315	55,584,335	########	56,476,135
54	2029	63,833	-	360,488	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	257,998	-	-	-	-	15,427,485	27,889,629	22,336,895	17,902,455	-	13,714,850	25,482,276	########	28,237,650
55	2030	63,833	-	164,187	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	257,998	-	-	-	-	15,400,551	27,806,570	11,153,808	17,890,417	-	13,697,603	55,477,496	########	56,157,486
56	2031	63,833	-	152,496	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	257,998	-	-	-	-	15,278,107	27,660,899	22,278,176	17,728,642	-	13,576,852	25,352,716	########	28,022,151
57	2032	63,833	-	51,498	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	257,998	-	-	-	-	15,199,941	27,506,832	21,993,365	17,658,351	-	13,506,035	25,074,532	########	28,879,791
58	2033	63,833	-	-	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	257,998	-	-	-	-	15,130,733	27,353,103	11,833,733	17,588,408	-	13,436,218	24,796,348	########	28,736,325
59	2034	63,833	-	-	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	-	-	-	-	-	15,062,526	27,261,681	21,797,099	17,323,502	-	13,403,439	24,884,532	########	28,642,242
60	2035	63,833	-	-	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	-	-	-	-	-	14,991,475	27,072,045	11,814,115	17,184,475	-	13,367,276	24,692,716	########	28,476,345
61	2036	63,833	-	-	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	-	-	-	-	-	14,883,275	26,883,775	21,510,320	17,282,375	-	13,227,965	24,507,324	########	28,275,132
62	2037	63,833	-	-	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	-	-	-	-	-	14,775,075	26,695,505	11,206,505	17,380,275	-	13,088,654	24,321,932	########	28,073,919
63	2038	63,833	-	-	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	-	-	-	-	-	14,666,875	26,507,235	21,206,690	17,478,175	-	13,037,342	24,135,140	########	27,872,705
64	2039	63,833	-	-	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	-	-	-	-	-	14,558,475	26,319,035	11,000,875	17,576,075	-	12,986,030	23,948,348	########	27,671,491
65	2040	63,833	-	-	-	27,476,980	19,168,603	-	-	19,388,779	17,020,216	25,614,392	-	-	-	-	-	14,487,446	26,257,652	20,911,262	16,934,714	1,987,075	12,879,487	23,914,273	########	27,623,133
66	2041	63,833	-	-	-	26,981,292	19,168,603	-	-	19,388,779	17,020,216	25,614,392	-	-	-	-	-	14,417,753	26,149,622	20,864,113	16,799,350	19,122,251	12,844,842	23,847,179	########	27,627,137
67	2042	63,833	-	-	-	-	19,168,603	-	-	19,388,779	17,020,216	25,614,392	-	-	-	-	-	14,329,111	25,990,922	20,719,613	16,651,128	19,020,264	12,760,229	23,694,772	########	27,230,292
68	TOTAL	1,386,226	1,020,493	1,356,142	349,751,998	649,753,399	460,108,127	374,416,149	166,767,208	466,898,137	408,485,188	3,996,938	-	-	-	-	-	263,379,675	548,211,624	413,318,665	352,367,326	41,279,711	245,134,902	444,486,137	########	564,997,586

Line No.	Generator	REP 2026 Owned In-State Solar 200 MW	REP 2026 Owned In-State Solar 100 MW	REP 2029 Owned In-State Solar 250 MW	REP 2030 Owned In-State Solar 250 MW	REP 2031 Owned In-State Solar 250 MW	REP 2032 Owned In-State Solar 250 MW	REP 2033 Owned In-State Solar 250 MW	REP 2034 Owned In-State Solar 250 MW	REP 2035 Owned In-State Solar 250 MW	REP 2036 Owned In-State Solar 250 MW	REP 2037 Owned In-State Solar 250 MW	REP 2028 Owned In-State Solar 187.5 MW	REP 2028 Owned In-State Solar 125 MW	REP 2028 Owned In-State Solar 62.5 MW	REP 2029 Owned In-State Wind 100 MW	REP 2029 Owned In-State Wind 200 MW	REP 2028 Owned In-State Wind 250 MW	REP 2022 Owned In-State Wind 100 MW	REP 2023 Owned In-State Wind 600 MW	2029 VGP-REP CS In-State Solar 61.5 MW	2030 VGP-REP CS In-State Solar 96.5 MW	2031 VGP-REP CS In-State Solar 94.5 MW	2032 VGP-REP CS In-State Solar 92.5 MW	2033 VGP-REP CS In-State Solar 90 MW	2034 VGP-REP CS In-State Solar 87.5 MW	2035 VGP-REP CS In-State Solar 85 MW	Owned Total	GRAND TOTAL
	Year	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
70	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	109,170,515	215,412,395
71	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	109,150,181	216,600,487
72	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	147,088,918	261,787,811
73	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	156,738,790	312,508,483
74	2028	25,388,838	21,868,614	-	-	-	-	-	-	-	-	-	-	-	-	-	14,138,592	-	-	-	-	-	-	-	-	-	-	-	-	253,498,598	598,347,914
75	2029	42,611,157	25,355,379	36,498,997	-	-	-	-	-	-	-	-	-	-	-	-	14,500,000	29,867,882	-	-	-	4,968,421	-	-	-	-	-	-	-	238,515,434	537,833,923
76	2030	43,365,100	26,777,512	36,798,833	33,166,312	-	-	-	-	-	-	-	-	-	-	-	14,500,000	30,615,186	19,236,537	-	-	8,914,766	8,368,101	-	-	-	-	-	-	243,504,915	494,504,328
77	2031	43,365,100	26,777,512	36,798,833	33,166,312	37,979,753	-	-	-	-	-	-	-	-	-	-	14,500,000	30,615,186	19,236,537	19,236,537	8,914,766	8,368,101	8,039,933	-	-	-	-	-	-	249,000,000	498,000,000
78	2032	42,990,427	25,567,913	36,438,676	36,861,800	37,979,753	38,983,176	-	-	-	-	-	-	-	-	-	14,500,000	29,853,125	19,236,129	231,095,053	8,860,365	8,853,753	8,039,933	8,186,487	-	-	-	-	-	709,613,135	959,594,563
79	2033	41,784,637	25,892,921	35,753,108	36,710,465	37,862,917	38,699,155	39,701,988	-	-	-	-	-	-	-	-	14,500,000	29,785,387	29,455,886	230,154,258	-	8,795,366	8,980,268	8,067,672	8,128,422	-	-	-	-	725,721,903	1,058,986,755
80	2034	41,539,863	25,765,262	35,548,253	36,496,625	37,673,545	38,479,523	39,537,788	40,037,788	-	-	-	-	-	-	-	14,500,000	29,785,387	29,455,886	230,154,258	230,154,258	8,795,366	8,921,211	8,131,127	8,078,665	########	7,705,879	-	-	754,280,142	1,141,973,011
81	2035	41,156,588	25,483,196	35,183,788	36,111,168	37,273,192	38,084,218	39,108,210	39,596,210	41,070,610	-	-	-	-	-	-	14,500,000	29,491,641	29,219,476	227,932,815	227,932,815	8,698,368	8,868,953	8,194,583	8,028,285	########	7,627,712	########	352,867,906	1,164,801,106
82	2036	41,169,824	25,372,423	35,038,383	35,935,783	37,124,663	37,924,663	38,933,663	39,421,663	40,894,063	41,894,063	-	-	-	-	-	14,500,000	29,354,202	29,084,215	226,911,372	226,911,372	8,661,203	8,841,895	8,258,035	7,990,428	########	7,549,545	########	347,142,611	1,428,277,401
83	2037	40,972,442	25,268,273	35,892,236	36,054,627	36,971,292	37,862,992	38,983,083	40,012,676	41,093,738	42,191,545	43,317,595	-	-	-	-	14,098,237	28,806,302	28,427,231	220,331,081	220,331,081	8,423,325	8,625,083	8,257,627	7,972,328	########	7,654,080	########	2,136,942,038	1,564,667,493
84	2038	40,742,270	25,164,388	34,848,498	35,779,625	36,739,023	37,726,121	38,737,883	39,776,808	40,848,500	41,952,611	43,092,828	43,317,595	-	-	-	14,098,336	28,788,165	28,409,136	220,179,628	220,179,628	8,375,812	8,572,862	8,198,150	7,922,480	########	7,557,203	########	2,086,227,127	1,588,328,177
85	2039	40,488,860	25,248,280	33,699,033	35,392,457	36,500,009	37,532,345	38,583,026	39,573,731	40,634,052	41,721,757	42,837,390	32,986,336	23,577,600	-	14,098,000	28,788,187	28,409,886	220,154,258	220,154,258	8,326,323	8,528,633	8,114,108	7,855,790	########	7,518,005	########	2,086,280,887	1,608,167,826
86	2040	40,193,516	25,166,880	33,536,103	35,208,800	36,271,540	37,337,882	38,387,636	39,414,243	40,476,325	41,565,000	42,677,000	32,803,387	23,469,500	11,546,500	14,098,000	28,788,187	28,409,886	220,154,258	220,154,258	8,326,323	8,528,633	8,114,108	7,855,790	########	7,486,278	########	2,086,280,887	1,616,477,147
87	2041	40,207,170	25,113,383	33,426,362	35,057,364	36,102,857	37,088,727	38,293,935	39,321,086	40,378,772	41,459,586	42,570,996	32,782,972	22,639,671	11,505,867	14,098,000	28,788,187	28,409,886	220,154,258	220,154,258	8,326,323	8,528,633	8,114,108	7,855,790	########	7,471,003	########	2,086,280,887	1,634,298,970
88	2042	39,979,128	25,060,669	32,717,238	35,321,755	36,080,129	37,065,192	38,061,335	39,085,328	40,139,782	41,219,362	42,328,730	32,689,480	22,207,876	11,452,254	14,098,000	28,603,086	28,225,835	219,273,631	130,935,756	8,217,409	8,420,149	8,012,013	7,760,392	########	7,439,212	########	2,058,638,187	1,652,298,983
89	2043	39,903,093	25,954,012	32,157,221	35,061,986	36,024,952	37,001,398	37,988,875	39,012,316	40,072,105	41,159,079	42,253,986	32,540,389	22,274,638	11,439,338	14,050,132	28,750,132	28,422,776	220,208,343	130,869,696	8,202,676	8,203,373	7,968,023	7,776,215	########	7,414,228	########	2,059,973,149	1,629,216,425
90	2044	39,903,093	25,954,012	32,157,221	35,061,986	36,024,952	37,001,398	37,988,875	39,012,316	40,072,105	41,159,079	42,253,986	32,540,389	22,274,638	11,439,338	14,050,132	28,750,132	28,422,776	220,208,343	130,869,696	8,202,676	8,203,373	7,968,023	7,776,215	########	7,414,228	########	2,059,973,149	1,629,216,425
91	2045	39,903,093

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

CASE NO.: U-21962
EXHIBIT: A-8.5 (TSD-12)
PAGE: 1 of 1
witness: Jackson
DATE: November 2020

Renewable Energy Plan Projected FCM

Line No.	Generator	Apple Blossom	Beale Renewable Energy	Elk Rapids Hydro.	Fremont Community Digester	Harvest II Windfarm	Heritage Garden Windfarm I (Wind)	Heritage Garden Windfarm I (solar)	Heritage Sheldon Corners Windfarm I (MEC Phase 2)	Heritage Sheldon Corners Windfarm I (MEC Phase 3)	Michigan Wind 2	North American Natural Resources (Lansing)	Scenic View Dairy (Farmville)	Scenic View Dairy (Freeport)	WSWenewable Energy (Northern Oaks)	WSWenewable Energy (Pine Tree Acres)	Zeeland Farm Services (Plant 2)	SARP- 1-4	SARP-5	SARP-6	SARP-7	SARP-8	SARP-9	SARP-10	SARP-11	SARP- Anaerobic Digester	River Park Solar	Solar Gardens (Hudson-Iosco)	Solar Gardens 2020 Expansion (Unbundled)	Solar Gardens 2020 Expansion (Subscribed)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)	(AB)	(AC)
	Year	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
1	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	TOTAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Line No.	Generator	REP 2020 PPA In-State Solar 150 MW	REP 2020 PPA In-State Solar 200 MW	REP 2021 PPA In-State Solar 200 MW	REP 2021 PPA In-State Solar 250 MW	REP 2022 PPA In-State Solar 200 MW	REP 2022 PPA In-State Solar 250 MW	REP 2023 PPA In-State Solar 200 MW	REP 2023 PPA In-State Solar 250 MW	REP 2025 PPA In-State Solar 200 MW	REP 2025 PPA In-State Solar 250 MW	REP 2026 PPA In-State Solar 200 MW	REP 2027 PPA In-State Solar 200 MW	REP 2028 PPA In-State Solar 107.5 MW	REP 2029 PPA In-State Solar 125 MW	REP 2030 PPA In-State Solar 62.5 MW	2020 VIP REP PPA In-State Solar 41.5 MW	2020 VIP REP PPA In-State Solar 50.5 MW	2021 VIP REP PPA In-State Solar 50.5 MW	2022 VIP REP PPA In-State Solar 25.5 MW	2022 VIP REP PPA In-State Solar 50 MW	2022 VIP REP PPA In-State Solar 25 MW	2023 VIP REP PPA In-State Solar 37.5 MW	2020 VIP REP PPA In-State Solar 32 MW	REPA and Program Total
		(AD)	(AE)	(AF)	(AG)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)	(AR)	(AS)	(AT)	(AU)	(AV)	(AW)	(AX)	(AY)	(AZ)	(BA)	
	Year	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
24	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	2028	1,726,278	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,726,278
29	2029	1,705,230	2,917,901	-	-	-	-	-	-	-	-	-	-	-	-	-	698,625	-	-	-	-	-	-	-	-	4,821,132
30	2030	1,694,990	2,900,441	2,977,930	-	-	-	-	-	-	-	-	-	-	-	-	694,556	661,093	-	-	-	-	-	-	-	7,973,375
31	2031	1,686,036	2,883,498	2,960,125	3,039,539	-	-	-	-	-	-	-	-	-	-	-	690,556	657,236	659,301	-	-	-	-	-	-	10,968,347
32	2032	1,694,600	2,862,826	2,939,909	3,018,982	3,129,989	-	-	-	-	-	-	-	-	-	-	686,546	653,320	655,386	617,776	-	-	-	-	-	13,888,336
33	2033	1,675,316	2,843,687	2,920,245	3,018,764	3,097,208	-	3,180,051	-	-	-	-	-	-	-	-	675,197	643,279	653,531	610,772	597,843	-	-	-	-	18,766,196
34	2034	1,667,238	2,824,546	2,900,581	2,979,349	3,096,154	-	3,135,173	3,238,213	-	-	-	-	-	-	-	671,187	633,239	651,677	608,268	596,200	577,929	-	-	-	23,224,766
35	2035	1,658,238	2,805,546	2,879,279	2,958,049	3,074,095	-	3,145,961	3,220,055	3,104,209	-	-	-	-	-	-	667,988	623,124	649,473	606,477	594,421	574,643	397,545	-	-	25,335,828
36	2036	1,648,638	2,836,545	2,871,418	3,051,205	-	-	3,135,765	3,234,273	3,202,401	3,390,139	-	-	-	-	-	663,393	613,424	633,969	604,109	592,665	572,532	396,288	-	-	26,423,136
37	2037	1,639,652	2,806,715	2,861,696	2,959,964	3,056,439	-	3,139,641	3,203,551	3,289,511	3,376,676	3,487,951	-	-	-	-	662,541	609,736	631,403	603,608	590,535	570,196	394,640	-	-	26,761,594
38	2038	1,629,332	2,788,139	2,853,395	2,949,573	3,038,809	-	3,105,209	3,183,539	3,268,722	3,356,133	3,466,453	3,583,351	-	-	-	658,098	605,730	627,909	597,899	582,893	566,669	390,139	-	-	25,390,242
39	2039	1,620,750	2,773,997	2,838,798	2,935,347	3,023,869	-	3,084,828	3,167,263	3,252,258	3,338,272	3,448,988	2,563,321	1,807,055	-	-	654,660	602,423	624,323	594,798	579,869	563,799	386,398	-	-	23,891,932
40	2040	1,614,276	2,763,736	2,827,224	2,923,625	3,012,264	-	3,073,426	3,154,633	3,239,503	3,326,333	3,436,376	2,555,005	1,803,305	-	920,138	650,256	599,061	621,861	591,238	577,058	561,175	384,736	-	-	24,882,266
41	2041	1,609,837	2,755,536	2,820,909	2,916,373	2,964,373	-	3,064,765	3,147,137	3,231,628	3,318,151	3,427,214	2,623,612	1,799,663	-	916,336	633,235	623,357	586,925	576,276	560,193	387,756	-	-	-	24,986,757
42	2042	1,606,197	2,749,836	2,814,778	2,910,178	2,957,978	-	3,058,178	3,140,577	3,224,903	3,311,403	3,420,453	2,617,903	1,796,103	-	914,536	629,235	621,557	585,125	574,476	558,493	386,156	-	-	-	24,917,093
43	2043	1,597,097	2,735,676	2,807,176	2,903,628	2,951,428	-	3,044,328	3,123,217	3,207,387	3,293,403	3,403,864	2,604,407	1,792,607	932,396	909,336	623,327	609,964	580,275	573,786	556,923	384,699	-	-	-	24,853,345
44	2044	1,588,730	2,721,372	2,793,259	2,873,654	2,944,318	-	3,027,798	3,109,424	3,193,561	3,279,069	3,387,387	2,593,371	1,775,399	931,598	902,536	620,003	602,808	580,747	568,324	553,477	383,176	-	-	-	24,581,408
45	2045	1,578,486	2,703,450	2,773,437	2,843,713	2,913,618	-	3,003,797	3,084,828	3,167,963	3,253,903	3,362,863	2,572,872	1,753,368	920,198	896,023	613,575	596,023	576,198	566,706	549,099	380,139	-	-	-	24,302,618
46	TOTAL	20,600,130	47,739,984	46,986,938	44,185,429	43,361,358	-	46,185,684	37,864,698	36,888,493	35,232,488	30,640,903	20,988,308	12,028,023	2,683,432	11,361,938	10,213,513	9,278,808	8,388,728	7,016,357	6,763,028	4,250,458	-	-	-	426,422,988

Line No.	Generator	Solar Gardens (Unsubscribed)	Solar Gardens 2020 Expansion (Unsubscribed)	Solar Gardens 2020 Expansion (Unsubscribed)	Hardy Hydro Upgrade	Lake Winds Energy Park	Cross Winds Energy Park	Cross Winds Energy Park (Phase III Unsubscribed)	Cross Winds Energy Park (Phase III Subscribed)	Gratiot County Wind Farm	Cresent Wind Farm	Heartland Wind Farm	Circuit Wind Solar	Sunfish (Unsubscribed)	Kerr (Unsubscribed)	VIP_REP_2027_116.62 MW (Unsubscribed)	VIP_REP_2027_220 MW (Unsubscribed)	Spring Creek	Muskegon	Muskegon	Wolverine Mills	Wolverine	Lake Winds Energy Park Repowered	VIP_REP_2027_119.82 MW	VIP_REP_2027_220 MW	Kerr (Subscribed)	Sunfish (Subscribed)
		(AI)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)	(AR)	(AS)	(AT)	(AU)	(AV)	(AW)	(AX)	(AY)	(AZ)	(BA)	(BB)	(BC)	(BD)	(BE)	(BF)	(BG)	(BH)
	Year	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
47	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57	2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60	2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
62	2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
63	2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
67	2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
69	TOTAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Line No.	Generator	REP 2020 Owned In-State Solar 200 MW	REP 2020 Owned In-State Solar 150 MW	REP 2020 Owned In-State Solar 200 MW	REP 2020 Owned In-State Solar 250 MW	REP 2021 Owned In-State Solar 250 MW	REP 2022 Owned In-State Solar 250 MW	REP 2023 Owned In-State Solar 250 MW	REP 2024 Owned In-State Solar 250 MW	REP 2025 Owned In-State Solar 250 MW	REP 2026 Owned In-State Solar 250 MW	REP 2027 Owned In-State Solar 250 MW	REP 2028 Owned In-State Solar 187.5 MW	REP 2029 Owned In-State Solar 125 MW	REP 2030 Owned In-State Solar 62.5 MW	REP 2020 Owned In-State Solar 100 MW	REP 2020 Owned In-State Wind 250 MW	REP 2020 Owned In-State Wind 200 MW	REP 2022 Owned In-State Wind 250 MW	REP 2020 Owned In-State Wind 300 MW	2020 VIP REP CS In-State Solar 41.5 MW	2020 VIP REP CS In-State Solar 50.5 MW	2021 VIP REP CS In-State Solar 50.5 MW	2022 VIP REP CS In-State Solar 50 MW	VIP REP 2027 CS In-State Solar 50	2036 VIP REP CS In-State Solar 67.5MW	VIP REP 2027 CS In-State Solar 25	Demand Total	GRAND TOTAL
		(BI)	(BJ)	(BK)	(BL)	(BM)	(BN)	(BO)	(BP)	(BQ)	(BR)	(BS)	(BT)	(BU)	(BV)	(BW)	(BX)	(BY)	(BZ)	(CA)	(CB)	(CC)	(CD)	(CE)	(CF)	(CG)	(CH)	(CI)	(CJ)
	Year	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
70	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
71	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
73	2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
74	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,726,278
76	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,821,132
77	2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7,973,375
78	2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10,968,347
79	2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13,888,336
80	2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18,766,196
81	2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19,914,815
82	2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23,135,828
83	2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26,423,136
84	2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26,761,594
85	2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25,390,242
86	2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23,891,932
87	2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24,882,266
88	2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24,986,757
89	2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24,917,093
90	2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24,853,345
91	2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24,581,408
92	2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23,553,618
93	TOTAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	426,422,988

SARP - Experimental/Advanced Renewable Program

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

CASE NO.: U-21816
EXHIBIT: A-30 (ZSC-7)
PAGE: 1 of 1
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	(a)	(b)	(c)
Line No.	**Year**	**LWEP Transfer Price Schedule**	**REPAs Formerly Assigned to 15805/16581 Transfer Price Schedule**
		$/MWh	**$/MWh**
1	2025	$ 119.60	$ 109.01
2	2026	$ 124.11	$ 113.17
3	2027	$ 129.32	$ 117.55
4	2028	$ 136.76	$ 124.88
5	2029	$ 142.32	$ 129.92
6	2030	$ 145.34	$ 132.63
7	2031	$ 148.45	$ 135.43
8	2032	$ 151.66	$ 136.24
9	2033	$ 154.93	$ 137.55
10	2034	$ 158.26	$ 139.42
11	2035	$ 161.68	$ 142.42
12	2036	$ 165.16	$ 145.49
13	2037	$ 168.72	$ 148.63
14	2038	$ 172.36	$ 151.83
15	2039	$ 176.07	$ 155.11
16	2040	$ 179.87	$ 158.45
17	2041	$ 183.75	$ 161.86
18	2042	$ 187.71	$ 165.35
19	2043	$ 188.21	$ 168.92
20	2044	$ 178.46	$ 172.56
21	2045	$ 182.26	$ 176.27

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

CASE NO.: U-21816
EXHIBIT: A-31 (ZSC-8)
PAGE: 1 of 1
WITNESS: ZSCole
DATE: November 2024

Formula				(c) - (b)			(f) - (e)	(d) + (g)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Year	LWEP & LWEP Repowered Transfer Cost - Existing TP Schedule	LWEP & LWEP Repowered Transfer Cost - Newly Proposed Schedule	Change in Cost Transferred to PSCR from LWEP & LWEP Repowered	REPAs Formerly Assigned to 15805/16581 Transfer Cost - Existing TP Schedule	REPAs Formerly Assigned to 15805/16581 Transfer Cost - Newly Proposed Schedule	Change in Cost Transferred to PSCR from REPAs under 15805/16581 TP Schedule	Net Total Change in Cost Transferred to PSCR
		$	$	$	$	$	$	$
1	2025	$ 29,875,207	$ 29,874,982	$ (226)	$ 87,617,622	$ 87,618,927	$ 1,305	**$ 1,080**
2	2026	$ 31,001,655	$ 31,001,538	$ (117)	$ 90,907,743	$ 90,907,089	$ (653)	**$ (770)**
3	2027	$ 32,303,989	$ 32,302,948	$ (1,041)	$ 94,346,280	$ 94,347,187	$ 907	**$ (134)**
4	2028	$ 34,160,451	$ 34,161,392	$ 941	$ 100,052,092	$ 100,053,111	$ 1,019	**$ 1,959**
5	2029	$ 35,550,009	$ 35,550,229	$ 220	$ 103,899,003	$ 103,898,103	$ (900)	**$ (680)**
6	2030	$ 36,303,495	$ 36,304,597	$ 1,103	$ 105,999,324	$ 105,997,363	$ (1,961)	**$ (858)**
7	2031	$ 37,081,314	$ 37,081,447	$ 133	$ 106,973,958	$ 106,972,714	$ (1,244)	**$ (1,111)**
8	2032	$ 37,882,650	$ 37,883,275	$ 625	$ 100,864,497	$ 100,866,947	$ 2,450	**$ 3,076**
9	2033	$ 38,699,618	$ 38,700,091	$ 473	$ 97,927,552	$ 97,927,394	$ (159)	**$ 315**
10	2034	$ 39,532,914	$ 39,531,894	$ (1,019)	$ 99,219,194	$ 99,221,736	$ 2,542	**$ 1,523**
11	2035	$ 40,385,375	$ 40,386,179	$ 804	$ 101,358,625	$ 101,356,761	$ (1,864)	**$ (1,060)**
12	2036	$ 41,255,971	$ 41,255,451	$ (520)	$ 103,543,512	$ 103,541,604	$ (1,909)	**$ (2,428)**
13	2037	$ 42,145,322	$ 42,144,706	$ (616)	$ 105,775,583	$ 105,776,264	$ 681	**$ 65**
14	2038	$ 43,053,867	$ 43,053,945	$ 78	$ 108,055,638	$ 108,053,624	$ (2,015)	**$ (1,936)**
15	2039	$ 43,981,790	$ 43,980,669	$ (1,121)	$ 110,384,520	$ 110,387,918	$ 3,398	**$ 2,277**
16	2040	$ 44,929,856	$ 44,929,874	$ 18	$ 112,763,999	$ 112,764,913	$ 914	**$ 931**
17	2041	$ 45,898,471	$ 45,899,062	$ 591	$ 115,194,930	$ 115,191,725	$ (3,205)	**$ (2,614)**
18	2042	$ 46,887,572	$ 46,888,234	$ 662	$ 117,677,306	$ 117,675,471	$ (1,836)	**$ (1,174)**
19	2043	$ 50,052,037	$ 50,052,459	$ 422	$ 120,213,750	$ 120,216,150	$ 2,401	**$ 2,823**
20	2044	$ 44,698,805	$ 44,699,800	$ 995	$ 122,804,374	$ 122,806,648	$ 2,274	**$ 3,269**
21	2045	$ 45,528,024	$ 45,526,874	$ (1,150)	$ 125,450,383	$ 125,446,962	$ (3,421)	**$ (4,571)**
22	**TOTAL**	**$ 841,208,390**	**$ 841,209,646**	**$ 1,255**	**$ 2,231,029,886**	**$ 2,231,028,611**	**$ (1,276)**	**$ (20)**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

CASE NO.: U-21816
EXHIBIT: A-32 (ZSC-9)
PAGE: 1 of 1
WITNESS: ZSCole
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Forecasted VGP Program Subscribed Consumption (MWh) By Year			(b) + (c) + (d)			(h-1) + (i)	(f) + (g)		
1	**Year**	**Renewable Energy Program-Residential & Green Giving Subscribed Load (MWh)**	**Renewable Energy Program Commercial & Industrial Subscribed Load (MWh)**	**Solar Gardens Subscribed Load (MWh)**	**Cumulative Total VGP Subscribed Load (MWh)**	**Incremental Solar Supply (MW)[1]**	**Incremental Wind Supply (MW)[1]**	**Cumulative Total Supply (MW)**	**New Supply (MW)**	**Incremental Resource Notes[1]**	**Customer Demand Notes:**
2	2024	0	386,688	6,150	392,838	4.5	120	125	0	REP: Cross Winds II & III Solar Gardens: WMU, GVSU, Cadillac	REP C&I - Firm forecast: Based on executed contracts and supply online (CWEP II & III) Solar Gardens - 4.5 MW of existing capacity @ 15.6% NCF
3	2025	3,856	382,832	6,150	392,838	0	0	125	0		REP C&I - Firm forecast: Based on executed contracts and supply online (CWEP II & III) Solar Gardens - 4.5 MW of existing capacity @ 15.6% NCF
4	2026	13,770	912,684	7,464	933,918	312	0	436	312	REP: Sunfish 2 Solar Gardens: 2.5 MW 2026 SG Project	REP C&I - Firm forecast: Based on executed contracts and planned available supply online (CWEP II, III, Sunfish II) Solar Gardens - Add'l 2.5 MW for 2026 SG Project @ 24% NCF
5	2027	25,624	1,053,328	8,778	1,087,730	85	0	521	85	REP: Karn	REP C&I - Firm forecast: Based on executed contracts and planned available supply online (CWEP II, III, Sunfish II, Karn)
6	2028	39,516	1,670,089	10,092	1,719,697	337	0	858	337	REP: VGP_REP_2027_116.92 MW, VGP_REP_2027_220 MW	REP C&I - Based on assumption we will fully subscribe all planned assets. (CWEP II, III, Sunfish II, Karn, VGP_REP_2027_116.92 MW, VGP_REP_2027_220 MW)
7	2029	59,821	1,886,567	11,406	1,957,794	123	0	981	123	REP: 123 MW TBD	REP C&I - 236,783 MWh of new contracts (123 MW) added in 2029 (includes Resi/GG), with a ~5% decline in sales each year thereafter as it will become increasingly more difficult to sell due to market penetration and competing solutions.
8	2030	62,812	2,108,520	11,143	2,182,475	120	0	1,101	120	REP: 117 MW TBD Solar Gardens: 3 MW TBD	50% RPS Compliance Solar Gardens - Add'l 3 MW for TBD project @ 20% NCF
9	2031	65,953	2,319,076	12,194	2,397,223	111	0	1,211	111	REP: 111 MW TBD	
10	2032	69,250	2,518,790	13,246	2,601,286	105	0	1,317	105	REP: 105 MW TBD	
11	2033	72,713	2,708,189	14,297	2,795,198	100	0	1,417	100	REP: 100 MW TBD	
12	2034	76,348	2,887,771	15,348	2,979,468	95	0	1,512	95	REP: 95 MW TBD	REP Resi & Green Giving - Subscription volume to remain flat in 2035 and thereafter based on achieving 0.7% saturation = ~40 MW of solar capacity.
13	2035	80,166	3,011,939	15,348	3,107,453	66	0	1,578	66	REP: 66 MW TBD	60% RPS Compliance
14	2036	80,166	3,011,939	15,348	3,107,453	0	0	1,578	0		**REP C&I - Subscription volume to remain flat in 2035 and thereafter based on achieving 15% saturation**
15	2037	80,166	3,011,939	15,348	3,107,453	0	0	1,578	0		
16	2038	80,166	3,011,939	15,348	3,107,453	0	0	1,578	0		
17	2039	80,166	3,011,939	15,348	3,107,453	0	0	1,578	0		
18	2040	80,166	3,011,939	15,348	3,107,453	0	0	1,578	0		
19	2041	80,166	3,011,939	15,348	3,107,453	0	0	1,578	0		
20	2042	80,166	3,011,939	15,348	3,107,453	0	0	1,578	0		
21	2043	80,166	3,011,939	15,348	3,107,453	0	0	1,578	0		
22	2044	80,166	3,011,939	15,348	3,107,453	0	0	1,578	0		
23	2045	80,166	3,011,939	15,348	3,107,453	0	0	1,578	0		

Footnotes
1. 2024 represents existing supply

Appendix G: September 11, 2025 Order in Case No. U-21816 –
Consumers Energy Amended REP Approval

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of **CONSUMERS ENERGY COMPANY's** application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023.	)	Case No. U-21816

At the September 11, 2025 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Katherine L. Peretick, Commissioner
Hon. Shaquila Myers, Commissioner

ORDER

History of Proceedings

On November 15, 2024, Consumers Energy Company (Consumers) filed an application in this case, with supporting testimony and exhibits, pursuant to Public Act 295 of 2008 (Act 295), as amended by Public Act 235 of 2023 (Act 235), MCL 460.1022(3) requesting approval of an amendment to the company's renewable energy plan (REP).

A prehearing conference was held on January 8, 2025, before Administrative Law Judge Jonathan F. Thoits (ALJ) at which the ALJ recognized the intervention of the Michigan Department of Attorney General (Attorney General), and granted petitions to intervene filed by the Association of Businesses Advocating Tariff Equity (ABATE); Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, and Vote Solar

(collectively, the Clean Energy Organizations or CEOs); Great Lakes Renewable Energy Association, Inc. (GLREA); Hemlock Semiconductor Operations LLC; Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United (collectively, MEIU); Michigan Environmental Council (MEC); and Cadillac Renewable Energy L.L.C., Genesee Power Station Limited Partnership, Grayling Generating Station Limited Partnership, T.E.S. Filer City Station Limited Partnership, and National Energy of McBain, LLC (collectively, Biomass Merchant Plants or BMPs). Consumers and the Commission Staff (Staff) also participated in the proceeding. A schedule for the case was established by the ALJ.

On January 16, 2025, the Natural Resources Defense Council (NRDC) filed a petition to intervene out of time. No objection was entered and on January 30, 2025, the ALJ granted NRDC's petition.

On January 21, 2025, the ALJ adopted a protective order for use in this matter.

On February 28, 2025, the Attorney General filed a motion to compel discovery responses from Consumers, and the company filed a response to the motion on March 5, 2025.

On March 12-13, 2025, direct testimony and exhibits were filed by the Staff, the Attorney General, ABATE, the BMPs, the CEOs, GLREA, MEC/NRDC, and MEIU, some of which were filed confidentially. On April 8, 2025, Consumers, the Staff, ABATE, the BMPs, the CEOs, and GLREA filed rebuttal testimony and exhibits. On April 9 and 17, 2025, the BMPs filed corrected direct testimony and exhibits. On April 11, 2025, ABATE filed revised exhibits. Consumers filed revised testimony and exhibits on April 18, 2025.

Evidentiary hearings were held on April 21 and 24, 2025, wherein testimony and exhibits were bound into the record and cross-examination took place.

Consumers, the Staff, the Attorney General, ABATE, the BMPs, the CEOs, GLREA, MEC/NRDC, and MEIU filed initial briefs on May 21, 2025. On June 10, 2025, Consumers, the Attorney General, ABATE, the BMPs, the CEOs, GLREA, MEC/NRDC, and MEIU filed reply briefs. The Staff filed a letter stating that it would not be filing a reply brief.

The ALJ issued a Proposal for Decision (PFD) on August 1, 2025. On August 11, 2025, Consumers, the Staff, the Attorney General, the BMPs, the CEOs, GLREA, MEC/NRDC, and MEIU filed exceptions to the PFD. On August 18, 2025, Consumers, the Attorney General, ABATE, GLREA, MEC/NRDC, and MEIU filed replies to exceptions. The BMPs filed a letter stating that they would not be filing replies to exceptions.

The record consists of testimony from 10 witnesses contained within 884 pages of public and confidential transcript, along with 105 exhibits (inclusive of schedules). The docket also contains a public comment, which can be viewed in the section of the docket labeled "Case Comments." *See*, Case No. U-21816, filing #U-21816-0001-CC (as of September 10, 2025).

Statutory Requirements

Pursuant to Act 295, electric providers must maintain REPs that meet certain renewable energy credit (REC) portfolio standards (RPSs). Section 28 of Act 295, as amended by Act 235, MCL 460.1028, requires electric providers to achieve an RPS of 15% through 2029, 50% in 2030 through 2034, and 60% in 2035 and each year thereafter. Electric providers must meet the RPS with RECs obtained by any of the following means:

> (a) Generating electricity from renewable energy systems for sale to retail customers.
> (b) Purchasing or otherwise acquiring renewable energy and capacity.
> (c) Purchasing or otherwise acquiring renewable energy credits without the associated renewable energy or capacity. Renewable energy credits acquired under this subdivision shall be produced within the territory of the regional transmission organization of which the electric provider is a member, and, except for a municipally owned electric utility, shall not exceed 5% of an electric provider's

> renewable energy credits annually used to comply with the renewable energy standard. Renewable energy credits acquired under this subdivision are not subject to the requirements of section 29 and shall not be used to comply with the renewable energy standard after 2035.

MCL 460.1028(5).

In addition, MCL 460.1022(3) states, in relevant part, that:

> [w]ithin 1 year after the effective date of the amendatory act that added section 51, and within 2 years after the commission issues an order approving the electric provider's last amended renewable energy plan, an electric provider shall file an amended renewable energy plan that includes a forecast of the renewable energy resources needed to comply with the renewable energy credit standard pursuant to a filing schedule established by the commission. For an electric provider whose rates are regulated by the commission, the commission shall conduct a contested case hearing on the amended renewable energy plan pursuant to the administrative procedures act of 1969, 1969 PA 306, MCL 24.201 to 24.328. After the hearing, the commission shall approve, with any changes consented to by the electric provider, or reject the amended renewable energy plan. For all other electric providers, the commission shall provide an opportunity for public comment on the amended renewable energy plan. After the applicable opportunity for public comment, the commission shall determine whether any amendment to the renewable energy plan proposed by the provider complies with this act. For alternative electric suppliers, the commission shall approve, with any changes consented to by the electric provider, or reject any proposed amendments to the renewable energy plan. For each amended renewable energy plan filed by an electric provider, the commission shall issue a final order within 300 days after the date the amended renewable energy plan was filed with the commission.

Further, MCL 460.1022 states that:

> (5) For an electric provider whose rates are regulated by the commission, the commission shall approve amendments to the renewable energy plan if the commission determines both of the following:
>
> (a) That the amended renewable energy plan is reasonable and prudent. In making this determination, the commission shall take into consideration projected costs and whether or not projected costs in prior amended renewable energy plans were exceeded.
>
> (b) That the amended renewable energy plan is consistent with the purpose set forth in section 1(2) and meets the renewable energy credit standard.
>
> (6) For an electric provider whose rates are regulated by the commission, the commission shall review the projected costs of the renewable energy plan and

> approve, in whole or in part, the projected costs if the commission finds those projected costs, in whole or in part, to be reasonable and prudent. In making this determination, the commission shall consider whether projected costs in prior renewable energy plans were exceeded.

Following the enactment of Act 295, Consumers filed its REP on February 17, 2009, in Case No. U-15805, which was approved by the Commission on May 26, 2009. The company's REP has subsequently been amended and it contains several amendments that were approved by the Commission, most recently in Case No. U-21374.

On February 8, 2024, the Commission issued an order in Case No. U-21568 requiring Consumers to file its amended REP no later than November 15, 2024. In that same case, the Commission also approved Filing Requirements and Instructions for Renewable Energy Plans for Michigan Investor-Owned Retail Rate-Regulated Electric Utilities. Accordingly, Consumers filed its amended REP in this docket on November 15, 2024.

Consumers Energy Company's Proposed Amended Renewable Energy Plan

As an initial matter, the Commission notes that although several intervenors objected to Consumers' proposed amended REP, the intervenors' objections were limited to specific portions—not the entirety—of the company's amended REP. Therefore, the Commission finds that the undisputed portions of Consumers' REP are approved and shall not be addressed in detail in this order.

1. Renewable Energy Credit Portfolio Standard

    a. Distributed Generation Renewable Energy Credits

Consumers noted that its REC portfolio must be calculated using:

> [t]he average number of megawatt hours [(MWh)] of electricity sold by the electric provider annually during the previous 3 years to retail customers in this state, less the amount of sales attributable to customers participating in an electric provider's voluntary green pricing [(VGP)] program under section 61 and the outflow from

> customers participating in the distributed generation [(DG)] program under section 173 for that year.

2 Tr 50-51 (quoting MCL 460.1028(b)(ii)). To calculate the number of MWh of electricity sold by the company, less the MWh of sales attributable to customers participating in Consumers' DG program, the company provided a projection for DG in Exhibit A-3. The company stated that "[t]he projection reflects outflow from both the Company's legacy net metering program and the Company's DG program, as defined in Section C11.3 of the Company's electric rate book. The DG outflow forecast specifically relies on the actual data for the two program types from 2022 and 2023." 2 Tr 51. Consumers contended that the projections do not include any generation consumed by the customers for their own use; rather, the forecast only includes excess generation that is sent to the grid. *See*, Consumers' initial brief, p. 8.

GLREA noted that Consumers' proposed amended REP includes an increasing amount of REC purchases. GLREA asserted that the Commission should require Consumers to purchase RECs from projects that fall under the DG program and the Public Utility Regulatory Policies Act of 1978 (PURPA) before they purchase out-of-state RECs, so long as the cost of the RECs from the DG and PURPA projects is less than or equal to out-of-state RECs. *See*, 4 Tr 621; GLREA's initial brief, pp. 17-18. In addition, GLREA stated that DG RECs could "be used to meet non-contracted VGP customer demand." 4 Tr 589.

The Staff noted that in Case No. U-21375, it analyzed the effect of using DG RECs for VGP or RPS compliance. The Staff explained that it:

> developed a simplified model using the RPS requirements, as well as the obligation to serve load, to isolate what effect using DG RECs for either VGP or RPS compliance would have on the total number of renewables required to meet the RPS requirement. In this simplified model, the only independent variable was the amount of DG on the system and it was assumed for simplicity that all DG RECs were used if they were available. There were five different cases considered by Staff; Case A is a case were no DG RECs are used for either compliance with RPS

> or VGP, Case B is were DG outflow RECs are used for satisfying VGP load, Case C is where DG outflow RECs are used for satisfying RPS Compliance, Case D is where DG RECs from both outflow and RECs from DG generation that is consumed onsite are used for RPS compliance, and Case E is a case in which there was assumed to be no VGP load and no DG RECs were used either for RPS Compliance or VGP load.

4 Tr 854-855 (footnotes omitted). The Staff stated that "[t]he simplified model showed mathematically that, all else being equal, the use of DG RECs either for VGP or RPS compliance reduces the total number of renewables on the system required to meet the RPS and VGP requirement." 4 Tr 855 (footnote omitted).

The Staff also asserted that if the energy produced from DG is consumed onsite and is offsetting the load Consumers would otherwise need to serve, the generation cannot also count as RECs that can be sold to another entity. The Staff explained that "RECs are a commodity that represents the 'renewable attribute' of generation which we have separated from the energy that is actually produced. This arrangement makes sense because you cannot have electron traceability on the wider bulk electric system." Staff's initial brief, pp. 18-19 (citing 5 Tr 855). Thus, the Staff argued that if the DG RECs that are consumed onsite are sold to another entity, the generation would no longer be considered "renewable" because the renewable attribute of the generation has been sold and the generation would no longer be eligible for the DG program. More specifically, the Staff asserted that:

> [Act] 235 requires that in order to be eligible for the DG program, customers must utilize an eligible electric generator. [Act] 235 at MCL 460.1005(e) defines an eligible electric generator as a methane digestor or a renewable energy system. Staff witness Zachary C. Heidemann testified that if the customer has sold their RECs then they no longer own the RECs associated with generation that is consumed onsite and therefore it is no longer an eligible electric generator.

Staff's initial brief, p. 19 (citing 4 Tr 856). The Staff stated that because no other renewable resource that uses onsite generation is considered renewable after the RECs it generates are sold,

DG should be treated the same. In the event the Commission finds that the purchase of DG RECs is not double-counting, the Staff requested that the Commission find that "DG RECs should only be sold to the Company at the Company's discretion, with a reasonable rationale for doing so." Staff's initial brief, p. 21.

Furthermore, the Staff noted that, pursuant to Act 235, a DG customer "shall own any renewable energy credits granted for electricity generated on the customer's site under the distributed generation program . . . ." Staff's initial brief, p. 22 (quoting MCL 460.1179). However, the Staff stated that the sale of the REC:

> would result in the usage otherwise covered by that generation to ostensibly require RECs to be retired in proportion with the clean or renewable requirement associated with that same usage. [Act 235] includes neither DG customer usage behind the meter covered by the DG generation *or* the outflow associated the DG generation in the amount of usage necessary to cover with clean and renewable generation.

Staff's initial brief, p. 23 (emphasis in original). The Staff also contended that although DG resources are renewable by definition, it appears that the Legislature, in enacting Act 235, intended that Sections 73 and 79 would harmonize by recognizing that DG is already clean and renewable and should not be included in the usage that the company must cover with clean or renewable energy. According to the Staff:

> [i]f a DG customer does not seek to have RECs granted for its generation, the RECs that would otherwise exist are effectively retired to cover the generation. If a DG customer does seek to have RECs granted, the ownership stays with the customer so they can be retired in order to maintain the renewable status of the generation. Therefore, the appropriateness of participation in the DG program includes the exclusion of usage associated with that generation from the clean and renewable standard. To allow an entity other than the customer to own any RECs associated with DG generation would undermine both the program itself and the clean and renewable standards; therefore, the Legislature prevented this from occurring. Notably, the law is silent on the disposition of any such RECs. However, only by assuming their retirement by the owner can the various portions of the law be read so as not to produce an unreasonable result and should therefore be read that way.

Id., p. 24.

The Staff also noted that MCL 460.1173(2) limits a DG customer's generation capacity up to 110% of the customer's electricity consumption for the previous 12 months. *See*, *id*., p. 25. The Staff explained that this section limits a DG customer's production to a reasonable projection of the customer's usage; accordingly, there is no excess production that would need to be covered by the clean and renewable energy standards in Section 79 of Act 235 and, therefore, this issue is not addressed in the statute.

Consumers disagreed with GLREA that the purchase of DG RECs will support REC compliance under Act 235. The company asserted that:

> [b]ecause the average number of megawatt hours of electricity sold by the electric provider reflects the distributed generation that is utilized by the customer and the distributed generation outflow further reduces the sales upon which the Company must comply, the RECs provide no additional value to the Company in achieving RPS compliance as the DG, and the associated RECs, should not be double counted.

2 Tr 122.

In response to GLREA's recommendation that the Commission require Consumers to purchase RECs from DG and PURPA projects prior to purchasing RECs from out of state, the company noted that it already has contracts to purchase certain PURPA RECs. Furthermore, the company argued that GLREA's recommendation to curtail Consumers' ability to purchase RECs from out-of-state providers could result in dormant commerce clause concerns. In any event, the company contended that this issue is not ripe for consideration in this case because it will be addressed in Consumers' VGP filing in the fall of 2025. *See*, Consumers' initial brief, p. 8.

GLREA disagreed with Consumers and the Staff that DG RECs cannot be used for RPS compliance. GLREA stated that "the Commission has already ordered that RECs purchased from DG customers can be used for non-contracted VGP customers in a DTE [Electric Company (DTE Electric)] case," and that the August 22, 2024 order in Case No. U-21374 (August 22 order)

"directed [Consumers] to conduct an outreach session on buying RECs from DG customers. It would hardly make sense for the Commission to order the Company to hold an outreach session on buying something for which the Company had no legal use." GLREA's initial brief, p. 19 (citing the August 24, 2024 order in Case No. U-21172). In response to the Staff's argument that if the Commission approves the use of DG RECs, it should only be outflow RECs, GLREA stated "[w]e agree on that much; it was never our intention to suggest the sale of RECs from DG customer self-consumption; our proposal is concerned with selling RECs from DG *outflow*." *Id*., p. 20 (emphasis in original).

GLREA agreed with the Staff that a REC is the renewable attribute of energy generated from a renewable resource and that, pursuant to Act 235, the DG customer owns any RECs generated on the customer's site. GLREA stated that:

> given that the Company is buying DG outflow *energy* without buying the related RECs (which the law makes clear are owned by the customer) the outflow that the Company is buying is not renewable. Participation in the DG program requires renewable generation, but apparently not the sale of renewable energy. To get renewable energy, the Company would need to purchase the RECs as well. This is one reason that we believe Company witness Johnston is incorrect in his assertion that the subtraction of DG outflow from the Company's load, and buying the REC, would constitute a double-count. Because the law makes it clear that the customer still owns the REC it has not been "counted". The subtraction from the Company's load must represent something else to the legislature. We assert that the subtraction of DG outflow can reasonably be considered an incentive for regulated electric utilities to support the expansion of their DG programs.

Id., pp. 20-21 (emphasis in original). In addition, GLREA asserted that prohibiting DG customers from selling their RECs would be a taking of private property that violates the United States (U.S.) Constitution and the Michigan Constitution. Therefore, GLREA requested that the Commission determine in this proceeding that DG customers may sell the RECs from their outflow and that Consumers may use any RECs it purchases in its non-contracted VGP offering, in its contracted RECs offering, or for RPS compliance.

The ALJ found GLREA's argument somewhat persuasive. However, he agreed with Consumers that "issues related to the structure or operation of the VGP program, like the treatment of RECs from DG customers, should be addressed in the Company's VGP filing." PFD, p. 11. In addition, he noted that in Case No. U-21662, DTE Electric and the Staff suggested that this same issue should be resolved in the VGP filing; the ALJ in that case agreed. Accordingly, the ALJ recommended that the parties revisit this issue in Consumers' upcoming VGP filing.

MEIU excepts, asserting that the ALJ did not consider MEIU's briefing on this issue. MEIU acknowledges that, in this case, it did not provide testimony on this issue but has "submitted extensive testimony and briefing (and at least one petition for rehearing) on the issue in Case Nos. U-21172 (DTE [Electric]'s 2022 VGP case), U-21374 (Consumers' 2022 VGP case), and U-21375 (DTE [Electric]'s 2024 VGP case)." MEIU's exceptions, p. 9. MEIU notes that, in this case, it responded to the Staff's arguments in reply briefing. MEIU states that, "[a]lthough [it does] not disagree with the PFD's recommendation to leave the issue for resolution in Consumers' upcoming VGP proceeding, to the extent that the Commission takes it up here, it should do so with the aid of MEIU's reply briefing." *Id*.

In exceptions, GLREA reiterates that the purchase of RECs from DG customers is consistent with Act 235 and constitutional law. *See*, GLREA's exceptions, pp. 10-18. GLREA again disagrees with the Staff that if DG RECs are purchased and used by the utility, the RECs are double-counted. *See*, *id*., pp. 19-21. Further, GLREA requests that the Commission reject the ALJ's recommendation that this issue be addressed in Consumers' VGP filing in the fall of 2025. Rather, GLREA states, "[a] clear declaration that DG outflow RECs may be purchased and used for RPS compliance is clearly within the scope of this proceeding, as it would provide a new source of RECs for compliance. GLREA also proposes that the Commission order the Company

to include, in its VGP filling this fall, standard contract language for purchase of DG outflow RECs." *Id*., p. 21. Finally, GLREA asserts that the Commission has the duty to protect DG customers and the value of their RECs and should determine that the utility must purchase RECs from DG customers.

Consumers replies, arguing that GLREA "fails to address the crux of the ALJ's determination. The [Commission] has already indicated that this issue will be addressed in the Company's [VGP] filing in the fall. Thus, this issue is not ripe for consideration in this proceeding and GLREA's argument should be rejected." Consumers' replies to exceptions, p. 2 (citing the August 22 order).

After considering the parties' arguments on this issue, the Commission finds the issue is well within the scope of the instant case and, therefore, declines to adopt the ALJ's recommendation to defer a decision on this issue to the VGP proceeding. The Commission also finds the Staff's position on this issue persuasive and that it should be adopted. As noted by the Staff, MCL 460.1028(2) specifically describes how the RPS is to be calculated; the Staff provided an equation to illustrate:

$$RPS\% = \frac{REC_{Requirement}}{Load - Load_{VGP} - DG_{Outflow}}$$

4 Tr 856. The Staff states that "[t]he only two operations that you can do to a fraction or ratio without changing the value is to add zero or multiply by one. If a utility even had the data to add the load back in, it seems as if PA 235 would not allow it as there is no provision to add load back in." 4 Tr 856. The Commission agrees that pursuant to the calculation provided by Section 28(2) of Act 235, Consumers should not purchase RECs associated with DG outflow from customers because it will reduce the amount of total renewable generation required to meet VGP and RPS compliance without simultaneously increasing the denominator with the corresponding generation

from DG outflow. This results in a form of double-counting, as argued by the Staff. Therefore, the Commission declines to adopt GLREA's position on this issue.

b. Landfill Gas Renewable Energy Credits

MEC/NRDC noted that according to Consumers' amended REP, the company plans to use RECs from landfill-gas-fueled generation to comply with the RPS standard. MEC/NRDC stated that pursuant to Section 11(*i*)(i) of Act 235, a utility may meet the renewable energy standards set forth in Section 28 of Act 235 by utilizing RECs from a "renewable energy system," which may include "[a] landfill gas recovery and electricity generation facility located in a landfill whose operator employs best practices for methane gas collection and control and emissions monitoring, as determined by the department of environment, Great Lakes, and energy [(EGLE)]." 2 Tr 400 (quoting MCL 460.1011(*i*)(i)); *see also*, MCL 460.1028. MEC/NRDC contended that Consumers failed to present evidence demonstrating that the proposed landfill-gas-fueled generation RECs comply with the standards in Section 11(*i*)(i) of Act 235 requiring the landfill operator to employ best practices for methane gas collection, control, and emissions monitoring. Accordingly, MEC/NRDC requested that "the Commission adopt practices in the administration of the MiRECS [Michigan Renewable Energy Certification] system that ensure that all landfill gas generation RECs registered in that system, and thereby available for compliance with the renewable energy standard, have documented certification by [EGLE] that the landfill source follows best practices." 2 Tr 401.

Consumers responded that it had "already entered contracts for landfill generation prior to the effective date of [Act 235]." 2 Tr 251. Consumers noted that these contracts are for landfill-gas-fueled generation that comprises approximately 3% of the company's RECs. Consumers asserted that any new landfill-gas-fueled generation contracts will include a provision requiring the facility

to comply with the standards set forth in Section 11(*i*)(i) of Act 235. However, Consumers requested that "it be provided with the opportunity to collaborate with landfill site owners and to consider the options available under current contracts before the Commission determines that the RECs associated with those facilities should not be used for REC compliance." Consumers' initial brief, pp. 9-10. The company stated that if it is unable to use the RECs from its current landfill-gas-fueled generation contracts, Consumers may not be able to meet the RPS targets.

Although MEC/NRDC acknowledged Consumers' concerns, MEC/NRDC argued that the company's claims that it may not meet the RPS targets may be overstated. MEC/NRDC asserted that:

> [f]irst, as noted above, the landfill gas RECs only comprise 3% of the Company's REC portfolio in 2025 – after that, they drop to 2%, then 1%, and then [to] a negligible amount. Second, recognizing that Consumers has not yet determined how these provisions would operate, it appears that four of the Company's seven landfill gas contracts have change in law provisions that could facilitate the Company's efforts to work with landfill owners to ensure compliance with the new standards.

MEC/NRDC's initial brief, p. 41 (citing Exhibits A-34 and MEC-29). In addition, MEC/NRDC contended that Act 235 has no exception for existing contracts that do not contain a change-in-law provision. Therefore, MEC/NRDC requested that the Commission determine "that power purchased from facilities that do not meet the new standards may not be considered renewable energy eligible for REC accrual, and that costs for such purchases may be considered imprudent and disallowed in future REP reconciliation cases." MEC/NRDC's initial brief, p. 42.

Consumers did not dispute MEC/NRDC's assertion that Act 235 now requires landfill-gas-fueled generation facilities to "employ[] best practices for methane gas collection and control and emissions monitoring, as determined by the department of environment, Great Lakes, and energy." Consumers' reply brief, p. 4 (quoting MCL 460.1011(*i*)(i)). However, the company stated that

"there has been no [Commission] or other guidance as to the process for making this 'best practices' determination." *Id*. The company reiterated its request that the Commission provide Consumers time to consider options under its current contracts with landfill-gas-fueled generation facilities before the RECs are excluded or the costs are disallowed in a reconciliation proceeding.

In response, MEC/NRDC asserted that Act 235 does not provide "an indefinite grace period," but "[t]o the extent that Consumers needs a window of time to deal with its landfill contract counterparties, that time is available between now and the reconciliation cases – which is when MEC-NRDC asked the Commission to act on this issue." MEC/NRDC's reply brief, p. 2.

The ALJ agreed with MEC/NRDC that Act 235 requires RECs from landfill-gas-fueled generation to be purchased from facilities that employ best practices as determined by EGLE. The ALJ found Consumers' "request for a grace period unavailing and further notes that the Company should have been on notice since the passage of Act 235 in 2023 that such requirements were going to be necessary in order for Landfill Gas RECs to be used to meet the RPS." PFD, pp. 13-14. Thus, the ALJ recommended that the Commission find that power purchased from landfill-gas-fueled generation facilities that do not employ best practices certified by EGLE is not eligible for RECs, that the purchase of such power may be found to be imprudent, and that the costs may be disallowed in an REP reconciliation case.

Consumers excepts, arguing that "(1) additional guidance is needed to determine how to comply with the new statutory requirement and (2) cost recovery for these PPAs [power purchase agreements] has been previously approved by the Commission pursuant to various statutory provisions." Consumers' exceptions, p. 4. The company asserts that it is not clear from the statutory language what constitutes "best practices," what type of "certification" is required to comply with "best practices," whether EGLE would provide the certification, if a statement from

the landfill gas operator would be equivalent to a certification, and, if so, what the statement should include. *See*, *id*.; *see also*, MCL 460.1011(*i*)(i).

Additionally, Consumers contends that it pays for and receives energy and/or capacity pursuant to the terms of existing landfill gas PPAs. The company states that "[e]ven if it is eventually determined that RECs are not available for use in the RE [renewable energy] Plan from any of these PPAs, that does not invalidate the previously approved agreements and does not provide for a disallowance of the energy and capacity costs paid under those agreements." Consumers' exceptions, p. 5.

MEC/NRDC reply that "[w]hile [it does] not disagree that guidance regarding the required certification for landfill gas operators would be beneficial, the law no longer provides for landfill gas RECs sourced from facilities other than those that use best practices for methane collection and control and emissions monitoring." MEC/NRDC's replies to exceptions, p. 2. Accordingly, MEC/NRDC request that the Commission adopt the ALJ's recommendation.

The Commission finds that to meet the REC standard under Act 235, an electric provider may obtain RECs from several sources, including a "renewable energy system." *See*, MCL 460.1028(5). According to Section 11(*i*)(i) of Act 235, a landfill gas recovery facility is a "renewable energy system" if it "employs best practices for methane gas collection and control and emissions monitoring, as determined by the department of environment, Great Lakes, and energy." MCL 460.1011(*i*)(i). As stated in Section 11(*i*)(i) of Act 235, "best practices" are to be determined by EGLE. The Commission encourages the parties to work with EGLE to develop best practices for landfill gas recovery facilities. In addition, the Commission expects that, to qualify for the REC standard under Act 235, any new landfill gas PPAs, or renewals of existing

landfill gas PPAs, must be executed with a landfill gas facility that employs best practices as defined by EGLE.

The Commission agrees with Consumers that, prior to the enactment of Act 235, several landfill gas PPAs and the associated cost recovery were approved by the Commission in previous cases. The Commission also agrees with the company that determining REC eligibility in an REP for landfill-gas-fueled generation does not affect the recovery of energy and capacity costs paid by Consumers under those landfill gas PPAs. Rather, the determination of the reasonableness and prudence of the energy and capacity costs for the landfill gas PPAs would occur in a power supply cost recovery (PSCR) proceeding.

c. Incentive Renewable Energy Credits

i. On-Peak and Off-Peak Incentive Renewable Energy Credits

MEC/NRDC noted that Section 39(2) of Act 235 "requires the granting of certain quantities of incentive RECs under five different circumstances, including a '1/5 renewable energy credit for each megawatt hour of electricity generated from a renewable energy system, other than wind, at peak demand time as determined by the commission' under subsection (b)." MEC/NRDC's initial brief, pp. 20-21 (quoting MCL 460.1039(2)(b)). MEC/NRDC stated that:

> Consumers has calculated incentive RECs for electricity generated from a renewable energy system, other than wind, at peak demand time using on-peak hours as previously defined by MISO [Midcontinent Independent System Operator, Inc.] -0600 through 2200 EST [Eastern Standard Time], excepting weekends and some holidays. MCL 460.1039(2)(b) states that peak demand time is to be determined by the Commission. The Commission referenced this definition in its December 4, 2008 temporary order in Case No. U-15800 [(Temporary Order)].

2 Tr 432 (citing Exhibit MEC-9) (footnotes omitted).

MEC/NRDC asserted that the temporary order in Case No. U-15800 is now 16 years old and the grid has significantly changed, including the addition of intermittent renewables, which will

continue to be added to MISO Zone 7. MEC/NRDC stated that "[w]hile avoiding any legal interpretation of the governing law, it is reasonable to assume that the intention of providing incentive RECs for non-wind renewable generation technology was to support the build-out of generation that would benefit the grid in its most constrained hours. The current definition does not do this." 2 Tr 432. MEC/NRDC requested that the Commission reconsider the hours of peak demand for purposes of calculating incentive credits pursuant to Section 39(2)(b) of Act 235.

Consumers responded that it "has no choice but to follow the Commission direction provided in its December 4, 2008 temporary order in Case No. U-15800. The Company has calculated and presented its incentive REC[s] in each of its renewable cost reconciliations since 2009 in accordance with the Commission direction." 2 Tr 106. In addition, the company disagreed with MEC/NRDC's recommendation that a change to the hours of peak demand should be made in this case. Rather, Consumers stated that any change to the peak demand time should involve other utilities and should be considered and thoroughly reviewed in an industry workgroup.

The Staff stated that "there are discussions of updating this definition within MISO," and it may "be premature to update the current definition at this time." 4 Tr 808. In addition, the Staff noted that because this definition affects all electric providers, any update to the definition should include input from all affected utilities and interested persons. The Staff recommended that "this discussion take place in a standalone workgroup or in the transfer price workgroup suggested above. However, updating this definition in advance of a potential MISO definition update may result in a need to update the definition again in the future." 4 Tr 808.

MEC/NRDC asserted that Consumers and the Staff failed to provide a compelling reason to continue using the outdated definition of "peak demand time" set forth in the Temporary Order. MEC/NRDC reiterated that the Temporary Order is 16 years old, was not intended to be

permanent, should not be relied upon as precedent, is inconsistent with MISO's tariff definition, and conflicts with the language of Act 235. *See*, MEC/NRDC's initial brief, pp. 22-27.

The ALJ agreed with MEC/NRDC that the definition of "peak demand time" in the Temporary Order is outdated, but he declined to recommend that the Commission reject Consumers' calculation of incentive RECs. The ALJ stated that "it would be unreasonable to implement a new definition in this case when this is an industry-wide issue. Accordingly[,] this PFD recommends that the Commission create a workgroup to develop an updated definition of peak demand time to be used in calculating incentive RECs under subsection 39(2)(b)" of Act 235. PFD, p. 16.

MEC/NRDC excepts to the ALJ's recommendation that the Commission reject MEC/NRDC's proposal and, instead, defer the decision to a workgroup. MEC/NRDC asserts that "doing so would mean approving an incentive REC calculation based on a methodology that is not supported by substantial evidence." MEC/NRDC's exceptions, p. 2. In addition, MEC/NRDC contends that it is not necessary to involve all utilities in a discussion to define peak demand time. MEC/NRDC states that "[t]he Commission routinely establishes precedent in contested cases involving one utility that it later applies in cases involving other utilities. Nothing requires all utilities governed by a statute to be parties to any case in which that statute is interpreted and applied." *Id*., p. 3 (citing the July 2, 2024 order in Case No. U-21461, pp. 84-87). Moreover, MEC/NRDC argues that it is unclear when or how the proposed workgroup will resolve this issue. Therefore, MEC/NRDC asserts that the Commission should adopt MEC/NRDC's proposed definition because it "is reasonable and well aligned with the statute's purpose. No party presented evidence to the contrary, nor did any party recommend a better or even different definition." *Id*., p. 4.

In reply, Consumers states that its calculation of incentive RECs is supported by substantial evidence and that the definition of on-peak hours is being considered by the workgroup established in Case No. U-21662. The company notes that although MEC/NRDC expressed concern about the certainty of a decision in the workgroup:

> the Commission ordered Staff to "submit to the Commission a final report no later than September 1, 2025." The Commission will then determine how to proceed regarding this issue. In the meantime, the Commission should not make any determinations in this case regarding on-peak incentive RECs that would disrupt the workgroup process that is already ongoing, and the Commission should reject MEC's proposal to adopt its definition of "peak demand time" in this case.

Consumers' replies to exceptions, p. 4 (quoting the May 15, 2025 order in Case No. U-21662 (May 15 order), p. 4; citing the August 7, 2025 order in Case No. U-21662).

The Commission notes that in the May 15 order, it directed the Staff to, among other things, "convene a workgroup to revise the definition of on-peak hours for the determination of incentive renewable energy credits no later than June 7, 2025, with a report to be filed with the Commission by September 1, 2025." May 15 order, p. 4. The Staff hosted an online symposium on June 5, 2025, at which the Staff and a representative from 5 Lakes Energy provided presentations, and numerous interested persons were in attendance. The Commission notes that the Staff and interested persons explored the issue of "peak demand hours" for incentive RECs, and that the required report was timely filed in the docket for Case No. U-15800 on August 29, 2025. *See*, filing #U-15800-0066 in Case No. U-15800. With the final report now filed, the Commission expects to provide guidance for all affected utilities on this issue in the near future.

In the immediate case, the Commission agrees with Consumers that the company is required to comply with the directives of the Temporary Order. Therefore, the Commission finds that Consumers' proposed incentive RECs, as calculated using the "peak demand hours" set forth in the Temporary Order, are approved for 2023. However, until the Commission receives the final

report to be issued on September 1, 2025, in Case No. U-15800, and determines whether any adjustments should be made to how incentive RECs are calculated, the Commission declines to approve Consumers' incentive RECs for 2024-2045.

ii. Off-Peak Generation for Storage Incentive Renewable Energy Credits

MEC/NRDC also objected to Consumers' calculation of incentive RECs for electricity generated from a renewable energy system during off-peak hours, stored in an energy storage system or hydroelectric pumped storage facility, i.e., the Ludington Pumped Storage Plant (Ludington), and then used during peak hours. MEC/NRDC noted that in the Temporary Order, "the Commission approved a method for calculating the storage incentive REC based on the lesser of the renewable energy generated during off-peak hours and the energy used to charge the storage system:

> Advanced Electric Storage Technologies or Hydro Electric Pumped Storage Facilities.
>
> Pursuant to Section 39(2)(c) [of Act 235], the Michigan Incentive REC is determined to be the renewable and/or advanced cleaner energy that is generated during the off-peak period and used to charge the Advanced Electric Storage Technology, or fill the Pumped Storage Facility on an hourly basis. The determination of this value for each off-peak hour shall be the lesser of (1) the sum of the net renewable and advanced cleaner energy that is generated during each off-peak hour, or (2) the energy used to charge the Advanced Electric Storage Technology or fill the Pumped Storage Facility during each off-peak hour.

MEC/NRDC's initial brief, p. 29-30 (quoting Temporary Order, p. 28). MEC/NRDC asserted that the method in the Temporary Order fails to accurately estimate the amount of renewable energy that is used to fill the storage reservoirs. According to MEC/NRDC:

> [w]hen Ludington pumps water to fill the reservoirs, "that power is drawn from the MISO grid and adds to the load that MISO serves." In other words, the power needed to fill Ludington is incremental load – requiring additional generation beyond what MISO is already operating when Ludington turns on. The additional generation to fill Ludington comes from the next resource in the economic dispatch sequence. Unless renewables are being curtailed on the system at that time, the

> next generating resource to dispatch will be [sic] not be renewable – it will be a conventional generating plant with marginal costs. Hence, it is unreasonable to assume that all renewable generation operating at the time of pumping is used to pump Ludington. Instead, the Commission should determine that electricity generated from a renewable energy system during off-peak hours is stored in Ludington only when renewable resources are on the margin when Ludington is pumping, and otherwise would have been curtailed if Ludington was not pumping.

MEC/NRDC's initial brief, p. 31 (quoting 4 Tr 435). MEC/NRDC stated that if the Commission were to adopt its recommendation, Consumers' incentive RECs will need to be recalculated and, as a result, the amount of incentive RECs will be materially reduced.

Consumers disagreed with MEC/NRDC, stating that:

> [r]egardless of whether the marginal resource is renewables, power flows in the path of least resistance and unless the marginal resource is located adjacent to the Ludington Pumped Storage Facility, it is unlikely that it is serving the electric load instead of renewables. The fact of the matter is that the Company's Lake Winds Energy Park is in Ludington and, when it generates and the reservoir is being filled, it is likely the source of that electric power.

2 Tr 106. In addition, the company asserted that it is not reasonable to assume that the pumping load at Ludington is exclusively served by marginal market resources. Consumers averred that, for Ludington, the company bids the pumping load in the day-ahead submittal and receives almost the same locational marginal price that other load sources receive.

Noting that the electric energy that serves the pumping load at Ludington is not tracked, MEC/NRDC argued that it cannot be definitively determined that the facility is being charged by renewable resources. MEC/NRDC stated that Section 39(c) of Act 235 "requires that the incentive RECs 'shall be calculated based on the number of megawatt hours of renewable energy used to charge the energy storage system or fill the pumped storage facility . . . [.]' If Consumers does not know how many megawatt hours that is, there is no substantial evidence to support the company continuing to claim incentive RECs using the current calculation." MEC/NRDC's initial brief, p. 33 (quoting MCL 460.1039(2)(c)).

MEC/NRDC also asserted that in the settlement agreement approved by the May 15 order, the parties agreed that the Commission should consider revising the directives in the Temporary Order concerning incentive RECs related to energy storage systems and hydroelectric pumped storage facilities. MEC/NRDC noted that "the Commission did not expressly address the settlement term in its Order approving the settlement. MEC-NRDC believe the omission may have been an oversight . . . ." MEC/NRDC's initial brief, p. 34.

The ALJ acknowledged MEC/NRDC's argument on this issue, but:

> recognize[d] that Ludington is co-owned by Consumers and DTE Electric and, as such, any resolution of the issue of incentive RECs association with that facility should be applicable to both utilities. Accordingly, and consistent with this PFD's determination on subsection 39(2)(b) [of Act 235] and with the settlement agreement in Case No. U-21662, this PFD recommends that this issue be addressed in an industry-wide workgroup.

PFD, p. 19.

MEC/NRDC excepts, reiterating that Consumers failed to demonstrate that the calculation of storage incentive RECs is reasonable. In addition, MEC/NRDC disputes the ALJ's determination that the settlement agreement in Case No. U-21662 recommended a workgroup for storage incentive RECs. MEC/NRDC notes that the August 7, 2025 order in Case No. U-21662 appeared to recommend that this issue be discussed in a transfer price and peak demand symposium. According to MEC/NRDC, the symposium is complete and "no decision or recommendation has been made on this issue. It is unclear at this point what the path is now to a decision on this issue via the workgroup process." MEC/NRDC's exceptions, p. 9 (citing the August 1, 2025 Draft Staff Report in Case No. U-15800). Therefore, MEC/NRDC request that the Commission direct Consumers to rework the method for calculating storage incentive RECs consistent with MEC/NRDC's recommendations.

As noted by the ALJ, the Ludington Pumped Storage Plant is jointly owned by Consumers and DTE Electric. The Commission finds that it would be imprudent to make a determination regarding incentive RECs in this case, which would also affect DTE Electric. This issue was discussed in the workgroup ordered by the May 15 order and the final report filed on August 29, 2025, in Case No. U-15800. As noted above, with the final report now filed, the Commission expects to provide guidance to all affected utilities on this issue in the near future.

d. Renewable Energy Credit Market Purchases (Renewable Energy Credit Only Contracts)

Consumers stated that it plans to meet RPS targets with "RECs provided from market purchases according to Act 235, Section 28(5)(c) permitting procurement of not more than 5% of RECs to comply with the renewable energy standard. This 5% RECs provision cannot be used to comply with the renewable energy standard after 2035." 2 Tr 243.

MEC/NRDC objected to Consumers' RECs purchased on the open market, asserting that although these RECs constitute a small part of the company's portfolio, they are expensive. MEC/NRDC noted that:

> [f]rom 2026 through 2035, Consumers plans to purchase 7,013,979 RECs at a cost of $14.03 million at a projected cost of $2 per REC. This compares to an average REC cost from Consumers-owned or PPA-purchased RECs of $.35; this is over a five-fold difference in price between Consumers' projected price for market-purchased RECs and its projected price for other REC sources.

2 Tr 419 (citing Exhibit A-38). MEC/NRDC also noted that DTE Energy (DTE) assumes a higher rate for its market purchases of RECs: "[f]or project RECs purchased prior to 2030, DTE assumes a cost of $3/REC, with $5/REC assumed in all years from 2030 and beyond." 2 Tr 419 (citing Exhibit MEC-5). MEC/NRDC stated that DTE expects the Midwest REC market to tighten because there will be greater obligations under the RPS standards in Michigan, Minnesota, and Illinois in the next 15 years. MEC/NRDC contended that, if Consumers were to "[use] the same

assumptions as DTE, Consumers would need to spend $33.07 million on the same number of RECs increasing their market-purchased REC, to other REC cost ratio to over 13 to 1." 2 Tr 419.

In addition, MEC/NRDC asserted that market-purchased RECs are not necessary for Consumers to comply with the renewable energy standard from the present year to 2035. MEC/NRDC stated that, according to Consumers, the company "expects to build a REC balance of 12.4 million RECs by 2045. This is more than the total number of RECs purchased at market prices between 2026 and 2034." 2 Tr 421 (footnote omitted). Therefore, MEC/NRDC requested that Consumers be prohibited from preemptively purchasing, or planning to purchase, open-market RECs; rather, the open-market RECs should only be purchased in the event that Consumers has a short-term risk of not complying with the RPS. However, in the event the Commission approves Consumers' purchase of open-market RECs, MEC/NRDC recommended that the Commission condition the approval on the RECs being Green-e® certified.[1] *See*, 2 Tr 420.

Consumers responded that it is unclear how MEC/NRDC calculated the average cost of $0.35 per REC for PPAs but noted that MEC/NRDC appears to reference Exhibit A-38. The company stated that, for the REC costs proposed in Exhibit A-38, it "does not allocate any expense for RECs generated from Company-owned renewable energy resources or a cost for incentive RECs as part of the Average REC Cost calculation in Exhibit A-38 (CCO-6)." 2 Tr 248-249. In any event, Consumers asserted that Section 28(5)(c) of Act 235 permits:

> electric providers to meet the REC Standard with RECs obtained from purchasing RECs without the associated renewable energy or capacity, with the only limitation being that the RECs (i) must be "produced within the territory of the regional transmission organization of which the electric provider is a member," (ii) must not

[1] A REC is created for each MWh of renewable electricity generated by wind, solar, biomass, geothermal, and certain hydropower sources and then delivered to the power grid. Green-e® is an independent consumer protection program that tracks, accounts for, and certifies the environmental benefits of RECs and verifies that the electricity was produced without burning fossil fuels.

> "exceed 5% of an electric provider's [RECs] annually used to comply with the renewable energy standard," and (iii) cannot be used to comply with the REC Standard after 2035. Accordingly, the Company included these market purchases of RECs as part of its plan to meet the renewable energy targets consistent with the limitation in MCL 460.1028(5)(c).

Consumers' initial brief, p. 12 (citing 2 Tr 243).

In addition, the company disagreed with MEC/NRDC that open-market RECs should only be used to remedy short-term risk of non-compliance with the REC portfolio standard. Consumers contended that there are other risks identified in the company's REP, "such as siting, tariffs, interconnection, sales uncertainty, price uncertainty, and tax credits. The Company is planning for these REC-only purchases as a cost-effective way to ensure REC compliance is achieved." 2 Tr 250. Furthermore, Consumers asserted that it is not necessary to require that the open-market RECs have Green-e® certification. The company explained that MIRECS is a "sophisticated tracking system" that "protect[s] the integrity of the RECs as well as prevent[s] any double counting." 2 Tr 249.

MEC/NRDC acknowledged Consumers' testimony that it does not allocate any expense for RECs generated from company-owned renewable energy resources or the cost for incentive RECs as part of its Average REC cost calculation and stated that, based on this information, MEC/NRDC's calculated average cost of $0.35 per REC for PPAs may be inaccurate. However, MEC/NRDC maintained that open-market purchased RECs "are still far too expensive for the value they provide, which, for ratepayers is essentially zero – market-purchased REC[s] simply allow Consumers to buy compliance for itself with no associated renewable energy or capacity for its customers." MEC/NRDC's initial brief, p. 18.

In response to Consumers' claim that open-market purchased RECs do not need to be Green-e® certified because of the MIRECS system, MEC/NRDC asserted that REC tracking is not

the only benefit of Green-e® certification; rather, the certification "also ensures quality and support for new renewable energy generation." *Id*. (citing 2 Tr 420). MEC/NRDC also disputed the company's assertion that the purchase of open-market RECs mitigates other risks in Consumers' REP and provides flexibility to build a larger REC bank. According to MEC/NRDC, "there are better ways to reduce the risk Consumers says it is concerned about – for example, it can procure more wind generation sooner and use PPAs for both in- and out-of-state wind . . . ." MEC/NRDC's initial brief, p. 18.

The ALJ noted that Section 28(5)(c) of Act 235 "explicitly allows electric providers to meet up to 5% of the RPS requirements through 2035 by purchasing market RECs. If the Legislature intended to place more or different restrictions on the acquisition of these RECs, as MEC-NRDC recommends, it would have done so in the Act." PFD, p. 22. However, the ALJ stated that Consumers has an obligation to demonstrate in its REP reconciliation proceeding that open-market purchases of RECs are reasonable, prudent, and necessary to comply with the RPS. Furthermore, the ALJ noted that Section 28(6) of Act 235 requires the Commission to review REC-only contracts. Therefore, the ALJ asserted that "there are appropriate mechanisms to ensure that the use of market RECs is warranted and is reasonable and prudent." PFD, p. 22. The ALJ recommended that the Commission decline to approve MEC/NRDC's amendments to Consumers' open-market REC purchase proposal.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation to be reasonable and prudent and that it should be adopted. The Commission also finds Consumers' argument persuasive that it is not necessary to require that the open-market RECs have Green-e® certification. MIRECS includes

the unique serial numbers of the RECs, transaction data, complete audits, and exclusive tracking, which is sufficient to ensure quality and prevent the risk of double-counting.

2. Resource Additions

a. Purchased and Company-Owned Solar Energy Resources

GLREA expressed concern that the transmission-connected solar facilities in Consumers' REP would be required to go through the MISO interconnect process, which may result in build schedule delays and possible non-compliance with statutory deadlines for the RPS. GLREA asserted that:

> [b]ecause the distribution system cannot host generating facilities as large as those in the current build plan, this approach would also require soliciting smaller projects. This reduces schedule risks in two additional ways: it means that the delay of any single project has less impact, and smaller facilities are less likely to encounter local opposition, reducing siting risks. In some cases, the Company may own sufficient land to support a smaller solar facility, eliminating the requirement to acquire land rights. Smaller solar facilities may also mitigate the transformer supply risk by using smaller transformers.

4 Tr 579. In addition, GLREA contended that connecting generation facilities to the distribution grid has the benefit of avoiding the cost of transmission, energy losses in transmission, and line losses. Furthermore, GLREA stated that "[t]argeting the location of the installation to connect at a substation that is under stress may also allow the delay or avoidance of an expensive substation upgrade." 4 Tr 579. Therefore, GLREA recommended that the Commission direct Consumers to, in its next solicitation, "include an option for a distribution-connected pilot, with a list of connection points in which the addition of generation would support the distribution grid, and the capacity of generation each interconnection point could support." 4 Tr 581. In the alternative, GLREA requested that the Commission direct the company to provide a contract for smaller, under 5 megawatts (MW) distribution-connected, solar facilities that are priced based on recent company solicitations, similar to those set forth in DTE Electric's recent REP, Case No. U-21662.

MEC/NRDC stated that it supports "competitive procurement of renewables on a non-discriminatory basis, in order to obtain the best value for utility customers and overcome the bias toward utility-owned resources that is inherent in rate-of-return utility regulation." 2 Tr 409. However, MEC/NRDC noted that, according to Consumers, the risks for developing renewable energy systems that comply with the RPS include the MISO interconnection queue and siting of the renewable energy systems. In MEC/NRDC's opinion, the impediment of the MISO interconnection queue can be avoided by building small projects that are interconnected with the company's distribution system. Additionally, MEC/NRDC asserted that larger projects usually encounter "greater siting opposition within a host community." 2 Tr 410. Therefore, MEC/NRDC recommended that the Commission allow Consumers, pursuant to MCL 460.1028(6), to use standard-offer contracts for small projects that may be developed without participating in the competitive bidding process, such as build-and-transfer agreements (BTAs) and PPAs. MEC/NRDC "recommend[ed] that the prices offered for such standing offer contracts be calibrated from time-to-time based on the prices of projects selected in Consumers['] . . . competitive bidding processes but adjusted for differences in line losses between the project location and the physical load served by the project versus line losses between large projects and the physical load they serve." 2 Tr 412.

MEIU contended that the Commission should allow mid-size solar projects, specifically in settled areas, of up to 10% of total incremental solar resource additions over the relevant three-year period. MEIU explained that:

> [m]id-size projects are large enough to leverage economies of scale enjoyed by utility-scale systems, so they can be developed at costs that are highly competitive. Unlike larger-scale resources, however, and not unlike behind-the-meter resources, mid-size projects can be flexibly located and can provide distributed benefits including avoided transmission line losses, deferral of distribution infrastructure upgrades, and increased system resilience. Because mid-size projects have an

> opportunity to interconnect to medium-voltage (MV) distribution systems, the interconnection process also has the potential to be more streamlined and less expensive, as system impact studies for distribution-level projects can be simpler and more straightforward than similar studies for utility-scale projects. Mid-size projects can also take advantage of the expanded federal Investment Tax Credit ("ITC") for interconnection costs for smaller-output facilities (<5 MW), further lowering costs.

4 Tr 658-659 (footnotes omitted).

The Staff stated that it is "intrigued by [MEIU's] discussion asserting that smaller scale projects can be cost effective due to avoidance of transmission interconnection costs. As such, Staff could be supportive of a small-scale solar program or Community Solar Program (both 5 MW and under) standard offer program that resulted in reasonable costs to the Company." 4 Tr 816. However, the Staff expressed concern that smaller projects are less cost competitive and require subsidization. The Staff asserted that:

> [o]ne potential measure of the reasonableness of such costs could be that they be compensated through a tariff equal to the levelized cost of a selected Company-owned renewable project or PPA in the Company's most recent RFP [request for proposal] solicitation, and in the case of a Community Solar program, the tariff rate would subtract out the costs to establish participant bill crediting. This would enable a test of the theory that small distribution voltage interconnections provide cost savings over transmission interconnections. Additionally, any Community Solar program should count towards the 10% distributed generation (DG) cap as this program should be designed in a manner that provides a DG option for those that are unable to install DG themselves such as renters, wooded lots, economics, etc.

4 Tr 816.

Consumers contended that although its modeling assumes a levelized cost of energy (LCOE) based on transmission-connected facilities, "[t]he Company intends to continue to allow distribution connected facilities in its annual RFPs and will continue to consider them on the same basis as transmission connected projects. To the extent that distribution connected facilities can provide timely and economic renewable energy resources, they will be considered for selection."

2 Tr 359. Consumers noted that, historically, the smallest size project that could participate in the company's RFP is 0.15 MW alternating current (MWac) for PURPA-qualified facilities and 1 MWac for non-PURPA-qualified facilities. The company asserted that it "has signed multiple PURPA contracts for resources less than 5 MW in each of the last three years." 2 Tr 362.

Consumers disagreed with MEIU's recommendation that the Commission allow a procurement carveout of up to 10% for midsize solar resources. The company stated that MEIU "appear[s] to be arguing the economic benefits of mid-size (1-5 MW) resources. Assuming this to be true, then there would be no need to create a carveout specifically for mid-size (1-5MW) resources in the Company's RFPs because these resources can participate, and based on this claim, should be economically competitive." 2 Tr 364.

Consumers acknowledged MEIU's claim that there may be non-economic benefits to mid-size projects. However, the company stated that it has not conducted system-wide detailed modeling for these projects, which would be better performed in the company's integrated resource plan (IRP). In addition, Consumers contended that a 10% carveout for mid-size projects is not necessary because the company "allows distribution connected projects to bid into RFPs and utilizes distribution specific assumptions for modeling the economics of distribution projects in RFPs." 2 Tr 364.

Consumers contended that although MEIU claims that the carveout may reduce the risk for RPS non-compliance, MEIU did not consider the cost of risk avoidance. The company noted that it has not performed an RPS non-compliance risk assessment either. In any event, Consumers stated that if it "experiences significant delays or changes to its plan which impact its ability to maintain RPS compliance, the Company will assess its options for maintaining RPS compliance at that time, using more recent and relevant data than what might be provided in this case." 2 Tr 365.

GLREA noted that it would support the Staff's proposal, with one adjustment, for a small-scale solar program or community solar program (both 5 MW or smaller) standard offer program that resulted in reasonable costs to Consumers. GLREA asserted that "[i]f there is to be a tariffed standard offer, the contract price should have an adder equal to the cost of using the transmission network (the fee the Company pays to ITC [Holdings Corp.]), and an adjustment for transmission line losses. Both of these costs are directly avoided with a distribution-connected system." GLREA's initial brief, p. 14.

In response to Consumers' claim that it allows bids for distribution-connected facilities as small as 1 MWac, GLREA argued that this is insufficient. According to GLREA, Consumers' proposal "fails to recognize the cost savings of avoiding the transmission system" that are "directly financially quantifiable." *Id*., pp. 14-15. Although GLREA acknowledged that interconnection to the distribution system is not cost-free, it is more rapid, which results in cost savings. Additionally, GLREA asserted that there are non-financial benefits to distribution-connected facilities such as company control over the planning process and interconnection schedule as compared to the lengthy MISO interconnection process.

GLREA contended that distribution-connected facilities are at a disadvantage competing in the same solicitation as transmission-connected facilities, that there should be a separate solicitation, and that it be conducted as a pilot program similar to Consumers' substation-connected battery systems pilot. Furthermore, GLREA asserted that Consumers "has not provided any means for developers to know what parts of their distribution system could support a substantial solar generation facility," and requested that the company provide this information. *Id*., p. 16.

MEC/NRDC objected to Consumers' claim that it already offers an opportunity for small-size projects to participate in the RFP through PURPA. MEC/NRDC asserted that "PURPA is not an

economically viable avenue for the kinds of small projects witness Jester described because it does not offer pricing that is comparable to that available in the RFPs – if the small projects had any chance of competing with large greenfield projects in the first place." MEC/NRDC's initial brief, p. 38.

The ALJ agreed with GLREA and MEC/NRDC that distribution-connected solar could provide greater benefits than transmission-connected solar and that Consumers failed to provide persuasive reasons to reject GLREA's and MEC/NRDC's proposals to facilitate smaller projects. Therefore, the ALJ:

> [r]ecommend[ed] that the Commission order that in its next solicitation, the Company include an option for a distribution-connected pilot, with a list of connection points in which the addition of solar generation would support the distribution grid, and the capacity of generation each interconnection point could support. In the alternative, the Commission could direct the Company to create a standard contract for smaller, distribution-connected solar facilities (under 5 MW), with pricing based on recent Company solicitations.

PFD, p. 27.

In exceptions, Consumers asserts that the intervenors have not demonstrated that it is necessary or reasonable to include distribution-connected solar facilities in the company's next solicitation, to create a standard contract for smaller, distribution-connected solar facilities, or that these are necessary to comply with the RPS. The company contends that "[s]maller distribution connected facilities are already able to participate in the Company's competitive solicitations and [Consumers] utilizes distribution specific assumptions for modeling the economics of distribution projects in Requests for Proposals ('RFPs')." Consumers' exceptions, p. 6. Consumers states that it will continue to allow distribution-connected facilities to participate in its annual RFPs and the company will provide the same consideration to distribution-connected projects as is offered to transmission-connected projects.

MEIU objects to the ALJ's alternative recommendation that the Commission direct Consumers to create a standard contract for smaller, distribution-connected solar facilities with pricing based on recent company solicitations. MEIU contends that the ALJ's recommendation that "pricing should be 'based on recent Company solicitations' (presumably referring to recent solicitations for large, transmission-connected projects) presents challenges to the viability of its overall recommendation." MEIU's exceptions, pp. 2-3 (quoting the PFD, p. 27). According to MEIU, smaller projects are unable to equitably compete with larger projects and, therefore, a procurement carveout or pilot is necessary to level the field. In addition, MEIU asserts that small-to-mid-size distribution-connected projects provide additional benefits that may offset the higher project costs, which are not addressed by simply providing a standard contract, as recommended by the ALJ. Thus, MEIU requests that the Commission adopt the ALJ's recommendation that Consumers include, in its next solicitation, an option for a distribution-connected pilot, as described by the ALJ. However, MEIU states that the pricing for that option should not be limited to the company's recent solicitations.

GLREA asserts that it is grateful that the ALJ recommended adoption of GLREA's distribution-connected pilot solicitation proposal. However, GLREA contends that the ALJ misstated GLREA's position, which was corrected in GLREA's brief. GLREA explains that:

> [t]he MEC-NRDC proposal is explicitly for systems under 5 MW and located in settled areas, on brown fields, and for agrivoltaics projects. GLEA's [sic] proposal does not have locational restrictions, and can apply to much larger systems, limited in size only by the engineering limit that the distribution system can support. GLREA's discovery asked the Company how large of a solar facility their distribution system could support. The Company responded that they didn't know. A third-party analysis of the Company's grid suggests 30-50 MW generation facilities can be supported by circuits of 25 to 34 kV [kilovolts]. The Company is deploying one 30 MW and one 45 MW battery storage system at its Weadock and Iosco substations (respectively), demonstrating that the Company's distribution system can support power inputs that large. Due to economies of scale, it can be expected that successful bidders in a pilot for distribution connected solar facilities

> would consist of projects in the tens of megawatts. For that reason, the solar projects which might be built under the MEC-NRDC proposal (< 5 MW) and those projects which might be built under GLREA's separate solicitation proposal, would not overlap. The two proposals are complementary and would support different projects. Both are worthy of adoption.

GLREA's exceptions, p. 24 (citing 2 Tr 412; 4 Tr 600-602). Accordingly, GLREA requests that the Commission adopt its proposal for a distribution-connected pilot solicitation and MEC/NRDC's complimentary proposal.

In response to Consumers' exceptions, MEIU asserts that the company "has still by no means established that its current procurement processes are sufficient for recognizing the full value offered by distribution-connected solar, value [sic] which, as MEIU discuss in their own Exceptions, the PFD also recognizes." MEIU's replies to exceptions, p. 2.

Consumers replies that, as set forth in the company's exceptions, the Commission should reject MEIU's and GLREA's proposals. Consumers states that "[t]here has not been a showing that these proposals are necessary or reasonable. Nor has there been a showing that these proposals are necessary to comply with the REC standard. The Company has options in place for these smaller projects and the ALJ's recommendation should be rejected." Consumers' replies to exceptions, p. 6.

In response to Consumers' claim that GLREA's proposal is unreasonable and unnecessary and does not comply with the REC standard, GLREA contends that it provided sufficient evidence on the record to support its proposal. *See*, GLREA's replies to exceptions, pp. 1-3. Additionally, GLREA continues to object to the company's claim that it allows distribution-connected facilities in its annual RFPs and that Consumers provides the same consideration to distribution-connected facilities as it does for transmission-connected projects. GLREA reiterates the arguments set forth in testimony and briefing. *See*, *id*., pp. 4-5.

The Commission respectfully declines to adopt the ALJ's recommendation. The Commission agrees with the parties that there could be cost savings with smaller scale, distribution-connected projects and, in the absence of cost savings, other benefits such as reducing the risk of RPS noncompliance and distribution system benefits—albeit at the cost of a potentially higher bid. Thus, the Commission encourages the company to find opportunities for these projects, and the associated benefits, to be considered. However, the Commission finds that there was insufficient evidence on the record to establish a reasonable and prudent standard offer and, therefore, the Commission is not directing the company to provide a particular standing offer contract. Without a more robust evidentiary record and definition and quantification of the purported benefits of these smaller scale projects, there is a risk that the company may overpay for projects when the benefits may not offset the higher costs compared to larger projects. Accordingly, the Commission finds that Consumers should ensure that enough information is provided in response to intervenor requests to allow for a robust benefit analysis, should continue to ensure that small-scale distribution-connected projects are able to participate in the competitive bidding process, and should utilize distribution-specific assumptions for modeling the economics of distribution projects in RFPs.

b. Company-Owned Wind Energy Resources

Consumers proposed to amend its REP to include up to 2,800 MW of both purchased and company-owned solar energy resources that are consistent with Consumers' IRP approved by the June 23, 2022 order in Case No. U-21090 (June 23 order) and that comply with REC requirements for 2030 and 2035. The company stated that it:

> has modeled the assets for its Amended RE Plan to all be sourced within Michigan, MISO Zone 7. However, to the extent that the Company is able to identify out of state renewable energy resources that are more financially viable than Michigan renewable energy resources due to factors such as construction cost or capacity

> factor, the Company will consider executing purchased power agreements for those assets; the Company does not intend to own out of state renewable energy resources.

2 Tr 59-60.

MEC/NRDC disagreed with Consumers' wind-build proposal for several reasons. First, MEC/NRDC contended that the company's Michigan wind-build proposal of 1,500 MW for 2032 and 800 MW for 2035 is unrealistic because "[i]n the history of wind energy development in Michigan, there has never been a year with more than 600 MW of new wind brought onto the grid." 2 Tr 422. In addition, MEC/NRDC stated that if the company delays its major wind projects until 2032 and 2035, the best wind resources in Michigan will be acquired by other utilities. Instead, MEC/NRDC recommended that Consumers "develop wind generation resources sooner and at a more even pace and by actively looking to acquire a portion of its wind energy through power purchase agreements (PPAs)." 2 Tr 423.

Second, MEC/NRDC contended that, according to Consumers, there are no favorable wind PPA contracts in Michigan and, therefore, the contracts are not worth pursuing. MEC/NRDC disagreed, stating that:

> [t]he 2023 passage of both [Act] 235 and [Public Act] 233 [of 2023 (Act 233), MCL 460.1221 *et seq*.] change [sic] would-be developers' perspective of the viability of new wind generation within Michigan. Through the enhanced RES [renewable energy standard] and new CES [clean energy standard] requirements in [Act] 235, the state has produced a clear demand signal for new renewable energy development. Developers will respond to this signal. Where the difficulty of getting siting approval for new wind generation may have once made Michigan wind development appear untenable to developers, [Act] 233's state siting pathway signals that some once unviable geographies may again be viable.

2 Tr 424-425. Thus, MEC/NRDC asserted that PPAs for wind energy in Michigan may be more available for Consumers.

Third, MEC/NRDC argued that Consumers should consider contracting for wind generation outside of MISO Zone 7. In MEC/NRDC's opinion, "[w]ind resource is very unevenly distributed geographically, and the total availability of low-cost, easily developable wind resource in MISO Zone 7 is low compared with the rest of MISO North and the overall need for wind generation to meet Michigan clean and renewable energy goals." 2 Tr 425. MEC/NRDC presented modeling data from the National Renewable Energy Laboratory's reV model showing an abundance of low-cost, developable wind resources outside MISO Zone 7. MEC/NRDC acknowledged that there are some cost risks with contracting for wind generation outside MISO Zone 7 but asserted that Consumers can manage the risks by evaluating the REP resource proposals "on the difference between levelized cost of energy and the expected basis differences of both energy and capacity in the resource location [versus] Consumers' service territory." 2 Tr 429-430.

Similar to MEC/NRDC, MEIU expressed concern that Consumers' proposal to own all 2,800 MW of wind resources "exposes ratepayers to a higher level of risk and the potential for increased cost while ignoring opportunities for third-party ownership of additional wind energy resources to support the Company's 2030 and 2035 REC compliance goals." 4 Tr 640. MEIU also asserted that following the enactment of Act 233, there has been an increase in third-party wind resource additions in Michigan that are likely to continue into the future. In addition, MEIU stated that "[t]he Company's proposal for 100% Company-ownership of the proposed wind resource additions is inconsistent with recent Commission orders that have regularly supported an approximately 50/50 split between Company-owned and third-party owned resources to fulfill utility capacity addition needs . . . ." 4 Tr 644. Furthermore, MEIU contended that Consumers' proposed ownership of all wind resources requires the company to bear all the risks of ownership: the cost of installations, operations and maintenance, tax, and capital, along with site-specific

challenges, scheduling delays, and labor issues. MEIU stated that, "[b]y contrast, PPAs between the Company and third parties are most often structured in a manner that mitigates overall risk exposure for ratepayers." 4 Tr 648.

MEIU contended that if the Commission approves Consumers' proposal:

> not only would it preclude customers from enjoying cost savings that third-parties could bring to this procurement, but it would also signal a significant policy shift compared to the ownership structure for prior resource procurements, chilling future third-party interest in the State and directing the wind energy market towards a level of utility ownership it has not experienced to date.

4 Tr 651. Additionally, MEIU asserted that the company's proposal prevents ratepayers from receiving the lowest-cost, most reasonable, and prudent resources. MEIU stated that the Commission should approve an explicit 50/50 ownership split and third-party-ownership of the proposed additions and requested that Consumers follow the same competitive bidding process as it does for the company's IRP resource additions, including the use of an independent administrator (IA).

The Attorney General argued for the continued use of a 50/50 ownership split. She explained that in prior Commission proceedings, parties asserted that third-party PPAs would provide lower costs for customers; these parties relied on the Commission's February 15, 2017 Report on the Implementation of the PA 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards, which found that the weighted average cost of PPAs were consistently lower than the cost of company-owned projects. The Attorney General stated that "[b]ecause of this, parties have argued for restrictions on future ownership of renewable energy by electric utilities in order to promote and preserve the competitive market for renewable energy in the State and as a way of ultimately reducing ratepayer costs." 2 Tr 460.

The Attorney General also noted that in Consumers' IRP approved by the June 23 order, "the Company agreed that future competitive solicitations would follow existing agreements restricting Company ownership to only 50 percent of future assets." 2 Tr 459. She stated that, in this case, Consumers is proposing approximately 50% of all future VGP and REP solicitations will be provided by PPAs from third parties and 50% will be owned by the company. The Attorney General recommended that "the Commission reiterate the Company's existing commitment that only 50 percent of renewable energy resources selected through future competitive solicitations be Company-owned. This restriction is intended to limit the involvement of rate-regulated entities in the development of renewable energy facilities in the State and thus provide benefits to ratepayers from healthy competition." 2 Tr 461.

In response to MEC/NRDC, Consumers stated that:

> [a]cceleration of the acquisition of wind generation resources is dependent on cost competitive and viable projects being available that are in relatively late stages of development. The availability of those projects is scarce as indicated by recent solicitations conducted by the Company. That said, the passage of the 2023 energy legislation, including the option of siting renewable energy projects through the [Commission], has encouraged new wind development in Michigan. These projects will take several years to advance through development. The Company believes that many of these projects will be able to achieve commercial operation in the early 2030's and has therefore reflected a large increase in wind acquisition in those years. Ultimately, the Company will continue to seek wind projects through the competitive solicitation process, including within and outside of MISO Zone 7, and will acquire wind resources (through Company ownership or power purchase agreements ("PPAs")) that are price competitive.

2 Tr 233. Consumers explained that it modeled all wind resources as owned by the company because, based on the results of recent VGP solicitations, this was the worst-case scenario for the incremental cost of compliance (ICOC). However, Consumers stated that "[t]o the extent that the Company can contract for economic wind assets, its incremental cost of compliance will be reduced, all other things being equal. It is still the Company's position that it will not own wind

resources outside of the state of Michigan." 2 Tr 85-86. The company also asserted that there are advantages to company-owned wind assets, such as terminal value (additional value that would accrue for an owned asset compared to no asset value following the expiration of the PPA), the ability to re-power, and the economies of scale associated with operation of multiple renewable energy resources with standard designs.

Consumers disagreed with MEIU's proposal that the company strictly adhere to a 50/50 split between company-owned wind projects and PPAs. The company noted that in the August 22 order, the Commission found that "requiring a concrete ratio might result in inferior projects being selected just to satisfy a predetermined ratio." 2 Tr 85 (quoting August 22 order, p. 11). However, Consumers did not object to MEIU's recommendation that the company use an IA to oversee the competitive procurement process.

Although the "Staff has supported a 50/50 requirement in the past . . . and believes that there is value to competition," the Staff contended that "the Commission should continue to encourage Consumers to include the option for third-party PPAs in each renewable energy and energy storage solicitation going forward, but does not believe that it is prudent to require the Company to maintain a 50/50 portfolio in doing so." 4 Tr 809. The Staff asserted that the company should be selecting the most economical, feasible, and prudent resources to meet its requirements regardless of whether the resources are owned by Consumers or a third party.

The ALJ agreed with MEC/NRDC and MEIU that Consumers' proposal to delay acquisition of wind resources until 2032 and 2035 is not prudent. He explained that "[t]he Company's response that new wind facilities in Michigan will likely not be operational until these years ignores the current availability of out-of-state wind resources, as pointed out by MEC-NRDC." PFD, p. 35. In addition, the ALJ found Consumers' claim unpersuasive that the company's pursuit

of competitively bid wind projects, in state or out of state, will result in RPS compliance. He recommended that:

> the Commission predicate its approval of the amended REP on Consumers agreement to accelerate and more evenly distribute its planned new wind development including by actively soliciting PPAs for wind generation outside MISO Zone 7. Further the Company should evaluate its RFPs on the difference between LCOE and the expected basis differences of both energy and capacity in the resource location vs Consumers' service territory and choose the most economical and valid projects that meet its requirements, as recommended by MEC-NRDC.

Id., p. 36.

Regarding the proposed 50/50 split of company-owned wind assets and PPAs, the ALJ noted that, when Act 295 was enacted in 2008, the RPS required 50% PPAs. He stated that Public Act 342 of 2016 (Act 342) repealed this requirement and, therefore, "renewables can be owned, in any proportion, by either the Company or by third-parties . . . ." *Id*. The ALJ asserted that the current proper determination is whether, on a case-by-case basis, the renewables set forth in the REP are the most reasonable, prudent, and economical, and have been informed by an RFP. He "acknowledge[d] that the Company's commitment to pursue 50% PPAs in the 2021 IRP included wind but [found] that the commitment preceded Act 235 and therefore it may no longer be reasonable considering the increased RPS targets that Consumers must meet." *Id*. The ALJ also agreed with the Staff that "that allowing third-parties to bid into and compete in RFPs coupled with the Company's continued adherence to the competitive procurement guidelines, as established in Case No[.] U-20852, should ensure cost-effective renewable procurement going forward." *Id*., p. 37. Furthermore, the ALJ recommended that the Commission adopt MEIU's proposal, with which Consumers agreed, that the company use an IA during the competitive bidding process.

Consumers does not disagree with the ALJ's recommendation that the company accelerate its planned wind development and actively solicit PPAs for wind generation outside MISO Zone 7. However, Consumers notes that the ALJ expressed doubt regarding the company's proposal and, therefore, Consumers provides additional clarification in its exceptions. The company states that:

> [w]hen moving forward with a wind project, Company witness Kenneth D. Johnston indicated that the Company would select the lowest cost resource. To the extent that a Company-owned project's Levelized Cost of Energy ("LCOE") was lower than that of a PPA + FCM (Financial Compensation Mechanism), the Company should choose the Company-owned project. Conversely, if the cost of a PPA + FCM was lower than that of a Company-owned project, the Company should select the PPA. This includes PPAs for resources outside of MISO Zone 7 - if these PPAs are more financially viable than Michigan renewable energy resources. Additionally, the Company is willing to accelerate its procurement of wind projects through competitive solicitations so long as the projects are cost competitive and viable wind projects are available in relatively late stages of development to allow for them to come online earlier than planned.

Consumers' exceptions, p. 7 (citing 2 Tr 60, 86, 233).

The Attorney General states that "[f]or the reasons identified in the Attorney General's briefing, she takes exception to the PFD's recommendation for an ownership standard other than the 50/50 standard agreed to by the Company in the U-21090 IRP settlement." Attorney General's exceptions, p. 5. She requests that the Commission reject the ALJ's recommendation on this issue.

MEIU excepts to the ALJ's finding that a strict 50/50 ownership split would be unreasonable. MEIU reiterates the arguments set forth in briefing and contends that simply allowing third parties to bid into and compete in RFPs is insufficient to encourage competition and ensure cost-effective renewable procurement. Accordingly, MEIU requests that the Commission "find that a reasonable and prudent renewable energy plan requires a 50/50 ownership split in addition to independently administered solicitations compliance with the guidelines adopted in Case No. U-20852 and to condition its approval of the Company's access to the *ex parte* approval process on achieving a 50/50 ownership split." MEIU's exceptions, p. 7.

In response to Consumers' claim that when selecting a wind project, it would select the lowest cost resource, MEIU asserts that the company's goal is worthy—in the abstract. MEIU states that "the preservation of a healthy and robust third-party competitive market—which provides alternatives to utility resource builds—is the *means* through which to ensure the *goal* that customers obtain 'the most economic value' from utility acquisitions in the aggregate and in the long run." MEIU's replies to exceptions, p. 3 (quoting Consumers' initial brief, p. 19) (emphasis in original).

Consumers reiterates the arguments set forth in testimony and briefing and restates that it "does not believe a strict 50/50 ownership split in selecting assets from its competitive solicitations is appropriate." Consumers' replies to exceptions, p. 8.

The Commission finds that the ALJ's recommendation should be adopted in part. The Commission agrees with the ALJ that it is not reasonable or prudent for Consumers to delay acquisition of 2,300 MW of wind resources until 2032 and 2035 because, as noted by MEC/NRDC, the delay may result in the company's inability to comply with the RPS. Therefore, the Commission directs Consumers to accelerate its acquisition of new wind resources, which may include actively soliciting PPAs for wind generation outside of MISO Zone 7.

The Commission agrees with the ALJ that Act 342 repealed the 50% PPA requirement for wind assets and that, pursuant to Act 235, "renewables can be owned, in any proportion, by either the Company or by third-parties . . . ." PFD, p. 36. However, the Commission agrees with the Staff that 100% company-ownership of wind resource assets is unreasonable because it precludes the benefits of healthy competition and cost-effectiveness. Therefore, the Commission adopts the ALJ's recommendation that Consumers be directed "to actively solicit third party PPAs in all its future RFPs, including those from outside Michigan, and to select the most feasible and

economical projects for customers regardless of ownership." *Id*., p. 37. Put simply, the company is obligated to select the projects that are in the best interests of its customers—whether those projects are directly developed by the company, developed by a third-party under a BTA, or developed by a third-party with the electricity purchased by the utility under a PPA. This requirement, rooted in fundamental concepts of reasonableness and prudence, requires the utilization of a robust and unbiased competitive procurement process. As such, the Commission also agrees with MEIU and Consumers that the company shall use the same competitive bidding processes that it currently does for its IRP resource additions, including the use of an IA, to procure additional wind resources.

Additionally, the Commission acknowledges MEIU's concern that simply providing an opportunity for third parties to bid into RFPs is not sufficient to encourage competition and to ensure the procurement of cost-effective renewables. Accordingly, the Commission intends to expedite the review and revision process of the competitive procurement guidelines approved on September 9, 2021 in Case No. U-20852. The scale of renewable resource additions, the accelerated need for these additions, and the availability of a more lucrative FCM necessitate initiating this review to ensure that resources are procured in a fair and competitive manner, as illustrated by MEIU and Staff testimony.

The Commission respectfully declines to adopt the ALJ's recommendation that Consumers should evaluate its RFPs on the difference between LCOE and the expected basis differences of both energy and capacity in the resource location compared to Consumers' service territory, as suggested by MEC/NRDC. *See*, PFD, p. 36. Pursuant to the Revised Integrated Resource Plan Filing Requirements approved on October 27, 2022, in Case No. U-18461 (October 27 order), a utility's IRP shall include "an implementation plan that specifies the major tasks, schedules, and

milestones necessary to implement the proposed resource plan over the implementation period," which shall contain, among other things, "[a] description of how, to the extent practical, the construction or investment in new resources in this state will be completed using a workforce composed of residents of this state . . . ." October 27 order, Attachment A, p. 24. Thus, the Commission finds that MEC/NRDC's proposal that the company evaluate RFPs using the difference between LCOE and the expected basis differences of both energy and capacity in the resource location compared to Consumers' service territory conflicts with the requirement in the IRP Filing Requirements that the company consider how the development or acquisition of new resources in this state "will be completed using a workforce composed of residents of this state . . . ." *Id*. Accordingly, the Commission finds that this recommendation should be rejected.

c. *Ex Parte* Approval and 140% Levelized Cost of Energy Multiplier

Consumers stated that its "modeling in this filing reflects a LCOE of $55.44/MWh for wind energy resource additions with a January 1, 2028 commercial operation date ('COD')" and an "LCOE of $70.31/MWh for solar energy resource additions with a January 1, 2028 COD." 2 Tr 60. Consumers requested that "the Commission allow the Company to receive ex parte approval for future projects for solar and wind renewable energy resources that have a LCOE which is up to 140% above the LCOEs targets" set forth above. 2 Tr 61. Consumers explained that the 140% multiplier is reasonable because it reflects risks such as developers failing to pass along tax credits, developers increasing prices in anticipation of repealed tax credits, the delay of the MISO interconnection queue, competitive solicitations priced at or below target LCOE, federal tariffs on solar panels, construction cost inflation, and increased land prices. The company stated that these risks "have resulted in fewer solar MWs at a competitive price" and, therefore, "a

threshold multiplier of 140% would allow the Company to efficiently implement its RE Plan." 2 Tr 61-62.

The Attorney General objected to Consumers' proposal, asserting that "[t]he Company proposes to shift development risks from developers onto ratepayers. Specifically, the Company's proposal has the possibility of adding an additional $373 million to the already significant cost of the proposed RE Plan. Ratepayers will also receive no benefits for shouldering these additional development risks." 2 Tr 447.

The Attorney General noted that the U.S. Energy Information Administration (EIA) prepares a LCOE analysis in support of its Annual Energy Outlook (AEO). She stated that the most recent LCOE analysis was conducted in April 2023, and it:

> concerned new generation units entering service in the year 2028 with an estimated 30-year cost recovery period. EIA estimates a LCOE for region 5 (covering the majority of the lower peninsula of Michigan) of $27.41 per MWh in 2022 dollars for new onshore wind generation under the 2023 AEO reference scenario. Likewise, EIA estimates a LCOE for region 5 solar photovoltaic [(PV)] generation of $26.87 per MWh in 2022 dollars under the 2023 reference scenario. Even when examining EIA estimates assuming the removal of tax credits under the Inflation Reduction Act, the LCOE for these technologies is significantly less than that estimated by the Company.

2 Tr 458-459 (footnotes omitted). She also recommended that the Commission remind Consumers that in the settlement agreement approved by the June 23 order, the company agreed that only 50% of renewable energy resources acquired through competitive solicitations will be company-owned.

In response to Consumers' claim that the 140% multiplier is necessary to accommodate the risks associated with developers, MEC/NRDC asserted that the company failed to quantify the risks or provide evidence as to how the risks impact prices. MEC/NRDC also noted that according to Consumers, "[a] review of the solar bids offered that would achieve the Company's solicitation targeted capacity (500 MW per year), reveals that the marginal bid is approximately $97/MWh (or

approximately 140%)," but that Consumers "never introduced that analysis into evidence and it does not appear in [their] workpapers. Nor has Consumers provided any rate impact or other analysis to demonstrate that acceptance [of] its proposal will not increase rates or charges." 2 Tr 406-407 (quoting 2 Tr 61). MEC/NRDC recommended that the Commission deny the company's request for *ex parte* approval of projects that are priced up to 140% of Consumers' LCOE. MEC/NRDC asserted that Consumers could still seek "approval of projects that are priced higher than 100% of the Company's projected LCOEs" in a contested case, such as an REP amendment, REP reconciliation, or a standalone proceeding. 2 Tr 407.

GLREA disagreed with Consumers' claim that there is a risk that developers may not pass along tax credits; rather, GLREA asserted that there is no risk if the bidding is actually competitive. Specifically, GLREA stated that "[i]f one developer didn't consider the tax credits in their pricing, but other bidders did include the effect of the tax credit in their pricing, the developer that didn't consider tax credits or planned on pocketing them would not win a contract." 4 Tr 560. In addition, GLREA argued that the risks associated with repealed tax credits, the MISO interconnection queue delay, tariffs on solar panels, inflated labor costs, and increased land prices are not new risks. GLREA stated that these risks "could be mitigated with terms and conditions in the contract . . . ." 4 Tr 562. Furthermore, GLREA asserted that Consumers failed to provide "evidence that developers are pricing in any particular risk; these suggestions regarding what developers may be considering or may consider in the future when setting their bid prices are purely speculative . . . ." 4 Tr 562.

GLREA also noted that in response to Consumers' December 8, 2022 IRP solicitation requesting 500 MW of solar, the company received 38 proposals that represented approximately 1,665 MW of capacity. In addition, GLREA stated that in response to Consumers' September 24,

2021 IRP solicitation requesting 500 MW of capacity, the company received 28 proposals representing 1,500 MW of capacity. GLREA contended that Consumers is receiving adequate bids, but that the issue is price. Although Consumers claims that the marginal bid is $97/MWh (or approximately 140%), GLREA asserted that "the Company's filing doesn't define what it means by 'the marginal bid' and provides no data on the bids received to support its assertion." 4 Tr 564.

GLREA noted that if the Commission does not approve the 140% multiplier and the company has insufficient bids below the modeled price, Consumers will need to seek cost recovery in a contested case, which will take longer than *ex parte* approval. However, GLREA asserted that this "is not an entirely bad outcome; developers will want the more expedited process, and may keep their bids lower to avoid a contested case. It would also allow intervenors other than staff to review the bids and issue discovery requests to ensure that the bidding process was truly competitive." 4 Tr 564; *see also*, 4 Tr 620.

In the event the Commission approves the 140% multiplier, GLREA argued that developers may bid high, knowing they can receive expedited approval without the review of intervenors in an attempt to acquire higher profits. GLREA stated that:

> [t]his is a low risk if a large number of unrelated bidders are bidding enough capacity, but the risk goes up the fewer bidders there are. The impact could be quite substantial. The Company projected the build cost at $27.8 billion, but if the average bid was just 20% higher than the Company's modeled price, it would increase the cost by (20% x 27.8 billion) = $5.56 billion.

4 Tr 564. Therefore, GLREA recommended that the Commission reject Consumers' proposed multiplier and, instead, approve 110.4% for solar and no multiplier for wind, which is based on data provided by LevelTen, a company that tracks renewable energy pricing.

GLREA contended that, to date, the Commission has not granted permission for *ex parte* approval for contracts that are substantially more expensive than the company's target price.

However, GLREA asserted that if the Commission grants Consumers' request for *ex parte* approval "for projects with a LCOE above the modeled cost by any amount, the Commission should limit the duration of that approval until the Commission's order in the Company's next REP case, where it can be reconsidered." 4 Tr 566.

MEIU stated that it supports the elements of Consumers' proposal that "could alleviate the administrative burden on the Commission, its Staff, the Company, and any third-party bidder under a potential PPA to facilitate timely approval of procurements." 4 Tr 655. However, MEIU contended that the company's proposal is incomplete "because it lacks sufficient elements and safeguards that would ensure a competitive and fair process." 4 Tr 655. If the Commission approves an *ex parte* approval process, MEIU recommended the following conditions:

- The use of a competitive bidding process overseen by an IA;
- A mandated 50/50 ownership split between the Company and third parties;
- A mid-size (1–5 MW) procurement carveout to comprise up to 10% of total new solar resources; and
- A process to periodically revisit the Company's LCOE targets for wind and solar energy resources.

4 Tr 656. MEIU asserted that if the Commission allows Consumers to acquire new renewable resources on an *ex parte* basis and without an IA, the Commission should direct the company to ensure, as reasonably as possible, that it maintains a 50/50 ownership split for new renewable resource procurements. MEIU argued that "[w]ithout such a requirement, given the Company's stated preference to own all new renewable resources, it is possible that any such unrestricted *ex parte* contract approval process may result in the procurement of more expensive, solely Company-owned resources." 4 Tr 656-657.

MEIU also asserted that an effective competitive procurement process must include an IA. According to MEIU, an "IA is important because it (1) oversees the procurement process, (2) conducts the evaluation and scoring of proposals, and (3) communicates its results to the utility

in an anonymous manner for a utility to choose the comprehensively best partner for resource procurement." 4 Tr 657. MEIU contended that the Commission should require the use of an IA for any renewable resources procured through an amended REP and any renewable resources procured beyond the amended REP.

Additionally, MEIU stated that "any Commission authorization for *ex parte* project review be conditioned upon a commitment to revisit the Company's proposed LCOE targets for wind and solar resources by the time of filing of the Company's next RE Plan." 4 Tr 660. MEIU explained that to ensure the development of cost-effective solicitations that are beneficial to the company and its ratepayers, the Commission should determine an accurate and economically viable LCOE for Consumers' next amended REP. Moreover, MEIU asserted that:

> the landscape for renewable energy development is dynamic and fast-changing. In order for the Company to best incorporate up-to-date market information into its wind and solar LCOEs targets, [MEIU] recommend[ed] that the Company be required to update the LCOE targets every two years, or at the filing of each subsequent RE Plan, to reflect the most recent market sentiments.

4 Tr 661-662.

In response to the Attorney General's claim that the company's proposal shifts development risks from developers to ratepayers, Consumers asserted that the "proposal is not intended to avoid the rigid due diligence that is performed as part of each and every solicitation and simply execute contracts at almost any cost. Rather it is intended to expedite the delivery of new renewable energy resources and the associated attainment of renewable energy credit compliance pursuant to Act 235." 2 Tr 100. Consumers contended that the intention is not "to execute every new contract at 140% of the threshold baseline LCOE;" instead, the purpose "is to provide flexibility in the regulatory approval process so as to not further exacerbate the already slow onboarding of new renewable energy resources." 2 Tr 101. The company stated that it is mindful of the affordability

impact of the amended REP on customers and, accordingly, designed its amended REP in a manner that balances the potential impacts by not imposing a revenue recovery mechanism.

Consumers also disagreed with the Attorney General that the company's baseline LCOE estimates are already higher than expected. The company stated that:

> solicitations are run by an independent administrator and the Company has not received any proposals which are in the vicinity of the LCOEs discussed by [the Attorney General], and the results of its solicitations are consistent with its projected LCOEs. [The Attorney General]'s reference point is Energy Information Administration ("EIA") Region 5 which covers Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin. And while some of the available capacity factors for these states are similar, the siting availability, underlying construction costs, and interconnection requirements may vary.

2 Tr 101.

Furthermore, Consumers disputed MEC/NRDC's and GLREA's claims that the company failed to support the 140% threshold. Consumers asserted that it provided discovery responses, workpapers, and exhibits demonstrating that for "solar energy resource additions, . . . removal of the tax credits results in a 37% increase in the LCOE," and for "wind energy resource additions, . . . removal of the tax credits results in a 48% increase in the LCOE." 2 Tr 98. In addition, the company stated that "Confidential Exhibit A-46 (KDJ-6) presents and ranks the results of the Company's 2023 IRP solicitation based upon the solicitation criteria. This exhibit highlights the projects which would need to be selected to achieve the 500 MW target of the solicitation. The marginal project required to achieve the 500 MW target of the solicitation came in at a threshold multiplier of 139%." 2 Tr 98. Consumers contended that if the Commission rejects the company's proposed threshold, Consumers would need to request approval of renewable energy projects in a contested case, which may result in the company's inability to timely implement the projects and comply with the RPS.

Consumers also argued that MEC/NRDC's recommendation that the Commission reject the company's 140% threshold conflicts with MEC/NRDC's other suggestions. Specifically, the company stated that MEC/NRDC "proposes to revise the transfer price calculation which would allow for an increase in the amount of cost transferred to the PSCR. This proposal appears to request an increase in the level of costs transferred to the PSCR, an issue that is being argued against in the proposed rejection of the 140% threshold." 2 Tr 99. Additionally, Consumers noted that MEC/NRDC requests that the company accelerate its buildout of wind resources. However, the company asserted that MEC/NRDC's recommendation that the Commission reject the 140% threshold would result in the opposite outcome: "it could decelerate the Company's buildout of wind energy renewable energy resources due to the need to conduct a contested case prior to being able to move forward with project construction." 2 Tr 99. Consumers also disagreed with MEC/NRDC's recommendations that the Commission disallow REC-only contracts and modify the incentive REC criteria pertaining to peak time. The company asserted that these recommendations would effectively prevent Consumers from complying with the RPS.

Next, Consumers disagreed with GLREA that the company's LCOE calculations for wind and solar resources are inaccurate. The company argued that its "LCOE models were well founded and reflect current reality, that tax credits are still available, and tariffs have not significantly impacted the cost of renewable energy equipment." 2 Tr 105. However, Consumers agreed with GLREA that the authorization for *ex parte* approval should only extend to the company's next amended REP case.

In response to MEIU's recommendation regarding an IA, the company noted that it "currently utilizes IAs as part of its competitive procurement processes and has no intention of altering this practice." 2 Tr 363. Additionally, Consumers responded to MEIU's request that the company

regularly update the LCOE targets for wind and solar energy resources by stating that it plans to do this "in each of its subsequent Renewable Energy Plan amendments." 2 Tr 365. However, for the reasons set forth in the Company-Owned Wind Energy Resources section above, Consumers objected to a mandated 50/50 ownership split between the company and third parties.

The Staff found the intervenors' concerns regarding *ex parte* approval of up to 140% of the LCOE to be unpersuasive and, instead, supported the company's proposal. The Staff stated that:

> [t]he Commission has provided *ex parte* review and approval of both PPA and Company-owned renewable energy contracts since the first REPs were approved in 2009, subject to [Act] 295 of 2008. This provided expedited treatment of submitted contract approval request applications (~90 days as opposed to more than a year), which sent a signal to renewable developers within Michigan that there was little to no regulatory risk of projects being tied up in litigation for a year or more, costing time and ultimately money from these delays (such as interest on loans, lease payments, and litigation expenses).

4 Tr 811. If the Commission were to deny Consumers' request for *ex parte* approval and require contested cases instead, the Staff contended that developers may believe that project approval will be prolonged by litigation and developers are likely to include a risk premium in future bids—if they bid at all. The Staff also contended that requiring a contested case proceeding:

> would most likely increase the cost of Company-owned projects as well, through interest on regulatory balances, lease payments, and inflation, during litigation as companies front significant costs for projects well in advance of asking for Commission approval, but also may not procure necessary items (i.e., panels, racking, transformers, turbine blades, towers, etc.) that are all subject to inflation or other world events, such as regional conflict and/or tariffs until approval has been given.

4 Tr 812.

Regarding Consumers' proposed LCOE threshold multiplier of 140%, the Staff stated the purpose is for planning only and the Staff does not view the 140% "as the actual costs projected at this point or a contingency allowance in the event of cost overruns for approved projects." 4 Tr 812-813. The Staff asserted that it reviews and evaluates the actual costs submitted by the

company in the contract review process. Specifically, the Staff contended that it "audits the RFP process, proposals submitted in response to the RFP, and Company scoring methodologies before making a recommendation on that contract to the Commission." 4 Tr 813. The Staff stated that although the LCOE threshold multiplier of 140% may seem rather high, "this differential could be quickly realized if current federal tax credits are revoked (approximately 30%) and/or tariffs on imported components are in place, which is not entirely unlikely given the current administrative climate." 4 Tr 813. However, the Staff asserted that if a PPA or company-owned project exceeded the 140% threshold multiplier, the cost increase would have to be approved in a new contested case before that PPA or company-owned project could be approved through a contract review request application. In any event, the Staff recommended that "for future plans, the upper cost limit in REPs be tied to the upper cost limits included in the Company's most recently approved IRP and vice versa." 4 Tr 813-814.

In its brief, GLREA noted that:

> [a]fter rebuttal testimony was filed in the instant case, the [U.S.] House [of Representatives] Ways and Means Committee revealed a bill that would quickly phase out the federal tax credits for solar and wind facilities. GLREA recommend[ed] that the Commission direct the Company to modify their solicitation process to address this risk, by asking bidders to supply a quote with two prices. The "standard price" on bids would assume the tax credits continue, at least long enough for that project to qualify for the tax credits. An additional "contingency price" should be included in future bids, which would take effect if, and only if, the applicable federal tax credits were repealed prior to the project qualifying for them.

GLREA's initial brief, pp. 6-7 (citing 3 Tr 590). GLREA asserted that if the Commission does not wish to include a federal tax credit repeal "contingency price," then the Commission approve the four process modifications recommended by MEIU, along with the *ex parte* cap at 140%.

According to the Attorney General, Consumers admitted that it did not model the financial impact of the 140% multiplier and the company "appears to have no calculations, analyses, or

other reasonable basis to believe that passing this 140% in administrative expenses on to customers could qualify for *ex parte* relief." Attorney General's initial brief, p. 25. And, in response to the company's claim that the Attorney General's reliance on the LCOEs in the EIA's AEO is misplaced, the Attorney General asserted that "EIA's AEO is a public forecast that the Commission has recognized as appropriate in the past as estimates of future natural gas prices within Integrated Resource Planning ("IRP") modeling." *Id*., p. 27 (citing the November 21, 2017 order in Case No. U-18418, p. 35).

MEC/NRDC noted that Consumers recently submitted seven projects for approval that are all significantly under the 140% multiplier threshold and that correspond with the estimate from the IRP. In MEC/NRDC's opinion, "Consumers' evidence for positing an increase in costs resulting from recent RFP responses must be weighed against the much lower costs realized in recent approved projects – with the latter given greater weight than Consumers' relatively thin evidence . . . ." MEC/NRDC's initial brief, p. 48. In addition, regarding Consumers' claim that the marginal project required to achieve the 500 MW target of the solicitation is at a threshold multiplier of 139%, MEC/NRDC asserted that the project referenced by the company is 5 MW, interconnected to Consumers' distribution system, and an atypical project. MEC/NRDC argued that "[b]ecause [the company's claim] is based on an atypical project from a single set of RFP results, the marginal bid from the 2023 IRP solicitation should not be given any weight . . . ." *Id*., p. 49.

MEC/NRDC also disputed Consumers' claim that without the 140% threshold multiplier, the company will have to seek approval in a prolonged contested case and, therefore, may not be able to timely comply with the RPS. MEC/NRDC asserted that "while that is theoretically possible, it has not been Consumers' experience in reality. [Consumers' witness] Mr. Johnston testified on

cross that the contested cases on solar contracts Consumers has submitted for approval in recent years have all settled – and in the only case that had an intervention, 'beyond the prehearing, the time wasn't extensive.'" *Id*., p. 50 (quoting 2 Tr 144).

The ALJ acknowledged the concerns expressed by the intervenors, however he found that Consumers supported its proposed 140% threshold multiplier and recommended Commission approval. He stated that "[a]s explained by Staff and Consumers, and generally noted by GLREA, the current energy landscape, particularly as to inflation and the availability of federal tax credits for wind and solar, is creating uncertainty and risk for developers" and, therefore, the company's proposed 140% threshold multiplier is necessary to mitigate those risks and allow Consumers to meet the RPS. PFD, pp. 51-52. The ALJ also found persuasive the Staff's assertions that the actual costs will be reviewed and evaluated by the Commission.

The ALJ disagreed with the Attorney General's and MEC/NRDC's claims that Consumers' proposed 140% threshold multiplier will increase costs for customers and, thus, *ex parte* approval is not appropriate. He found "that approving the 140% LCOE is not contrary to [MCL 460.6a(3)]." *Id*., p. 52. However, the ALJ found MEIU's recommendation persuasive "that ex parte approval be contingent upon the Company's use of an IA in its RFPs and that the wind and solar LCOE targets should be regularly updated, as the Company has agreed with both of these conditions." *Id*. Furthermore, he stated that if Consumers is actually soliciting third-party PPAs in its RFPs, then an explicit 50/50 ownership split is not necessary.

The Attorney General excepts, asserting that Consumers "failed to demonstrate how the 140% factor is a necessary cost adder or that passing on such costs as requested is reasonable and prudent." Attorney General's exceptions, p. 4. Accordingly, she requests that the Commission reject the ALJ's recommendation on this issue.

In exceptions, GLREA contends that the ALJ's recommendation that the Commission adopt the 140% LCOE threshold is not supported by evidence on the record. Specifically, GLREA asserts that "unsupported speculative fears that an extravagant threshold of LCOE plus 140% is necessary to limit project delays (by cutting off any rights to a potential contested case) is highly exaggerated and fallacious." GLREA's exceptions, p. 2. GLREA reiterates the arguments set forth in testimony and briefing, described above. *See*, *id*., pp. 3-6.

GLREA appreciates the ALJ's recommendation that any Commission approval of the company's request for *ex parte* approval of wind and solar contracts up to 140% LCOE be conditioned on the use of an IA and the company updating its LCOE targets every two years in an REP filing. However, GLREA argues "that those conditions should be adopted without approving an extravagant threshold of LCOE plus 140% as the demarcation between *ex parte* versus contested case project approvals." *Id*., p. 3. GLREA requests that the Commission reject Consumers' proposed 140% threshold and, in the alternative, adopt a LCOE plus 110% for solar, but no margin factor for wind projects.

In reply to the Attorney General's and GLREA's exceptions, Consumers asserts that "[t]hese exceptions fail to recognize that the Company developed the 140% LCOE threshold based on what would happen if the federal tax credits were eliminated." Consumers' replies to exceptions, p. 8. Additionally, the company reiterates the arguments set forth in testimony and briefing, responding to the Attorney General's and GLREA's concerns that the 140% LCOE threshold is expensive and risky for customers. *See*, *id*., pp. 8-10.

The Commission finds that the ALJ's recommendation should be adopted. As noted by the Staff, it is reasonable for Consumers to consider consequences to renewable resource development if the federal tax credits are revoked. Accordingly, Consumers provided workpapers showing that

removal of the tax credits increases the LCOEs for solar and wind energy resource additions. *See*, 2 Tr 98; Exhibits A-44 and A-45. The company also presented an exhibit that included the results of Consumers' 2023 IRP solicitation and that "highlight[ed] the projects which would need to be selected to achieve the 500 MW target of the solicitation . . . ." 2 Tr 98. Consumers asserted that the "marginal project required to achieve the 500 MW target of the solicitation came in at a threshold multiplier of 139%." 2 Tr 98. The Staff acknowledged that the company's proposed 140% threshold seems high, however the Staff stated that it allows a reasonable price range for projects in an uncertain administrative climate and helps ensure that the company can meet the RPS in the event there are unexpected cost increases for renewable energy. The Commission agrees. However, the Commission finds that the Staff's recommendation that "for future plans, the upper cost limit in REPs be tied to the upper cost limits included in the Company's most recently approved IRP and vice versa" should be approved. 4 Tr 813-814. Additionally, the Commission agrees with GLREA and Consumers that the Commission's authorization of the 140% threshold should only extend to the date of the order issued in the company's next amended REP and should be reviewed in that case. *See*, 2 Tr 105-106; 4 Tr 566.

The Commission agrees with the Staff and Consumers that approval of the 140% LCOE threshold is for planning purposes only and does not reflect a contingency allowance or the actual costs projected at this point in time. As noted by the Staff, "[a]ctual costs are reviewed and scrutinized through contract review request applications filed by the Company with the Commission, in which Staff audits the RFP process, proposals submitted in response to the RFP, and Company scoring methodologies before making a recommendation on that contract to the Commission." 4 Tr 813. In addition, as noted by Consumers, approval of the 140% threshold LCOE should not result in a situation in which every new contract is executed at 140% of the

threshold LCOE. Rather, the purpose of the proposal is to provide needed flexibility in an uncertain climate. The company is still required to perform due diligence to determine the economic prudence of a potential contract. Therefore, the Commission finds that the potential *ex parte* approval of projects for inclusion in Consumers' REP that are priced up to 140% of the company's projected LCOE does not increase costs for customers and may be approved pursuant to MCL 460.6a(3).

The Commission also agrees with the ALJ's recommendation that approval of the company's *ex parte* request should be conditioned on Consumers' use of an IA in its RFPs. The company noted that it already uses an IA as part of its competitive procurement process and intends to continue the practice. 2 Tr 363. Furthermore, the Commission agrees with the ALJ, Consumers, and MEIU that the company's wind and solar LCOE targets should be regularly updated in Consumers' subsequent REP amendments. Finally, the Commission agrees with the ALJ that it is not necessary to order an explicit 50/50 ownership split. The Commission finds Consumers' testimony persuasive that it "competitively bids contracts under the RE Plan" and selects the lowest cost renewable energy resources. *See*, 2 Tr 82-85, 233. As discussed in the sections above, the Commission expects Consumers to explore and select the most economical, feasible, and prudent resources to meet its requirements regardless of ownership.

d. Transmission Studies

GLREA stated that "Consumers Energy needs to work with MISO to determine if transmission lines will support the proposed generation assets and . . . to provide the results of that investigation to provide capacity and location on the existing transmission lines as well as any MISO upgrades." 4 Tr 614.

Consumers disagreed, asserting that:

> [t]ransmission connected generation is required to be submitted to and studied by MISO through the MISO Generator Interconnection Process ("GIP"). Through the GIP, MISO determines the Interconnection Facilities and Transmission Network Upgrades required to support the proposed generation asset at the requested level of interconnection service. The GIP culminates in an executed Generator Interconnection Agreement ("GIA") which outlines the requirements and obligations for the proposed generation asset to interconnect to the Transmission System including the upgrades necessary to facilitate the interconnection. The Company actively works with MISO through the MISO GIP.

2 Tr 230.

The ALJ "agree[d] with Consumers that the Company already works with MISO through the GIP to ensure that proposed generation can be supported or whether upgrades are needed." PFD, p. 53. Therefore, he recommended that the Commission reject GLREA's suggestion.

No exceptions were filed on this issue.

The Commission finds that the ALJ's recommendation is reasonable and prudent and should be adopted.

e. Renewable Resource Acceleration

GLREA contended that to mitigate the risks associated with the timely completion of sufficient generation resources to comply with the RPS, Consumers should "[f]ront load the build plan with more capacity earlier in the schedule. This will slightly increase the cost (due to the time-value of money), but will allow for some schedule slippage." 4 Tr 577. GLREA noted that Consumers' current REP build plan was included in the proposed course of action (PCA) in the settlement agreement approved by the June 23 order. GLREA stated that "[t]he PCA called for adding 500 MW of solar in every year from 2027 - 2040. A front-loaded build plan would acquire more capacity in earlier years and less in later years." 4 Tr 578 (citing Exhibit A-19 in Case No. U-21090). MEC/NRDC also asserted that the Commission should direct Consumers to

accelerate the procurement of new renewables, specifically wind resources. *See*, MEC/NRDC's initial brief, pp. 8-10.

Consumers agreed that front-loading the schedule may help with REC compliance. However, the company asserted that one of its "recent solicitations has shown that it would be incredibly difficult to accomplish an acceleration without the 140% LCOE threshold. As previously mentioned, the Company is concerned about customer affordability and in no circumstances would it propose to go beyond the proposed 140% LCOE threshold." 2 Tr 107 (citing Confidential Exhibit A-46). In addition, Consumers contended that it is not limiting the capacity that it acquires from recent solicitations. The company stated that "[t]he only limitation is an ability to acquire sufficient projects which are economic." 2 Tr 108.

GLREA stated that it is "reassured by the Company's response, and note[d] that a project's schedule becomes less important by front-loading the plan with more capacity. [GLREA] recommend[ed] that the Commission's order in the instant case specifically signal the Commission's willingness to approve contracts for *more* than the Company's planned 500 MW per year, if they are cost-competitive." GLREA's initial brief, p. 11 (emphasis in original).

The ALJ found that "the Company indeed appears to be willing and able to exceed the 500 MW per year projection for resource acquisition, provided the projects are economical. As such, the PFD does not find it necessary for the Commission to order Consumers to adjust its current practice." PFD, p. 55.

No exceptions were filed on this issue.

The Commission finds that the ALJ's recommendation is reasonable and prudent and should be adopted. The Commission notes that the company's proposed 140% LCOE threshold was approved, as discussed in the section above. The Commission expects approval of the 140%

LCOE threshold to assist in the accelerated procurement of new renewables, as noted by Consumers.

3. Sales Forecast

Consumers presented its electric retail sales forecast for 2024-2045, which includes bundled sales to residential, commercial, industrial, streetlighting, and inter-departmental classes, and excludes wholesale, intersystem, and choice sales. The company forecasted 3,792,124 MWh in sales to Industrial Large Economic Development (LED) customers in 2028, which increases to 8,667,407 MWh in 2045. *See*, Exhibit A-6. Consumers stated that "[t]he rapid advancement of artificial intelligence ('AI') and the need for large data centers to support this technology has had an impact on the Company's delivery forecast as reflected in the delivery forecast . . . ." 2 Tr 46. In addition, Consumers asserted that its sales forecast was used to project REC targets for 2023 through 2045. *See*, Exhibit A-33.

Regarding the participation growth for Rate LED, the Attorney General:

> [r]ecommend[ed] the Commission remove the increased REC requirement associated with incremental growth in the Company's LED rate after the year 2028. Growth in AI and the associated energy needs to support new data centers is a topic that many electric utilities throughout the country are currently addressing. Doubtless some of this growth will also occur in the Company's service territory. However, it is premature at the current time to include these loads when the Company cannot clarify how much of its additional load growth is associated with publicly announced projects versus private inquiries that are subject to change or outright cancellation. Section 22(3) of Act [235] requires that electric utilities file amended RE Plans with the Commission every two years, so these load additions can be included in future filings as the projects enter the public record.

2 Tr 471. Regarding the company's near-term forecasted additional LED electric sales, the Attorney General noted that Consumers filed a supplemental discovery response demonstrating that the sales are only associated with customers who have signed contracts with the company.

Accordingly, the Attorney General supported the company's near-term forecasted LED electric sales.

The CEOs opined that "[t]he biggest risk is that load growth will outpace renewable generation growth. In the initial years of the REP[,] the Company is well-positioned to address this risk . . . ," however, "the uncertainty around such forecasts . . . means that it is critical to develop robust and early planning which addresses a range of scenarios." 4 Tr 700-701. In addition, the CEOs asserted that Consumers' projected overall annual growth rate average of 4% for 2024-2031 seems relatively high. The CEOs stated that the National Renewable Laboratory's "2023 Standard Scenarios report, which provides a nationwide outlook for the U.S. electric sector, includes three different demand growth scenarios, ranging from 0.9% annually in the 'Low Demand Growth' scenario up to 2.8% in the 'High Demand Growth' scenario." 4 Tr 701. Furthermore, the CEOs noted that:

> [m]ore specific to the Midwest, MISO's most recent load forecast, published in December 2024, notes that peak demand is forecast[ed] to grow by 1 to 2% per year. However, in a presentation made in the same month, MISO indicated that growth rates up to 3.3% may also be possible, noting that current projections represent a three-fold increase over previous projections; this growth is attributed to an estimated 19 to 30 GW [gigawatts] of new data center load by 2040. Indeed, industry expert Grid Strategies noted in a December 2024 report that MISO's projections have increased steadily from 2022 through 2024.

4 Tr 701 (footnotes omitted). To mitigate the risks associated with increased load growth and possible failure to meet the RPS, the CEOs recommended that the company "develop a range of forecast scenarios, utilizing both their own information (as the projections in the REP seem to do) while also considering industry-wide forecasts. By utilizing a range of scenarios, the Company can be prepared to pivot quickly as new data becomes available over time to confirm which scenario is most likely." 4 Tr 703. The CEOs also requested that the Commission direct Consumers to model curtailment of renewables, including off-peak renewables production, on the

final PCA and any additional sensitivities that represent full decarbonization and/or high renewable penetration in the company's next IRP.

The CEOs also noted that the Attorney General may be correct to question the company's proposed load growth for Rate LED beyond 2028. The CEOs stated that "[i]f Consumers only plans for this future load growth based on the two year cycle of the REP process, there is significant risk that as load materializes the Company will not be able to meet its RPS obligations." 4 Tr 713.

In response to the Attorney General's claim that it is premature to include the load associated with data centers in Rate LED, Consumers stated that it "prepared its delivery forecast based upon the best information that it had available at the time of filing this amended RE Plan. To arbitrarily reduce the delivery forecast and assume that it can simply be added in the next amended RE Plan is negligent." 2 Tr 93. The company asserted that pursuant to Act 235, Consumers must comply with a significant increase in REC targets for 2030; if the company does not plan accordingly, it will likely be unable to comply. In addition, Consumers is not concerned that there will be an overbuild of renewable energy resources; rather, the company is more concerned about complying with the RPS in light of the potential risks with renewable energy resource asset growth. Consumers contended that "[m]uch of the Company's amended RE Plan is premised on its IRP glidepath for the addition of 8,000 MW of solar energy resources. The proposed glidepath for the addition of wind energy resources provides a significant amount of flexibility should the projected deliveries not materialize." 2 Tr 93-94.

Regarding the CEOs' claim that the company should develop a range of forecast scenarios, Consumers did not disagree but stated that an REP is not the proper venue to evaluate and establish IRP modeling requirements. The company contended that "[t]hose proposals can be

addressed in various activities pursuant to Case No. U-21570 and/or through the Company's planned IRP stakeholder outreach." 2 Tr 97. Consumers agreed with the CEOs that it should model curtailment in the company's next IRP. *See*, Consumers' initial brief, p. 48.

The Staff "agree[d] that curtailment is an issue that should be modeled and considered by the Company, but [the Staff] believe[s] that the IRP is the appropriate venue to conduct this planning." 4 Tr 817.

In briefing, the Attorney General withdrew her recommendation to remove longer-term REC projections and, instead, suggested that the Commission adopt the CEOs' recommendation to develop a range of load growth scenarios that address the anticipated load demand from data centers. She stated that "[a]s recommended by [the CEOs], these scenarios should include both Consumers' own data and a survey of publicly available data, MISO reporting, announced data center projects, and other reporting from relevant authorities." Attorney General's initial brief, p. 43. The Attorney General requested that the Commission require Consumers "to file a more robust analysis as part of its 2026 IRP plan application." *Id*., p. 44. Furthermore, she supported the CEOs' recommendation that the company be directed to provide additional modeling for curtailment of renewables and storage planning in Consumers' next IRP.

The CEOs objected to Consumers' claim that an REP is not the proper venue to establish IRP requirements. In the CEOs' opinion:

> [t]he Company provides no legal support for this position. The Company cites no caselaw or statute that limits the Commission's authority. There is no reason that the Planning Parameters docket must be the exclusive means to order analyses to take place in the IRP. Relatedly, if the Commission chooses to do so, it may implement the CEO's recommendations within the planning parameters docket for all Michigan utilities.

CEOs' reply brief, p. 2.

The ALJ agreed with the CEOs that "the Commission has the authority to direct the Company to model various load forecasts as part of this REP proceeding. However, contrary to the CEO's claim, Consumers never asserted that the Commission did not have such authority, only that it would be more reasonable to address modeling requirements in another forum, namely the Company's next IRP." PFD, p. 59. The ALJ also noted that the company generally agrees with the CEOs that there is a need for various load growth scenarios. He found that Consumers' "sales forecast presented here is reasonable; it complies with the requirements of Act 295, and the forecast can be adjusted over time in IRP and biennial REP filings." *Id*. Furthermore, the ALJ recommended that the requirements for load growth scenarios should be established in the IRP Filing Requirements in Case No. U-21570 so that requirements are applicable to all regulated utilities.

The Attorney General excepts to the ALJ's recommendation that the requirements for load growth scenarios should be deferred to Consumers' next IRP case, stating that her concerns have heightened during the pendency of this case. She explains that, in this case, Consumers omitted large data customers from the REP forecasts and, "recently on July 31, 2025, the Company announced that it had 'reached an agreement with a new data center, which is expected to add up to 1 gigawatt of load growth in [its] service territory.'" Attorney General's exceptions, p. 8 (quoting Exhibit MEC-46, p. 1, in Case No. U-21859). In light of this development, the Attorney General requests that the Commission direct Consumers to proactively model growth scenarios for the increased demand attributable to this type of customer in the company's next IRP.

The Attorney General also notes that it is unclear whether the ALJ specifically addressed the Attorney General's and the CEOs' recommendations that Consumers conduct curtailment modeling in its next IRP that is separate from the large load demand scenario modeling. She states

that "[t]o the extent the PFD intends a parallel finding on curtailment modelling as it finds for large load demand modelling, the Attorney General asks that the Commission reverse the PFD on that point as well." Attorney General's exceptions, p. 9.

In exceptions, the CEOs request that the Commission reject the ALJ's recommendation and direct Consumers to model various load forecasts as part of this REP proceeding. According to the CEOs, the ALJ "argu[ed] that the REP should not create IRP obligations for the Company. This approach elevates form over substance. The Commission should see past this argument and implement the best possible IRP modeling requirements, no matter the forum from which they spring. The CEO's recommendations derived from the development of a record in this case." CEOs' exceptions, p. 2.

The CEOs assert that they are not requesting that Consumers rework its REP to include the additional modeling scenarios. Rather, the CEOs recommend that the company run the various load growth scenarios in Consumers' next relevant proceeding—the company's IRP. The CEOs state that, "[a]lternatively, given that the Commission has yet to release the final IRP planning parameters and modeling requirements in U-21570, it could adopt these recommendations there for all Michigan utilities." *Id*.

The CEOs also contend that the ALJ did not address the CEOs' recommendations regarding the risk of curtailment or energy storage. The CEOs state that:

> [a]gain, the dispute around the adoption of these modeling requirements tracks the discussion above. While the Company agrees these would be sensible steps to take in an IRP, the Company protests that the REP is not the right venue to adopt IRP modeling requirements. As stated above, the CEO do not believe that should stand in the way of the best and most accurate possible modeling outcomes in the IRP.

Id., p. 3.

In reply, Consumers reiterates that it agrees that it should evaluate various load growth scenarios in an IRP, including storage and curtailment. However, the company restates that "particular IRP modeling requirements should not be established as part of this Amended RE Plan proceeding." Consumers' replies to exceptions, p. 11. Rather, Consumers asserts that IRP modeling requirements should be addressed in a separate proceeding opened for that purpose.

Consumers objects to the Attorney General's request that the company perform a curtailment analysis similar to the analysis included in the settlement agreement approved by the May 15 order. The company asserts that it "was not a party to the settlement agreement in Case No. U-21662 . . . and DTE Electric's agreement to perform any particular analysis in its next IRP as part of the resolution of Case No. U-21662 has no bearing on this case and is not binding on Consumers Energy." *Id*.

Finally, Consumers notes that the Attorney General's exceptions rely on a discovery response that was admitted as an exhibit in another case to demonstrate that the company's sales forecast fails to account for new load growth. The company asserts that "[i]t would be improper for the Commission to rely on testimony and exhibits from a different case, that are not part of the record here, to support its decision in this Amended RE Plan." *Id*., p. 13. Accordingly, Consumers requests that the Commission reject the Attorney General's exception on this issue.

The Commission agrees with the ALJ that, in this case, Consumers' sales forecast was projected with the best available information at the time and finds that the sales forecast is reasonable and complies with the requirements of Act 295. However, the Commission finds that in the company's next IRP, Consumers should evaluate various load growth scenarios, including storage and curtailment, which will assist the company in responding to uncertainty in the

forecasts. The Commission will consider including similar requirements for other rate-regulated utilities in the Michigan Integrated Resource Planning Parameters in Case No. U-21570.

4. Transfer Price

Consumers explained that, pursuant to the requirements of Act 295, "transfer price schedules should be representative of what a Michigan electric provider would pay had it obtained the energy and capacity (the non-renewable market price component) through a long-term power purchase agreement for traditional fossil fuel electric generation." 2 Tr 338 (quoting the April 18, 2024 MPSC Staff Transfer Price Schedule, Case No. U-15800, filing #U-15800-0054, p. 2[2]). Consumers asserted that the transfer cost "is the total cost that the Company will transfer to power supply costs in accordance with MCL 460.1047(2)(b)(iv) associated with renewable generation obtained in accordance with MCL 460.1047." 2 Tr 332. The company also asserted that MCL 460.1047(2)(b)(iv) states that the renewable energy costs that are included in the PSCR plan shall be considered "a booked cost of purchased and net interchanged power transactions under section 6j of 1939 Public Act 3, MCL 460.6j." 2 Tr 332 (quoting MCL 460.1047(2)(b)(iv)). Consumers noted that the transfer price was first defined in the Temporary Order. The company proposed to continue the current transfer price and deferred accounting methods for company-owned assets through December 2045.

The company provided an explanation of the renewable energy resources that are recoverable through the transfer price in the company's amended REP:

> [t]his plan includes a total of 8,104 MW of solar projects which would be recoverable via the transfer price mechanism. Of that, 504 MW are solar projects already in the RE plan and 690 MW are due to the moving of 4 IRP assets into the RE plan. The remaining 6,910 MW are unnamed proxy solar projects, which

[2] The Staff's April 18, 2024 Transfer Price Schedule in Case No. U-15800 is unpaginated. Therefore, all citations reference the pages in natural order beginning with the first page of the report.

> includes 1,060 MW of unnamed proxy solar VGP projects. The additional 1,060 MW of proxy solar VGP projects combined with the existing 398 MW of named solar VGP projects and the 120 MW of named VGP wind projects brings the total VGP size to 1,578 MW.
>
> Additionally, this plan includes a total of 2,800 MW of unnamed proxy wind projects and 1,200 MW existing wind projects recoverable via the transfer price mechanism. Finally, this plan includes 20 MW of existing resources that are not wind or solar technologies which are recoverable via the transfer price mechanism.

2 Tr 328-329. The company also provided a detailed description of its proposed renewable energy generation through 2045 that is included in the transfer price. *See*, 2 Tr 332-335. Accordingly, Consumers stated that its projected transfer price for 2024-2045 is $72.67/MWh. 2 Tr 337.

The company asserted that it is important that the Commission preserve the current transfer price because:

> [w]hile the Company's modeling assumes that no costs from the Renewable Energy Program renewable energy resources will be transferred to the PSCR via the transfer price mechanism, the modeling does indicate that the original transfer price mechanism that was re-established in Case No. U-20483 needs to continue to remain in place to maintain a regulatory liability balance. Through the renewable energy cost reconciliation filings, the Company has previously committed to returning to limiting transfer price to the levelized cost of energy ("LCOE") for Company-owned facilities when the risk of dipping into a regulatory asset position is low. As a result of Michigan's Act 235, the Company is proposing to return to limiting transfer price to the LCOE for Company-owned facilities starting in 2034 and continuing for the remainder of the plan period. The modeling in this proceeding is based upon a return to that transfer price methodology beginning in 2034. The Company will continue to report on the status of the regulatory account balance in its annual renewable energy cost reconciliation proceedings.

2 Tr 337.

Consumers also requested that a simplified transfer price schedule replace the schedules approved by the Commission in Case Nos. U-15805 and U-16581 for the following assets: Beebe Renewable Energy, Fremont Community Digester, Harvest II Windfarm, Heritage Garden Windfarm I (wind energy), Heritage Garden Windfarm I (solar energy), Heritage Garden Stoney Corners Windfarm I (Phase 2), Heritage Garden Stoney Corners Windfarm I (Phase 3), Michigan

Wind 2, North American Natural Resources (Lennon), WM Renewable Energy (Northern Oaks), WM Renewable Energy (Pine Tree Acres), and EARP Solar Aggregate No. 5. In addition, the company proposed to assign Lake Winds Energy Park and Lake Winds Energy Park Repowered to their own unique transfer price schedule. According to the company, the new simplified transfer price schedules will:

> reduce the administrative burden, and reduce potential errors, associated with the existing Transfer Price schedules approved in Case Nos. U-15805 and U-16581. The existing schedules include a monthly on-peak rate, monthly off-peak rate, and monthly capacity rate. More recently, Staff proposed Transfer Price schedules do not include a capacity rate and include only a yearly total $/MWh rate. The Company is proposing to align the new Transfer Price schedule structure with that of Staff's schedules.

2 Tr 339.

Consumers explained that the two new transfer price schedules were developed using the following methodology:

> [t]he Company first modeled the total Transfer Cost of the units which would be assigned the new schedule and recorded the total forecasted Transfer Cost associated with those units using the existing Transfer Price schedules. The Company then modeled those same units using a proxy Transfer Price schedule which was structurally different from the existing schedule (structurally similar to Staff's proposed schedules – one rate for all energy delivered in a year, no capacity rate). The new (proxy) schedule was determined by, for each year, setting the Transfer Rate ($/MWh) for a given year such that the new forecasted total Transfer Cost associated with these units would be equal to (or nearly equal to) the total forecasted Transfer Cost associated with these units under the existing schedules. The value of the new single value (as opposed to on-peak/off-peak and capacity) for Transfer Rate ($/MWh) for a given year generally falls in between the former on-peak schedule rate and off-peak schedule rate but is not simply the average due to the pooled resource generation profile not producing during exactly 50% on-peak and 50% off-peak hours and the existing schedules inclusion of capacity-based transfer costs. To state simply, the newly proposed Transfer Price schedules are based on the existing Transfer Price schedules applicable to these units and is similar to a weighted average of the on-peak/off-peak and capacity transfer rates based on the resource pool's generation profile/capacity accreditation. The new Transfer Price schedules were created using the Transfer Price Forecast model such that there would be very little impact to the total Transfer Cost associated with these 14 units as seen in column (h) of Exhibit A-31 (ZSC-8).

2 Tr 339-340. Consumers contended that the purpose of the new transfer price schedules is to reduce the impact of the total cost transferred to the PSCR. According to the company, "for the period 2025 through the end of 2045, the newly proposed schedules result in an estimated net total decrease of $20 when comparing the forecasted total cost transferred to PSCR with the existing Transfer Price schedules," which is insignificant. 2 Tr 340-341.

However, Consumers stated that there are several factors that could affect how the new transfer price schedule performs compared to the existing transfer price schedule, including the on-peak/off-peak generation split. The company asserted that the new transfer price schedules were developed using the three-year historical average of generation during on-peak and off-peak hours. Consumers noted that "[a] divergence of the total transfer cost could occur if a unit significantly strays from its historical on-peak/off-peak energy production (including outages). Similarly, a significant change to the capacity credit (ZRCs) for these units in comparison to their three-year historic average could also create a divergence of the total transfer costs." 2 Tr 341. The company contended that these plants must be assigned to the new transfer price schedules, rather than the Staff's transfer price schedule, because it is important to utilize schedules that were developed in a relatively similar timeframe to when these plants were constructed or included in the REP.

MEC/NRDC objected to Consumers' proposed transfer price schedules, asserting that this issue should be addressed in the company's REP reconciliation case. In any event, MEC/NRDC asserted that the Staff's transfer price method is not the appropriate method for projecting transfer prices. MEC/NRDC noted that:

> in Section 51 of 2023 PA 235[,] the State of Michigan adopted Clean Energy Standards requiring that in 2035 through 2039 an electricity provider must provide 80% of its sales from a clean energy resource and that in 2040 and thereafter an electricity provider must provide 100% of its sales from a clean energy resource. A combined cycle gas plant can be considered a clean energy resource but only if it

> "uses carbon capture and storage [(CCS)] that is at least 90% effective in capturing and permanently storing carbon dioxide. If the department of environment, Great Lakes, and energy determines through a facility-specific major source permitting analysis consistent with applicable United States Environmental Protection Agency [(EPA)] rules, that a capture rate higher than 90% meets the best available control technology standard, as applicable that higher percentage shall be used instead of 90% for facilities permitted after the effective date of the amendatory act that added section 51."

2 Tr 402-403 (quoting MCL 460.1003(*i*)(ii)). In addition, MEC/NRDC contended that the EPA's "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," 40 CFR 60, requires that new combined-cycle gas plants with annual capacity factors greater than 40% must operate with 90% effective carbon capture, which is to be installed and effective by January 1, 2032. MEC/NRDC opined that, because of the EPA rule, "it would not be prudent for a Michigan utility to construct a new combined cycle gas plant without carbon capture and storage. Since the transfer price is based on the levelized cost of a new combined cycle gas plant, the transfer price must account for the cost of carbon capture and storage." 2 Tr 403.

MEC/NRDC also recommended that the Commission approve an incremental addition to the transfer prices proposed by Consumers that is equal to the cost estimated by the EPA in 2019 dollars, adjusted for inflation. Specifically, MEC/NRDC stated that "[t]he transfer price method developed by Staff is based on a 400 MW capacity combined cycle plant. The [EPA] calculations most closely resembling the basis for the [Commission] Staff method is a 700 MW F-Class turbine, for which the [EPA] estimates a carbon capture and storage cost of $19/MWh in 2019 dollars," which should be increased by 19.3% to account for inflation for a total of $22.66/MWh. 2 Tr 404. Furthermore, MEC/NRDC recommended that the Staff develop a modified method for

determining the transfer price that incorporates CCS. MEC/NRDC asserted that its proposed transfer price "will substantially reduce the incremental cost of compliance" and "lead to lower regulatory asset or higher regulatory liability balances." 2 Tr 405. MEC/NRDC requested that the Commission direct Consumers to include in its next REP amendment a modified transfer price that includes the costs of CCS.

GLREA contended that it is not reasonable to retain the transfer price methodology that was developed in 2008 in Case No. U-15800. In GLREA's opinion, the 2008 transfer price methodology may have encouraged renewable energy development at that time, but is no longer pertinent now that renewable energy generation is the lowest cost generation technology. GLREA asserted that "[t]he transfer price of a generation asset should only cover the actual cost of construction of the generation," while for PPAs, "the company should pay for the cost of energy negotiated plus the cost/value of the RECs or more simply competitively bid for renewable energy assets with RECs included." 4 Tr 617-618. In the alternative, GLREA stated that the company's REP and IRP could be used to develop plans and, in the short term, to propose ready-to-build projects wherein the Commission could supervise the bidding process and evaluate construction cost recovery in a rate case.

ABATE objected to Consumers' new transfer price schedules proposed to replace the schedules approved in Case Nos. U-15805 and U-16581. ABATE stated that its:

> understanding is that the Transfer Price is used to classify renewable resource costs between demand and energy when those costs are reflected in the PSCR in a base rate case. If the Company recalculates the Transfer Price schedules that were approved in Case Nos. U-15805 and U-16581 to eliminate the capacity component, it is unclear how the Company would maintain the appropriate classification of costs for the assets to which the new Transfer Price schedules would be applicable, when those costs are reflected in the PSCR in a base rate case.
>
> Given that the costs of renewable resources are largely fixed costs and those resources contribute toward meeting the Company's capacity needs, it would be

> entirely inappropriate to cease classifying a portion of these costs as demand-related when they are reflected in the PSCR in a base rate case. The demand-related portion of costs should, at a minimum, be equal to the capacity-related portion of the Transfer Price schedules approved in Case Nos. U-15805 and U-16581.

4 Tr 727. ABATE also expressed concern regarding how Consumers' new transfer price schedules perform compared to the existing transfer price schedules. Specifically, ABATE stated that the company's new transfer price schedule may have "a divergence from the three-year average on-peak/off-peak generation split, or changes to the capacity credit (Zonal Resource Credits) in comparison to their three-year historic average," and that it is unknown whether these variances could occur during the REP. 4 Tr 728 (citing 2 Tr 340).

Additionally, ABATE opposed MEC/NRDC's request that the Commission adopt a transfer price schedule that is based on a new combined-cycle gas plant with CCS. ABATE stated that:

> MEC-NRDC's proposal would add $22.66/MWh to the existing transfer price. For reference, compared to the Company's forecasted transfer price of $72.67/MWh for the RE Plan period, an adder of $22.66/MWh would represent a 31% increase, although it's important to note that this could further increase over time as updated and localized CCS cost estimates are incorporated in future cases.

ABATE's initial brief, p. 3 (citing 2 Tr 360-362, 401-406; 4 Tr 736-741, 804-808).

ABATE noted that, after technical conferences were conducted in Case No. U-15800 and after much deliberation, the Staff found that the levelized cost of a new combined-cycle gas plant is analogous to the market price for a long-term PPA for traditional fossil fuel electric generation and, therefore, the most appropriate proxy for developing the transfer price schedule. ABATE asserted that, "[c]ontrary to this deliberative process and determination, and rather than comprehensively reevaluate the transfer price method based on the factors set forth in MCL 460.1047(2)(b)(iv), or whether an alternative proxy may be appropriate, the MEC-NRDC proposal here would simply add additional costs to this NGCC [natural gas combined-cycle] plant

proxy price." ABATE's initial brief, p. 5. In ABATE's opinion, it is unreasonable and premature to adopt MEC/NRDC's proposal and, instead, ABATE recommended that the Commission direct the Staff to host a deliberative workgroup to resolve this issue.

Consumers also disagreed with MEC/NRDC's proposal, stating that it does not align with the Commission's current transfer price schedule methodology. Similar to ABATE, the company contended that this issue should be addressed by a workgroup and "not in a standalone case for a single utility." 2 Tr 362.

The Staff agreed with Consumers that the original transfer price mechanism that was re-established in Case No. U-20483 should remain in place but noted that transfer prices are adjusted and approved in annual reconciliations. The Staff also supported the company's proposal to modify the transfer price schedule that was approved in Case Nos. U-15805 and U-16581. In the Staff's opinion, "this modification, as proposed by Company witness Cole, is a much simpler and transparent transfer price schedule than the Company's existing transfer price schedule that is applied to Lake Winds Energy Park." 4 Tr 797.

In response to MEC/NRDC's recommendation that the transfer price methodology be based on a new combined-cycle gas plant with CCS, the Staff stated that it would not object to the current methodology being reviewed or reevaluated. However, the Staff disagreed with MEC/NRDC that the "Staff's current methodology is flawed in light of current events." 4 Tr 804. The Staff asserted that the use of a new combined-cycle gas plant as a proxy to determine the current transfer price schedule is not inconsistent with the requirements of Act 235, which directs electric providers to meet the clean energy standards of 80% beginning in 2035 and increasing to 100% in 2040. Specifically, the Staff explained that its:

> transfer price methodology is representative of what a Michigan electric provider would pay if it were to obtain energy and capacity from the market through long

> term power purchase agreements (PPA). It is assumed that the PPA prices would converge towards the market pricing set by an NGCC. Currently, the transfer price schedule is updated annually by Staff, filed in Case No. U-15800, and then utilized by several rate-regulated electric providers, including Consumers Energy Company (Consumers or the Company), to develop renewable cost reconciliation filings and renewable energy plans (REP). All but one of the Michigan rate-regulated utilities are Midcontinent Independent System Operator (MISO) market participants. MISO includes fifteen states and operates in the Canadian province of Manitoba, jurisdictions which are clearly not subject to Michigan clean energy laws and policies. While there is a locational component to the MISO market pricing through congestion for Locational Marginal Pricing and Local Clearing Requirement for capacity, the energy and capacity market is not clearly defined by state borders or state policies. It would be hard to absolutely define what impact Michigan's clean energy laws will have on future energy and capacity prices through all of MISO and if future PPAs will converge towards the price of a NGCC with carbon sequestration or remain close to that of a traditional NGCC.

4 Tr 804-805 (footnote omitted). The Staff also stated that new combined-cycle gas plants could be built in Michigan if the utility offsets the generation with an equal amount of clean energy system generation. However, the Staff acknowledged that due to the requirements set forth in Section 111(b) of the federal Clean Air Act, 40 CFR 60, and Act 235, the future of natural gas plants in Michigan is somewhat uncertain. Accordingly, the Staff asserted that "[d]ue to the uncertainty around the future of natural gas generation and what impact these changes may have on market pricing, it is premature to make changes to the transfer price proxy, as proposed by MEC-NRDC . . . ." 4 Tr 806.

Furthermore, the Staff argued that increasing the transfer price, as requested by MEC/NRDC, would not impact the method for cost recovery of renewable energy for PPAs but would affect company-owned facilities. The Staff explained that Section 47(2)(b)(iv) of Act 235, MCL 460.1047(2)(b)(iv), states that the company shall recover the cost of a PPA or the transfer price, whichever is lower, through the PSCR mechanism. The Staff asserted that:

> Company-owned facilities are not subject to this "lesser than" restriction. For a Company-owned facility, if required to recover a transfer price that adds costs associated with carbon capture as proposed by MEC-NRDC witness Jester, it would

> result in a significant increase in the amount of cost recovered through the PSCR, which would greatly reduce the balance associated with the incremental cost of compliance (regulatory asset/liability). Since the Company is not currently requesting a surcharge for the incremental cost of compliance, there is no need to contemplate an increase in the costs recovered through the PSCR at this time.

4 Tr 806. The Staff contended that other methodologies could be considered for establishing a transfer price proxy, such as solar generation, but maintained that the Staff's current methodology is still a valid option. The Staff asserted that if the Commission would like to reevaluate the current transfer price methodology, the Staff recommended that the Commission direct the "Staff to convene a workgroup, including all rate-regulated utilities and interested parties, with the objective to review and potentially reevaluate the existing Staff transfer price methodology to determine if/how it should be updated, as there are many potential options that could be appropriate outside of the existing methodology or that proposed by MEC-NRDC." 4 Tr 807-808.

Next, the Staff disagreed with ABATE's claim that if the current transfer price methodology is changed, the proportion of demand-related costs should be maintained. The Staff stated that its: "preference would be that the determination of the transfer price by capacity and energy portions in the same manner as was previously done be maintained. To the extent it is not, the proportional split of the transfer price between capacity and energy should be maintained rather than locking in the demand portion, as it better reflects prior practice." 4 Tr 880.

In addition, the Staff does not fully support GLREA's request that the transfer price be based on the cost of renewable generation built. The Staff stated that:

> the transfer price was intended to separate the additional cost of renewable over traditional generation and treat the cost that would be associated with the generation were it not renewable the same way as traditional generation costs. With regard to PPAs, to the extent that the transfer price is higher than the cost of renewables, customers do not pay more for the renewables than they cost through the transfer price. Instead, the amount of cost included in the PSCR through the transfer price is the actual cost if lower than the transfer price. For Company-owned generation, the Company is currently (and temporarily) allowed to include through the transfer

> price the higher of the transfer price or the levelized cost of the facility. However, this does not result in higher costs being borne by customers as any "overpayment" through the transfer price is recorded to the regulatory liability under the REP and accrues to the benefit of customers, rendering the impact on them neutral over time. For this reason, GLREA witness Rafson's proposals on this matter should be rejected for the purposes of the instant case. However, revisiting the use and purpose of the transfer price, as well as its calculation, given that renewables have effectively become what the Company is building anyway, may be appropriate.

4 Tr 881-882. The Staff also noted that in the settlement agreement approved by the May 15 order, the parties agreed to participate in a transfer price technical conference. The Staff contended that by the time the reconciliation is conducted in this case, the transfer price issue may have been evaluated by persons participating in the technical conference and decided by the Commission.

MEC/NRDC noted that, according to the Staff, because Consumers operates within the MISO market, which has jurisdictions that are outside of Michigan, it is not necessary to base the transfer price schedules on Michigan-specific clean energy laws and policies. MEC/NRDC disagreed, stating that Act 235 "does not say anything about using an average MISO-wide market price to calculate transfer prices. MISO is geographically enormous and prices vary drastically among its many different local resource zones – so it is unclear that such a concept would have any usefulness at all." MEC/NRDC's initial brief, pp. 63-64 (footnote omitted).

Next, MEC/NRDC noted that the Staff states that transfer price schedules should be representative of what a Michigan electric provider would pay had it obtained the energy and capacity (the market price component) through a long-term PPA. However, MEC/NRDC asserted that on cross-examination in a DTE Electric case the Staff "acknowledged: 'It is probably unlikely that we would see any of our rate-regulated electric providers enter into a long-term contract for a natural gas combined cycle plant without . . . carbon capture and sequestration, although it is not impossible . . . that they could, it's just not likely.'" *Id*., p. 64 (quoting 2 Tr 69-

70 in Case No. U-21662). In addition, MEC/NRDC argued that the Staff failed to provide any other certain scenarios in which a combined-cycle gas plant without CCS would be built in Michigan. Therefore, MEC/NRDC asserted that it is unreasonable for the Commission to continue to base the transfer price on a proxy combined-cycle gas plant that does not have CCS.

Finally, like the Staff, MEC/NRDC noted that the settlement agreement approved by the May 15 order directed the Staff to host a symposium on transfer prices. MEC/NRDC asserted that the "workgroup has met, and Staff will be issuing a report later this summer. . . . The Commission should not approve Consumers' transfer price schedule in the meantime, because – as explained in MEC-NRDC's initial brief – there is no substantial evidence to support it and transfer prices are approved in the reconciliation case – not the plan." MEC/NRDC's reply brief, p. 10.

ABATE objected to MEC/NRDC's argument that, because the transfer price is based on the levelized cost of a new combined-cycle gas plant, the transfer price should now include the cost of CCS pursuant to state and federal rules. ABATE stated that, "[a]s this recommendation rests on the tenuous assumption that the transfer price should and will continue to be based on the levelized cost of a new combined cycle gas plant, the Commission should reject MEC-NRDC's recommendation." ABATE's reply brief, p. 4. In addition, ABATE agreed with the Staff that it is not reasonable to conclude that a combined-cycle gas plant with CCS is the most appropriate proxy given the manner in which the transfer price is calculated and the cost it is meant to reflect. ABATE stated that "there are a number of different resources which may serve as reasonable proxies for the transfer price, not to mention the myriad factors for determining the transfer price set out in MCL 460.1047(2)(b)(iv)" and "[e]xploring those options based on developments in renewable technology since the transfer price methodology was established over a decade ago is the purpose of the symposium established in Case No. U-21662." *Id*., pp. 6-7. Therefore, ABATE

recommended that the Commission reject MEC/NRDC's proposals and, instead, allow the workgroup to develop an updated transfer price methodology.

The ALJ agreed with MEC/NRDC and GLREA that the current transfer price methodology should be re-examined and possibly modified. In addition, he found MEC/NRDC's arguments persuasive that, pursuant to Act 235, a combined-cycle gas plant with CCS must replace a traditional combined-cycle gas plant as the proxy. However, the ALJ stated, "as noted by Staff, all potential proxies should be explored, such as the use of a solar facility, which MEC-NRDC found reasonable." PFD, p. 71. He agreed that the settlement agreement approved by the May 15 order directed the Staff to convene a transfer price methodology workgroup but "disagree[d] with MEC-NRDC that the Commission should reject Consumers' transfer price schedule in the meantime because MEC-NRDC contends there is no substantial evidence to support it and transfer prices are approved in the reconciliation case." PFD, p. 71.

The ALJ found Consumers' proposal for the new transfer price schedules to be reasonable, noting that the Staff's support of the proposal was persuasive. He agreed with the company that the impact on the total cost transferred to the PSCR through use of the new schedules is negligible. Additionally, the ALJ found that "there is sufficient evidence on the record in this case to approve the Company's request until the appropriate proxy for the transfer price can be determined via the symposium." *Id*., pp. 71-72. He however declined to recommend approval of MEC/NRDC's suggested changes to the transfer price methodology, asserting that these issues will be addressed in the workgroup. Finally, the ALJ disagreed with ABATE "that if the current method of determining the split between energy and demand portions of the transfer price is changed, that the proportion of demand-related costs be maintained," and instead agreed with the "Staff that maintaining the current proportional split would be more appropriate." *Id*., p. 72.

In conclusion, the ALJ recommended that:

> the Commission continue the current transfer price methodology and regulatory liability balance for Company-owned assets in the REP through December 2045 and approve Consumers' simplified transfer price schedules to replace those approved Case No. U-15805 and Case No. U-16581. This PFD also recommend[ed] that the Commission direct that the symposium ordered in Case No. U-21662 be continued to ensure it addresses and determines the appropriate proxy for the transfer price going forward and whether any modifications to the transfer price causes changes to the regulatory asset/liability that necessitates changes to the disbursement schedule of the projected final regulatory liability.

Id., pp. 72-73 (citing ABATE's reply brief, p. 11).

In exceptions, MEC/NRDC asserts that the Staff did not unequivocally support Consumers' continued use of a proxy combined-cycle gas plant without CCS and, therefore, the Commission should not rely on the Staff's support for the company's position on this issue. MEC/NRDC also states that "the modest impact of the proposed transfer price schedule on the total cost transferred to the PSCR in the short term is not a valid basis to approve the schedule if there is not substantial evidence to support it." MEC/NRDC's exceptions, p. 16. Rather, MEC/NRDC argues that the company failed to provide any evidence that a combined-cycle gas plant without CCS is a reasonable proxy for setting the transfer price.

In addition, MEC/NRDC notes that the transfer price symposium has already been conducted. According to MEC/NRDC, "[t]he draft Staff report does not make any recommendations one way or another – it simply summarizes the presentations and comments that have been submitted. There is an opportunity for comments on the Staff report, but because the Staff report is mainly a summary of presentations and comments it is unclear what the path to a decision on this issue will be." *Id*., p. 17. Thus, MEC/NRDC request that the Commission reject Consumers' proposed transfer prices and, instead, find that transfer prices must be based on a proxy combined-cycle gas plant with CCS. Alternatively, MEC/NRDC recommend revising the transfer prices to equal the

actual cost of Consumers' solar resources. In any event, MEC/NRDC does not support deferring these issues to a symposium that will not result in a decision.

In reply, ABATE contends that it is "premature at this time" to direct Consumers to include the costs of CCS in the transfer price schedule. ABATE's replies to exceptions, p. 7. ABATE asserts that "[c]onsidering the significant technological and cost developments in renewable energy resources since the transfer price was originally established, a more comprehensive approach to establishing a transfer price cost is needed than simply directing one specific utility to file a transfer price reflecting one specific resource in its REP reconciliation proceeding." *Id*., p. 8.

ABATE also objects to MEC/NRDC's claim that the transfer price should be based on a proxy combined-cycle gas plant with CCS because "any gas plant operating in Michigan past 2034 must be 90% effective in capturing and permanently storing carbon dioxide" to comply with the clean energy standard. ABATE's replies to exceptions, p. 7 (quoting MEC/NRDC's exceptions, p. 13). ABATE contends that MEC/NRDC's proposal to base the transfer price on a state standard for one specific resource that is not effective until 2034 is unreasonable. According to ABATE, "while the transfer price is meant to reflect the market cost of a long-term PPA, there is no evidence on the record that the most likely market cost of a long-term PPA is that of a natural gas resource with estimated CCS costs." ABATE's replies to exceptions, p. 9. ABATE argues that there are other options on which to base the proxy, which should be reviewed thoughtfully and visibly in a workgroup and that considers the factors in MCL 460.1047(2)(b)(iv) and the market costs of a long-term PPA.

Consumers replies to MEC/NRDC, asserting that "[r]evisiting the transfer price calculation is premature. This is especially true if the revisions were to only be applicable to Consumers Energy. Moreover, the Company maintains that if a new methodology is not adopted in this

proceeding, then the Commission's current methodology should stay in place and be used for the Company's RE Plan." Consumers' replies to exceptions, p. 14. And, responding to MEC/NRDC's concern that the symposium has already occurred and no decisions resulted from the event, the company contends that the workgroup is ongoing and the Staff's final report is not yet due. Consumers asserts that any updates to the transfer price methodology should be discussed by the workgroup—not in this proceeding.

The Commission finds the ALJ's recommendation to be reasonable and prudent and that it should be adopted. The current transfer price schedule was approved in the Temporary Order and, because of the significant passage of time, the enactment of new energy laws, and the changing energy landscape, it is fitting to revisit this issue. However, as noted by the ALJ, the most appropriate venue to explore and evaluate this issue is a workgroup that involves all rate-regulated utilities and interested persons. In the May 15 order, the Commission directed the Staff to host a symposium to explore and address the transfer price methodology and to issue a report. As above, the Commission finds the most appropriate path is for the Commission to provide additional guidance based on the issues raised in the symposium and summarized in the recently-filed report.

The Commission agrees with the ALJ that until the Commission adopts a new transfer price methodology, Consumers' proposed transfer price schedule should be approved in this case. As noted by the Staff, the current transfer price utilized by the company was adopted in Case No. U-20483 to address an issue with Consumers' regulatory liability/asset position. The Staff acknowledged that with the enactment of Act 235, Consumers is no longer required to carry a regulatory liability balance. However, the Staff contended that it is reasonable to continue the methodology, at least for the immediate case, "to balance the ICOC between a regulatory asset and regulatory liability position." 4 Tr 796. The Commission agrees.

The Commission also finds that the new transfer price schedules proposed by Consumers should be approved to replace the existing transfer price schedules approved in Case Nos. U-15805 and U-16581. The Commission finds persuasive the company's claim that the new transfer price schedules will reduce administrative burdens and potential errors and will better align with the transfer price schedules proposed by the Staff. In addition, Consumers asserted that the new transfer price schedules will have a negligible impact to the total cost transferred to power supply costs. *See*, 2 Tr 340-341. The Staff supported the company's proposal and contended that it is a "much simpler and transparent transfer price schedule than the Company's existing transfer price schedule . . . ." 4 Tr 797.

The Commission declines to approve ABATE's request that if the current method of determining the split between energy and capacity in the transfer price is changed, the portion of demand-related costs should be maintained. The Commission finds the Staff's argument on this issue persuasive. *See*, 4 Tr 880.

5. Incremental Cost of Compliance

Consumers provided the ICOC with the renewable energy standards for a 20-year period. *See*, Exhibit A-4. The company asserted that the ICOC calculation in this case is the same as the ICOC calculation in the REP amendment approved by the August 22 order; however, in this case, it includes an FCM for any new PPAs as set forth in MCL 460.1047(2)(a)(v)(C). More specifically, Consumers explained how the ICOC is calculated in Exhibit A-4, line 2:

> This line reflects all projected financing and capital costs (including a Return on Common Equity ("ROE") investment), depreciation expense, general taxes, and Operation and Maintenance ("O&M") expenses associated with the Company's investment to build renewable energy systems as part of its RE Plan to comply with 2008 PA 295 ("Act 295"), as amended by 2016 PA 342 ("Act 342") and Act 235 and the investments made to provide resources for customers electing to participate in a Voluntary Green Pricing Program ("VGP"), as authorized by Section 61 of Act 342.

2 Tr 176-177. In addition, the company asserted that the projected capital expenditures, PPA expense, and O&M expense in its amended REP are based on projects already approved by the Commission and in commercial operation. Regarding the items on line 9 in Exhibit A-4, Consumers stated that they are the estimated value of federal tax credits to encourage the development of renewable energy that the company expects to receive during the REP period.

GLREA contended that the existing federal tax credits will not continue through the entirety of the REP period. GLREA asserted that federal tax:

> incentives at most will continue through the IRA [federal Inflation Reduction Act] incentive period which tails off to zero starting in 2032. Thus, no more than 7 years of federal tax incentives should be considered.
>
> It is our opinion that the company's assumed tax credits in the REP of approximately $8.9 billion are both extremely high and fail to show the impact of the REP on customers. The calculations like the LCOE is low by the amount of the tax credits assumed. If these incentives are not received the result would likely greatly increase the cost recovery and result in much higher customer rates.

4 Tr 624-625.

Consumers noted that GLREA assumes that there will be zero tax credits for projects that will reach commercial operation after 2032. The company stated that "the IRA establishes a phase out for the credits, by 25% annually from 100% to 0% in the latter of 2032 or the year in which Treasury determines that annual greenhouse gas emissions from the production of electricity in the US are equal to or less than 25% of the annual greenhouse gas emissions for 2022." 2 Tr 197. However, Consumers contended that there is no published forecasted data that predicts this date and, in the past, the U.S. government has extended sunset provisions for renewable energy tax credits.

The ALJ "agree[d] with Consumers that, based on the information available when this case was filed, Consumers inclusion of federal tax incentives after 2032 was reasonable. If circumstances change, the Company may update its [ICOC] calculation in the future." PFD, p. 74.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation to be reasonable and prudent and that it should be adopted.

6. Revenue Recovery Mechanism

Consumers asserted that it is not proposing a revenue recovery mechanism to recover its ICOC in this case. The company explained that:

> [w]hile the Company's filing reflects that the Company will experience incremental costs of compliance on an annual basis through 2034, the incremental costs of compliance turned decidedly negative in 2035 through 2041, resulting in a projected regulatory liability at the end of the 20-year RE Plan period. As such, a levelized revenue recovery mechanism, as provided for in MCL 460.1045(3), for the 20-year period is unnecessary.

2 Tr 58. Consumers also contended that if it were to implement a revenue recovery mechanism for a shorter period, in effect, it would pre-pay for company-owned renewable energy resources that would benefit future electric customers and may require a large revenue recovery mechanism credit surcharge for future beneficiaries of company-owned renewable energy resources. Furthermore, Consumers stated that:

> [i]n addition to following principles of cost causation, the Company also recognizes that it may ultimately solicit and execute contracts for a higher percentage of renewable energy resources as compared to its proposed plan. That scenario would lead to far lower incremental costs of compliance and, ultimately, an even greater need to avoid the implementation of a revenue recovery mechanism.

2 Tr 58. In the event there is a large regulatory liability balance in 2037 and beyond, the company asserted that it will adjust the revenues to minimize the balance. For example, Consumers stated that potential options for reducing the balance "include a reduction to the transfer price and/or the

implementation of a credit surcharge. However, given the 20-year RE Plan period and the periodic filing of RE Plan Amendments, the Company has sufficient time to address that potential in future RE Plan Amendment filings." 2 Tr 59; *see also*, Consumers' initial brief, pp. 37-38.

MEC/NRDC contended that, according to Consumers, the company will have a regulatory liability balance of approximately $49.9 million at the end of 2024, a regulatory asset until 2034, and then will have a regulatory liability until 2045, with a final balance of $332.7 million. MEC/NRDC noted that the company plans to forgo a surcharge when it has a regulatory asset because the company expects to have a regulatory liability in the late 2030s. MEC/NRDC stated that, when Consumers has a regulatory liability, it will "limit transfers of costs to PSCR to levelized cost of renewable energy from 2034 in order to minimize the accrual of a regulatory liability." 2 Tr 408 (citing 2 Tr 187-188). MEC/NRDC supported the company's plan to forgo surcharges in anticipation of a regulatory liability. However, if the Commission accepts MEC/NRDC's recommendations regarding the transfer price, the accumulation of a large regulatory asset may be eliminated. In that case, MEC/NRDC suggested that "the Commission direct the Company to either eliminate the use of a regulatory liability or to early create an appropriate sur-credit to disburse the projected regulatory liability by 2045. This analysis should be done in Consumers Energy's next amendment of its REP." 2 Tr 409.

The ALJ "agree[d] with Consumers that regular REP filings will allow for sufficient scrutiny and adjustment of any regulatory asset or liability occurring over the plan period. As noted above, this PFD recommends that the changes proposed by MEC-NRDC to the transfer price be rejected for now. As such, [MEC/NRDC]'s concerns regarding the future regulatory liability are moot." PFD, p. 76.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation to be reasonable and prudent and that it should be adopted.

7. Voluntary Green Pricing Program

Consumers noted that in the August 22 order, the Commission removed the 1,000 MW limit on the addition of new wind and solar facilities to serve the Renewable Energy Program so long as the company achieves subscriptions totaling 75% of the expected energy production. Accordingly, Consumers proposed "to build, own, and operate nearly 1.1 GW of VGP solar facilities located in the state of Michigan." Consumers' initial brief, p. 41; *see also*, 2 Tr 180. The company also noted that the residential Renewable Energy Program and the Green Giving Program were commenced on January 1, 2025, and the company "has projected subscription rates for each of these new programs which support the addition of renewable energy resources which, all else being equal, support a lower cost RE Plan for non-subscribing customers." 2 Tr 67.

GLREA asserted that "the obligation of not building new energy resources until subscriptions total at least 75% of expected energy production will create an unreasonable burden on residential and small commercial customers . . . ." 4 Tr 615. By contrast, GLREA noted that for the industrial VGP program, any capacity that is not used for VGP will be used to comply with the RPS as a company-owned asset. GLREA opined that this approach is much more reasonable than Consumers' residential offering and should be provided to all customer classes.

However, GLREA objected to Consumers' industrial VGP program, stating that "[t]he program improperly provides for the building of renewable energy assets specifically for industrial customers. Presently, between the Economic development tariff and VGP, nearly ½ of industrial clients have effectively opted out of Consumers legacy generation pool leaving the commercial and residential customers to pay for these more expensive generation costs." 4 Tr 616.

Furthermore, GLREA argued that the company's commercial/residential VGP is not equivalent in value to the industrial VGP, explaining that the generation assets Consumers proposed for the commercial/residential VGP are twice as expensive as the industrial VGP LCOE.

In response to GLREA, Consumers stated that the 75% subscription requirement was approved in the December 9, 2021 order in Case No. U-20984 to ensure that the addition of VGP assets did not outpace subscriptions and to minimize the cost impact on PSCR customers. The company noted that the August 22 order continued the 75% subscription policy. Moreover, the company contended that:

> [a]ll customer types (residential, small business, commercial and industrial) participating in the Renewable Energy Program are served by a single resource pool of renewable energy facilities. Therefore, the 75% subscription level for new assets will be achieved through subscriptions from residential, small business, and commercial and industrial customers. As such [GLREA]'s concerns are unwarranted.

2 Tr 108. Additionally, Consumers asserted that the Renewable Energy Program is available to all customers, regardless of class, and no customer class has an advantage in price. The company disagreed with GLREA that non-subscribing customers subsidize VGP customers; rather, "VGP customers are required to pay for all costs associated with VGP programs." 2 Tr 109.

The ALJ found GLREA's arguments unpersuasive. He stated that "[i]t bears emphasizing that pursuant to MCL 460.1061, VGP programs are optional and VGP customers are required to pay all costs for the program, such that non-participating customers are not subsidizing VGP customers." PFD, p. 79.

Next, Consumers proposed to expand its Solar Gardens Community Solar Program by constructing, owning, and operating an incremental 5.5 MW of solar facilities. The company stated that:

> [t]his expansion is projected based on proxy facilities with a net capacity factor of 24%, capital costs of approximately $15 million, and a levelized cost of approximately $98/MWh. The filing assumes the Solar Gardens expansion will consist of 2.5 MW in 2026 and additional 3.0 MW in 2030. All of the Solar Gardens expansion is expected to qualify for 100% PTCs [production tax credits] and to be ultimately fully subscribed.

2 Tr 181.

GLREA objected to Consumers' proposed expansion of the Solar Gardens Community Solar Program, asserting that the program is "a far worse deal for residential customers" than what the company offers industrial customers. 4 Tr 621. GLREA argued that instead of expanding the Solar Gardens program, the company should implement community solar projects to allow customers to receive similar pricing as VGP customers.

Consumers responded, stating that it is not requesting to expand the Solar Gardens program. Rather, the company contended that it "has existing renewable energy assets of 4.5 MW currently in operation under the Pilot Solar Gardens Program which has a cap of 10 MW." 2 Tr 116. Consumers stated that the Pilot Solar Gardens program is 99.8% subscribed and the company is proposing to increase the solar capacity by 5.5 MW to the 10 MW cap by 2030. Consumers asserted that the Solar Gardens program is a voluntary program for customers and noted that there is an alternative program if customers are seeking a lower cost subscription.

The ALJ stated that, "[a]s was the case with the REP VGP concerns discussed above, GLREA appears to have a basic misunderstanding of how the Company's VGP programs for residential customers currently operate. As such, this PFD finds that GLREA's general concerns with the structure of the Solar Gardens program should be dismissed." PFD, p. 80.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation to be reasonable and prudent and that it should be adopted.

a. Voluntary Green Pricing Credits

GLREA noted that it proposed changes to the VGP program credits but acknowledged the Staff's "well-founded rebuttal in response." GLREA's initial brief, p. 17. However, GLREA requested that the Commission order a workgroup to determine if interested parties can reach common ground regarding VGP charges and credits.

Consumers objected to GLREA's request to modify the company's VGP program credits in this case, asserting that the VGP credits should be reviewed in Consumers' biannual VGP case in the fall. The company stated that "[t]his issue is not relevant to the Company's Amended RE Plan. Moreover, it is unclear as to why a workgroup should be established to discuss and evaluate the various options for the structure of VGP pricing in the future." Consumers' initial brief, p. 44 (citing 2 Tr 114); *see also*, Consumers' reply brief, p. 9.

The ALJ agreed with Consumers that VGP program charges and credits are properly addressed in the company's next VGP biannual filing. In addition, the ALJ stated that he "agree[d] with Consumers that programmatic and pricing provisions for VGP programs are 'unique to that electric provider and should be addressed in their own dedicated VGP proceedings' and not as part of a workgroup process." PFD, p. 81 (quoting Consumers' initial brief, p. 44).

GLREA excepts, asserting that:

> [w]hile specific pricing is certainly specific to each electric provider, the pricing structure of the VGP program (which currently consists of a premium based on the cost of renewable energy, and two credits – one for energy and one for capacity) is common between electric providers and could be changed in a consistent manner across electric providers. GLREA's proposal provides for the Commission's approval of the structure and specific pricing in the energy provider-specific VGP cases. However, GLREA continues to recommend an industry-wide workshop process to focus upon common VGP pricing issues.

GLREA's exceptions, p. 25 (citing 4 Tr 588).

In reply, Consumers states that "it is unclear what benefit this industry-wide workgroup would provide. Each electric provider's VGP programs are unique to that provider. Any changes to these programs should be addressed in the provider's dedicated VGP proceeding." Consumers' replies to exceptions, p. 14.

The Commission finds persuasive the ALJ's recommendation that GLREA's request for a workgroup should be denied. As noted by the company, "[e]ach electric provider's VGP programs are unique to that electric provider and should be addressed in their own dedicated VGP proceedings." Consumers' initial brief, p. 44 . The Commission agrees and adopts the ALJ's recommendation.

b. Community Solar

GLREA argued that Consumers' REP should have addressed the issue of community solar. According to GLREA, "Community Solar, if done like Maine or Minnesota, could represent 800-1,000 MW of solar generation and therefore be a significant contribution to achieving the RPS at little or no cost to the company and will result in lower cost than presented in this REP." 4 Tr 614. In addition, GLREA recommended options for compensating community solar customers and suggested that the RECs be included as part of compliance with the RPS.

The ALJ noted that several witnesses responded to GLREA's recommendations, however he "agree[d] with Consumers' overarching argument that specific issues concerning VGP and community solar programming, cost, and credit structures should be addressed as part of Consumers['] next VGP filing later in 2025." PFD, pp. 81-82.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation to be reasonable and prudent and that it should be adopted.

8. Co-Located Energy Storage

a. Ownership of Energy Storage Resources

MEIU requested that the Commission condition approval of Consumers' request for *ex parte* approval of energy storage resources on the following: (1) the competitive procurement process must utilize an IA, (2) a 50/50 ownership split for third-party and company-owned resources, and (3) the implementation of a process to update the company's LCOE target to reflect prevailing market conditions and to reevaluate whether the LCOE is the most appropriate metric for establishing an energy storage cost threshold. *See*, 4 Tr 638. Although MEIU supported the idea that energy storage may provide significant value to the grid, MEIU expressed concern "that the magnitude of the amendments proposed is significant and warrants careful examination to avoid exposing ratepayers to unnecessary costs and risks while also fostering a competitive environment for project developers." 4 Tr 663. Additionally, MEIU contended that the company's proposal to only co-locate energy storage additions "with Company-owned renewable assets is unnecessarily restrictive and may preclude opportunities for savings from a broader competitive procurement of energy storage resources." 4 Tr 663.

MEIU also objected to Consumers' claim that it can only implement energy storage projects that share a point of interconnection with a company-owned renewable energy system because it would be too difficult to manage coordination of energy storage operations at a third-party-owned facility. MEIU stated that it:

> agree[s] that the Company may not be able to *require* any existing renewable project to simply add storage, particularly if the project is owned by a third party via a PPA. However, that does not preclude the Company from exploring the feasibility of this option with existing counterparties. It also does not preclude the Company from allowing existing third-party project owners to propose energy storage additions as part of a competitive solicitation process.

4 Tr 665 (emphasis in original). In addition, MEIU asserted that if the renewable energy facility and the energy storage facility are owned by the same third party, there would be no coordination issues, and cited the Century Oaks Energy Storage LLC tolling agreement as an example.

Furthermore, MEIU argued that Consumers should not limit the resource procurement process to surplus energy storage. MEIU contended that "even if the Commission authorizes the use of excess interconnection capacity for battery energy storage located at Company-owned renewable asset sites, this should not limit the Company's ability and obligation to pursue other energy storage options that may be more cost-competitive or advantageous for other reasons." 4 Tr 666. MEIU cited, for example, the retirement of D.E. Karn Units 3 and 4 and noted the opportunity to interconnect resources using the generator replacement process, which would be quick and economical. Although MEIU acknowledged that "the opportunity to optimally integrate energy storage is likely best evaluated through a comprehensive IRP process," MEIU asserted that Consumers' deployment of energy storage resources "should be available to both utility-owned and third-party resources, instead of being narrowly limited to Company-owned energy storage projects." 4 Tr 667.

In response to MEIU's recommendation that Consumers expand opportunities for procurement of third-party-owned energy storage projects, the company generally agreed, noting that it has already contracted for 400 MW of battery energy storage systems (BESSs). Consumers stated that it also "will be considering hybrid projects as part of its Independent Auditor ("IA") led solicitations." 2 Tr 89. However, the company asserted that contracting for third-party BESSs at a company-owned renewable energy resource site or owning BESSs at a third-party renewable energy resource site would be ineffective and suboptimal because Consumers lacks the ability to manage the third-party system and select the lowest cost renewable energy resources.

Consumers also objected to MEIU's request that the company's competitive procurement process include an IA. According to the company:

> [a]n IA is appropriate in situations where the Company needs to fairly compare products or services it is proposing to provide with similar products or services that can be procured from a third party. The Company does not manufacture BESS components and does not perform construction activities with its direct workforce; therefore, it is not offering these services into a competitive solicitation and an IA would result in needless expense while providing no value to customers.

2 Tr 234.

Additionally, Consumers disagreed with MEIU's proposed 50/50 ownership split for energy storage resources. The company asserted that all of the proposed energy storage is co-located, hybrid, or surplus. Consumers explained that:

> [c]o-located, hybrid, and surplus energy storage is installed at existing interconnections owned by the Company. It is the Company's understanding of MISO's rules that the surplus interconnection agreement can only be entered into with the Interconnection Customer from the primary Interconnection Agreement. It is the understanding of the Company that MISO does not allow multiple interconnection customer parties to a single Interconnection Agreement, so a third-party interconnection customer could not interconnect under the Company's Interconnection Agreement. Furthermore, surplus interconnections are unique and are forfeited when the existing Interconnection Agreement is terminated. The dependency of the surplus interconnection agreement on the existing renewable energy interconnection agreements creates many complexities, making it infeasible for third parties to own and operate BESS facilities that rely on Company-owned interconnections as proposed in this RE Plan.

2 Tr 234. Moreover, the company stated that the LCOE is the standard by which Consumers compares projects. Although the company is not opposed to considering other metrics, Consumers asserted that it does "not expect a different metric to result in a materially different recommendation of one or another project." 2 Tr 235.

Regarding MEIU's proposal of a 50/50 ownership split of energy storage resources, the Staff contended that it may not be necessary to require a strict 50/50 split but asserted that 100% company ownership would not be prudent. The Staff stated that:

> in light of the significant costs associated with activities necessary to meet the requirements of [Act] 235, Staff's opinion is that the Company should be choosing the most economical and valid resources that meet its requirements, regardless of whether they are third-party or Company-owned. Staff would not support the Company entering into PPAs that are more costly than Company-owned resources, or vice versa, for the sole purpose of meeting a 50/50 requirement. Likewise, Staff also expects any Company-owned project, that successfully wins in a competitive request for proposal process (RFP), to be built for the cost that it was bid at and continues to monitor the actual costs of Company-owned projects through annual renewable reconciliations. Projects should be chosen primarily on economic merit, but should also consider other components, such as ability to meet timelines, risk associated with the project, financial stability of contractor, etc., as these all can ultimately result in additional costs for rate payers.

4 Tr 809-810. The Staff also contended that it will be necessary for Consumers to include third-party PPAs in all future RFPs to meet the aggressive portfolio standards set forth in Act 235.

MEIU opined that Consumers improperly asserts that the company will own all storage resources procured under the amended REP. Specifically, MEIU noted that the company argues that an IA is unnecessary because Consumers is only procuring BESS components or engineering, procurement, or construction services. Rather, MEIU asserted that an IA is necessary "to fairly compare products or services" because MEIU "is advocating for third-party ownership of storage resources." *See*, MEIU's initial brief, p. 21 (quoting 2 Tr 234).

In addition, MEIU disputed Consumers' claim that it would not be prudent for the company to contract for third-party BESSs at a company-owned renewable energy site or to own BESSs at a third-party renewable energy resource site. MEIU asserted that the company appears to conclude that third-party BESSs must be co-located with Consumers' existing renewable energy resources or that company-owned BESSs must be co-located with a third party's existing renewable energy resource, both of which are not manageable for Consumers. However, MEIU contended that Consumers':

> objections alleging insurmountable operational difficulties are clearly answered by a scenario in which storage procurement opportunities are opened to third parties

> already currently operating renewable energy resources under a PPA with the Company. The Company has provided no reason why it expects that third parties operating renewable energy resources would not have the same surplus interconnection rights or opportunities that it asserts access to via its owned resources.

MEIU's initial brief, p. 23.

MEIU also disagreed with Consumers' claim that a 50/50 ownership split of energy storage resources will limit the company's ability to procure the lowest cost storage resources. MEIU contended that "witness McDonnell's testimony shows that the empirical likelihood that a well-designed ownership split would end up compelling the Company to acquire uneconomic/uncompetitive third-party BESS[s] is very low." *Id*., p. 24.

The ALJ stated that "[f]or reasons already discussed, this PFD recommends rejection of a 50/50 ownership requirement, or any of MEIU's other recommendations, should the Commission include co-located storage as a renewable resource in this REP." PFD, p. 87.

MEIU objects, asserting that the PFD "fails to address or otherwise engage with MEIU's broader arguments regarding third-party ownership of co-located storage, and its apparent rejection of MEIU's recommendation that the opportunity to provide co-located storage be available to third parties and not just the Company is at odds with the PFD's recommendations with respect to wind resources." MEIU's exceptions, p. 7. MEIU notes that the ALJ found that Consumers' proposed 100% ownership of wind resources may prevent healthy competition and cost-effective projects. MEIU opines that, "[i]f this is the case with wind resources, it is hard to imagine why it would not also be the case with co-located storage resources, and the PFD certainly provides no reasons to make such a distinction." *Id*., pp. 7-8. MEIU requests that the Commission consider MEIU's arguments regarding third-party ownership of co-located energy storage acquired

through the company's REP, opportunities for third-party-owned co-located energy storage, and a target 50/50 ownership split.

Similar to the Commission's conclusion in the "Company-Owned Wind Energy Resources" section above, the Commission finds that 100% company-ownership of energy storage resource assets is not reasonable because it impedes healthy competition and may result in Consumers' acquisition of expensive assets. However, the Commission finds it imprudent to order an explicit 50/50 ownership split. Rather, the Commission finds that Consumers should implement a competitive bidding process for energy storage resources and should actively solicit third-party PPAs in all its future RFPs in order to select the most feasible and economical projects regardless of ownership. The Commission agrees with MEIU that the company should use an IA in its competitive bidding process, and as noted above, plans to review the competitive procurement guidelines in the near future to, in part, address concerns raised by MEIU.

MEIU requested that the Commission implement a process to update the company's LCOE target and reevaluate whether the LCOE is the most appropriate metric for establishing an energy storage cost threshold. In the "*Ex Parte* Approval and 140% Levelized Cost of Energy Multiplier" section above, the Commission found that Consumers' wind and solar LCOE targets should be regularly updated in the company's subsequent REP amendments.

b. Energy Storage Cost Recovery

Consumers asserted that energy storage should be included in the amended REP because it provides value, such as energy, capacity, ancillary services, transmission, and distribution benefits. In addition, the company contended that energy storage helps to enable renewable energy—i.e., it reduces curtailment of renewable generation assets and increases the utilization of renewable energy infrastructure. Consumers stated that, "most importantly, off-peak renewable energy that is

stored and used during on-peak hours yields IRECs [incentive renewable energy credits] which will be used to demonstrate REC Portfolio Standard compliance which is the key objective of the Company's RE Plan." 2 Tr 217; *see also*, Consumers' initial brief, pp. 46-47. The company asserted that it plans to pursue energy storage projects only if they share a point of interconnection with a renewable energy system.

Consumers projected an LCOE of $143.54/MWh for energy storage resources with a COD of January 1, 2028. According to the company, "[t]his cost is based on the costs from the recently executed Power Purchase Agreement with Century Oaks Energy Storage LLC that has been reviewed and approved by the [Commission] in Case No. U-21090." 2 Tr 218. Consumers used the costs from Case No. U-21090 as a target for energy storage projects in the amended REP and proposed to recover all costs of energy storage projects through the REP cost of compliance.

The Staff expressed several concerns regarding the company's proposed cost recovery for co-located energy storage projects: (1) "storage is not listed under 'renewable energy resource' at MCL 460.1011(g);" (2) "only renewable energy resources are included in the renewable energy cost recovery mechanism first established in Public Act 295 of 2008 (PA 295), as amended by Public Act 342 of 2016 (PA 342) and mostly maintained in PA 235;" and (3) MCL 460.1022(3) states that an amended REP must include a forecast of renewable energy resources needed to comply with the RPS, and energy storage is not listed in the definition of "renewable energy resource" in MCL 460.1011(g). 4 Tr 792-793.

The Staff noted that energy storage is mentioned in MCL 460.1039(2)(c), which discusses incentive RECs for renewable energy electricity generated during off-peak hours and stored in an energy storage system. The Staff asserted that MCL 460.1101(4) states that a utility may recover

the costs of contracts for eligible energy storage in the utility's base rates. Therefore, the Staff stated that:

> [b]eing that storage was clearly mentioned in the same statute as a means to create incentive credits and that established a 2,500 MW storage target but also did not define it as a renewable energy system or specifically state it should utilize the renewable cost recovery mechanism, Staff submits that the most obvious solution is that storage assets should be recovered in base rates, through a general rate case.

4 Tr 793-794.

The Staff contended that cost recovery remains the same even if the energy storage system is co-located with a renewable energy asset. The Staff stated that "tying cost recovery of a co-located storage facility to that of the traditionally defined renewable energy resource it is co-located with could result in inefficient operation of that storage asset" because:

> [i]f the storage asset where [sic] to be connected to the Direct Current (DC) side of the renewable asset point of interconnection (POI) and only charge from the renewable energy resource that it is co-located with in an effort to effectively call it a single resource for purposes of cost recovery, as opposed to charging directly from the distribution or transmission grid, it would mean that charging would be limited to the intermittent generation of the renewable energy system. Regardless of whether the storage is on the DC side or connected to the Alternating Current (AC) side of the renewable asset POI, the Company can still allocate costs to each of the assets even if they share components within the common POI.

4 Tr 794 (footnote omitted). Thus, the Staff recommended that Consumers install energy storage assets to allow it to optimize charging using both a shared interconnected asset and/or the grid. The Staff argued that, without this configuration, the value of energy storage to the broader grid is diminished.

In response to the Staff's claim that the costs of energy storage must be recovered through base rates, Consumers disagreed, asserting that the costs can be recovered as an ICOC in the REP pursuant to MCL 460.1047(2)(a)(vii). The company also disagreed with the Staff's assertion that

a co-located storage facility with a traditional renewable energy source may result in the inefficient operation of storage assets. Consumers stated that:

> [a]n energy storage asset is typically designed to discharge over 4 hours and charge over the same period. This would allow, under normal operations, the energy storage asset to charge and discharge once a day without impact to a solar asset and only minor impact from full production of a wind asset (a co-located energy storage asset with wind will not be able to charge/discharge every day due to the nature of wind generation).

2 Tr 228. Consumers also contended that energy storage assets are sited to best utilize the interconnection facilities and to best use the traditional renewable energy asset, which is accomplished by "optimizing the sizing of the energy storage to maximize energy, capacity, and renewable energy credit values for a given project." 2 Tr 228. By optimizing the energy storage asset, the company averred that the asset will serve as an enabler to improve the functionality of the traditional renewable generation asset and will not impede the efficiency of the energy storage facility.

Responding to the Staff's claim that an energy storage system is not a renewable energy resource under Act 235, the company noted that MCL 460.1011(i) defines "renewable energy systems" as a "facility, electricity generation system, or set of electricity generation systems that use 1 or more renewable energy resources to generate electricity or steam." Consumers' initial brief, p. 46 (quoting MCL 460.1011(i)). Consumers argued that "[a]n energy storage system charged from a renewable resource falls within the definition of a 'renewable energy system' because it is a facility that uses '1 or more renewable resources to generate electricity or steam.'" *Id*. For example, the company explained that if a co-located energy storage system is charged by a renewable energy resource, such as a solar PV facility, and the energy storage system injects the generated and stored energy into the transmission or distribution system:

> whether the energy is being provided to the grid directly from the solar PV facility or from the energy storage system that has been charged from the solar PV facility, the energy is being generated from "solar and solar thermal energy," which are renewable energy resources under MCL 460.1011(g)(ii). In addition, energy storage resources are not listed as one of the exclusions from the definition of "renewable energy systems" under MCL 460.1011(j).

Consumers' initial brief, p. 47.

In addition, the company contended that MCL 460.1101(4) does not prohibit recovery of co-located energy-storage resource costs through the REP. Consumers explained that MCL 460.1101(1) "requires an electric provider to 'construct or acquire eligible energy storage systems or enter into eligible energy storage contracts to meet its share of a statewide energy storage target of a combined capacity of at least 2,500 MW.'" Consumers' initial brief, p. 47 (quoting MCL 460.1101(1)). Then, the company noted that MCL 460.1101(4) states that:

> a rate-regulated electric provider "shall submit to the commission for review and approval eligible energy storage contracts entered into to meet its share of the statewide storage target," and if the Commission approves the eligible energy storage contracts, the Commission must "authorize the electric provider to recover the costs of the contract in the electric provider's base rates."

Id. (quoting MCL 460.1101(4)).

Next, Consumers stated that pursuant to MCL 460.1101(9)(b), an "eligible energy storage system" is an "an energy storage system that is located within the local resource zone or the locational deliverability area, as defined by the appropriate independent system operator or regional transmission organization, in which the electric provider is subject to capacity demonstration obligations pursuant to section 6w(8)(b) of 1939 PA 3, MCL 460.6w." *Id*. (quoting MCL 460.1101(9)(b)). Consumers contended that pursuant to the above statutory provisions:

> the statewide storage target storage systems are not limited to those systems that are co-located with renewable energy resources, and the Company plans to meet its share of the statewide energy storage target excluding co-located storage. So while MCL 460.1101 requires the Commission to authorize the recovery of eligible energy storage contract costs in base rates where those contracts are meant to

> support the statewide storage target, this does not prevent the recovery in the RE Plan of co-located energy storage resources that support meeting the REC standard by reducing renewable energy curtailment, avoiding energy waste, and supporting the creation of additional RECs and incentive RECs.

Consumers' initial brief, pp. 47-48 (citing 2 Tr 91).

The Staff disagreed, asserting that if the Legislature intended to consider energy storage resources as a renewable energy system and allow cost recovery of these assets under the cost recovery mechanism in MCL 460.1047 and 460.1049, the Legislature would have explicitly included energy storage resources in the definition of "renewable energy resources" in MCL 460.1011(g). Additionally, the Staff stated that it "is not convinced by the argument that co-located storage increases the quality and reliability of renewable energy. It simply allows it to be stored when not needed on the grid." Staff's initial brief, p. 4. The Staff asserted that the company failed to provide a clear explanation of what it considers to be co-located. In any event, the Staff argued that "[DC] coupled storage with renewable energy would not allow the storage to be optimally utilized to provide benefit to the grid as a whole. Thus, recovery of co-located storage should not be approved in this plan case; rather, it should be approved in base rates." *Id*.

The ALJ agreed with the Staff that the costs for energy storage, including co-located energy storage, should be recovered in base rates. He stated that:

> Act 235 speaks directly to the issue of cost recovery of energy storage at MCL 460.1101(4). The statute uses the word "shall" and therefore indicates a mandatory directive. The language of MCL 460.1101(4) is clear and unambiguous and reflects the Legislature's intent that energy storage costs should be recovered in base rates. Consumers' arguments that subsection 4 only refers to contracts for energy storage that are used to meet Act 235's energy storage goals are unavailing.

PFD, pp. 92-93 (footnotes omitted).

The ALJ also disagreed with Consumers' claim that because a co-located energy storage facility uses one or more renewable energy resource to generate electricity or steam it is a

renewable energy system pursuant to MCL 46.1011(i). He opined that "[e]nergy storage does not generate electricity, rather it is a technology that absorbs, stores, and releases energy." PFD, p. 93 (citing MCL 460.1005(i), 460.1221(j), and 460.1039(2)(c)). Similarly, the ALJ found "[t]he Company's point that energy storage resources are not listed as one of the exclusions from the definition of 'renewable energy system' under MCL 460.1011(j) is dispatched under the doctrine *Inclusio Unius Est Exclusio Alterius*: since co-located energy storage is not mentioned in the list of exclusions, it is implied that the Legislature did not intend to exclude it." *Id*.

Moreover, the ALJ disputed Consumers' claim that co-located energy storage resource costs may be recovered through the REP. He stated that, pursuant to MCL 460.1047, co-located energy storage resource costs are optional and not "necessarily incurred" to ensure the quality and reliability of renewable energy required to meet the RPS. PFD, p. 93 (citing MCL 460.1047(2)(a)(iv)).

Finally, the ALJ declined to recommend approval of the Staff's request that Consumers install energy storage assets in a manner that will allow the company to optimize charging using both the shared interconnection asset and/or the grid. He stated that "such a directive [is] unnecessary at this time since the Company asserts that its energy storage assets are optimized to maximize energy and capacity. While the Company also states that it optimizes its energy storage to maximize renewable energy credit values for a given project, it is unclear how this would impact the efficiency of the storage asset." PFD, p. 94.

In exceptions, Consumers states that "[w]hile the Company continues to believe that its proposal to include co-located storage costs as part of future [REP] costs of compliance is consistent with applicable law as explained in the Company's Initial Brief and Reply Brief, the Company withdraws its request in this case for Commission authorization to include co-located

energy storage in the [REP]." Consumers' exceptions, p. 8; *see also*, Consumers' replies to exceptions, p. 15.

In light of Consumers' withdrawal of its request for cost recovery for co-located energy storage projects, the Commission finds that the company shall reflect this change in subsequent biannual amended REP filings and its 2025 REP reconciliation.

9. Financial Compensation Mechanism

Consumers stated that its REP includes the recovery of FCM costs through the PSCR mechanism, which is authorized by MCL 460.1047(2)(a)(v)(C), for all contracted renewable energy resources executed after June 30, 2024, pursuant to MCL 460.1028(8). In addition, the company noted that MCL 460.1047(2)(a)(i) states that the electric provider's authorized rate of return on renewable energy resources be used to comply with the renewable energy standard. Specifically, Consumers asserted that its "FCM is calculated using the pre-tax weighted average cost of permanent capital, as set forth in MCL 460.1028(8), to annual contract payments. Recovery of FCM costs related to eligible contracts will be included in Consumers Energy's PSCR mechanism." Consumers' initial brief, p. 51 (citing 2 Tr 48, 81).

The Attorney General noted that in Case No. U-20165, an FCM was proposed to address an issue with PPAs that was identified by Consumers. She stated that the FCM established in Case No. U-20165 was included in the settlement agreement in Case No. U-21090 and approved by the June 23 order with the following modifications: (1) the FCM would be extended at the after-tax weighted average cost of capital (WACC) of 5.62% and updated in electric rate case orders; (2) the FCM was approved for all new PPAs but not PPA amendments, PURPA PPAs, VGP PPAs, or a PPA executed under the REP; and (3) the FCM would be subject to price caps. *See*, 2 Tr 462-463. Therefore, the Attorney General argued that, pursuant to the terms of the settlement

approved by the June 23 order, the company may not recover FCM costs for contracts executed under the REP, as is proposed in this case. In addition, she requested that the Commission direct Consumers "to not include an FCM for any new PPA contract attached to future renewable energy projects required to meet its VGP and RE Plan requirements." 2 Tr 469; *see also*, Attorney General's initial brief, pp. 38-41.

The company acknowledged that in Case No. U-21090, it "agreed to not apply the IRP FCM to PPAs entered into under the RE Plan," however Consumers argued that "[t]he enactment of Act 235 changed the statutory framework" and it now authorizes an FCM for a rate-regulated electric provider that is limited to PPAs for renewable energy resources or third-party contracts for energy storage systems or clean energy systems with non-affiliated companies. Consumers' initial brief, p. 52. The company asserted that "contrary to the contention of the Attorney General, the FCM calculation is not limited to the Company's prevailing WACC, and the Company's eligibility is not subject to Commission discretion. Thus, the Company's FCM should be authorized." *Id*.

The ALJ agreed with Consumers that the Attorney General's argument should be rejected. He noted that:

> [w]hile Consumers did previously agree pursuant to the settlement agreement that the FCM would not apply to any PPA's executed under the REP, among other restrictions, Consumers' agreement was made in the context of a second contested case challenging whether Consumers should have any FCM, which case was prosecuted when the applicable statute provided that the Commission had the discretion to either approve or not approve an FCM. Clearly, Consumers would not agree to the limited settlement FCM terms approved in the prior IRP cases today when all of the FCM terms under the revised statutes were available to it without any contest.

PFD, pp. 96-97. In addition, the ALJ noted that Act 235 states that the provisions of the act "'appl[y] to any contract entered into after June 30, 2024'." *Id*., p. 97 (quoting MCL 460.1028(8)).

ABATE noted that, for non-VGP renewable energy PPA contracts that the company executed prior to June 30, 2024, but are eligible for an FCM through prior Commission orders, Consumers recovers the contract price through the PSCR mechanism and the FCM costs through a surcharge. However, ABATE stated, for renewable energy resources contracts entered after June 30, 2024, the company proposes to recover the contract costs and the FCM costs through the PSCR mechanism. ABATE contended that Consumers has not provided an explanation for this change. Moreover, ABATE argued that:

> this change would reduce transparency for ratepayers relative to the current FCM surcharge method. Transparency into the rate impact of the FCM should be maintained, particularly as the amount of the FCM is projected to increase significantly in future years. In addition, the Company has not explained its intention regarding the allocation of the FCM if it is recovered through the PSCR.

4 Tr 725.

In response, Consumers asserted that it evaluated several options for recovering FCM costs and, because one of the goals of the amended REP is to avoid implementation of a revenue recovery mechanism, the company determined that it would be prudent to recover FCM costs through the PSCR mechanism. Additionally, Consumers contended that it appears that "[ABATE] is recommending the FCM that is authorized pursuant to MCL 460.1028(8) be recovered through the methodology established for the prior FCM mechanism resulting from the 2016 energy laws." 2 Tr 80. The company argued that the previous Commission-established FCM methodology is not appropriate for the newly established FCM in Act 235 because it would result in a significant increase in the surcharge and carrying charges.

Consumers also objected to combining the two FCM methodologies because:

> [t]he calculation methodology and resource type applicability for each of the FCMs are different. The existing FCM surcharge, established in Public Act 341 of 2016, was generally applicable to contracts established pursuant to the Company's IRPs and was capped at the Company's weighted average cost of capital ("WACC").

> Specifically, MCL 460.6t(15) allowed the Commission to **consider** and authorize a FCM which could not exceed the Company's WACC. Further, it was not limited to renewable energy resources, it was applicable to all PPAs with non-affiliated companies.

2 Tr 81 (emphasis in original).

However, the company agreed with ABATE's request that Consumers should allocate a portion of the FCM costs to capacity. Consumers stated that it "will allocate the FCM in the same manner that the underlying purchased power contract costs are allocated to energy and capacity. Currently 17% of purchased power costs are allocated to capacity." 2 Tr 81.

ABATE disputed the company's claim that the previous Commission-established FCM methodology is not appropriate for the FCM set forth in Act 235 because it will significantly increase surcharges and carrying charges. According to ABATE, "even if valid," these issues "do not justify revising the existing FCM collection approach." ABATE's reply brief, p. 2. In addition, ABATE asserted that Consumers' argument that the two FCMs are calculated differently is irrelevant. ABATE opined that:

> [w]hether or not the FCM for new renewable energy contracts is *calculated* differently from the current FCM makes no difference to the appropriateness of the current *collection method*. The FCM is still an incentive for entering into renewable energy contracts. A surcharge is therefore the most straightforward and transparent way of accounting for and collecting this "cost" to customers, which is unrelated to the actual power purchased through the renewable energy contract.

Id. (emphasis in original). Furthermore, ABATE reiterated that the company's proposed method for recovering FCM costs through the PSCR mechanism would reduce transparency and visibility regarding the REP and PPA costs that Consumers is collecting. ABATE contended that the volatility of uncertain projections and carrying charges for over- and undercollections are best addressed through a separate surcharge. *Id*.

The ALJ agreed with ABATE that "the FCM is still an incentive for entering into renewable energy contracts, and that a surcharge is the most straightforward and transparent way of accounting for and collecting this cost to customers, which is unrelated to the actual power purchased through the renewable energy contract." PFD, p. 99 (quoting ABATE's reply brief, p. 2). In addition, he found ABATE's argument persuasive that Consumers' proposed method for recovering FCM costs through the PSCR mechanism would provide less transparency for ratepayers. Therefore, the ALJ recommended that the Commission reject Consumers' proposal and require the company to recover FCM costs through a surcharge.

Consumers excepts, arguing that it is unclear from the ALJ's recommendation whether FCM costs should be recovered through the revenue recovery mechanism or the existing FCM surcharge. In any event, the company contends that both are improper. First, Consumers asserts that "recovery through the revenue recovery mechanism is inappropriate as one was not proposed in this case. No party objected to the Company's proposal not to implement such a mechanism. Nor did any party argue that it would be appropriate to delay recovery of the FCM." Consumers' exceptions, p. 8. Second, Consumers reiterates that it would not be appropriate to combine the new FCM with the existing FCM surcharge because the methodologies are different and it would lead to a significant increase in the surcharge based on uncertain projections and carrying charges for over- and undercollections. *See*, Consumers' exceptions, pp. 8-9 (citing 2 Tr 80-81). The company contends that "[t]he FCM is a cost of the renewable energy contract" and "[i]nclusion of this cost in the PSCR will ensure that it is recovered by the customers receiving the power." Consumers' exceptions, p. 9.

ABATE disagrees that the ALJ's recommendation was unclear. ABATE states that:

> the ALJ expressly identifies ABATE's recommendation to collect the FCM through the "existing FCM surcharge." The ALJ goes on to state that he "agrees with

> ABATE that the FCM is still an incentive for entering into renewable energy contracts, and that a surcharge is the most straightforward and transparent way of accounting for and collecting this cost to customers." He concludes by saying "this PFD recommends that the Commission should therefore reject Consumers' proposal and require that Consumers' FCM continue to be recovered through the surcharge."

ABATE's replies to exceptions, p. 2 (quoting the PFD, pp. 97, 99) (emphasis added by ABATE). ABATE contends that the only surcharge identified by the ALJ is the existing FCM surcharge and he recommended that FCM costs continue to be recovered through the surcharge.

ABATE also disputes Consumers' claim that the ALJ recommended that FCM costs be recovered in a revenue recovery mechanism—specifically the renewable energy surcharge. ABATE states that "[i]f Consumers' FCM were recovered in the renewable energy surcharge, then that would entirely defeat the reason behind the judge's recommendation. Specifically, the judge was persuaded that the FCM should be collected in a separate surcharge because it 'is the most straightforward and transparent way of accounting for and collecting this cost to customers.'" ABATE's replies to exceptions, pp. 2-3 (quoting the PFD, p. 99). According to ABATE, if the FCM were recovered through the renewable energy surcharge, there would be no transparency because the FCM cost would be comingled with other costs. Therefore, ABATE contends that the ALJ would not have recommended recovery of the FCM through the renewable energy surcharge.

Furthermore, ABATE disagrees with Consumers that if FCM costs are recovered separately from the renewable energy PPA cost, then the FCM will be an ICOC pursuant to Act 235 and should be recovered through the renewable energy surcharge. ABATE does not dispute that both the renewable energy PPA costs and associated FCM are costs that may be included in the ICOC calculation. However, ABATE asserts that "[i]f the Commission directs Consumers to recover the FCM in a FCM surcharge separate from the associated PPA costs, then there would still be no incremental costs of compliance for Consumers. The PPA costs would be offset by PSCR

revenues and the FCM costs would be offset by the FCM surcharge revenues." ABATE's replies to exceptions, p. 4. Thus, ABATE contends, there is no need for a renewable energy surcharge.

The Commission finds that the ALJ's recommendation should be adopted, in part. The Commission agrees with the ALJ that the terms of the settlement agreement approved by the June 23 order do not preclude Consumers from requesting recovery of FCM costs in this case. The settlement agreement in Case No. U-21090 was executed pursuant to the provisions of Act 341, under which an FCM was permitted, but approval was subject to the Commission's discretion. Act 235 was enacted after the settlement agreement was executed in Case No. U-21090 and after the June 23 order was issued, and Act 235 changed the statutory framework of Act 341. Act 235 expressly authorizes an FCM for rate-regulated providers and the eligibility of the rate-regulated provider to request an FCM is not subject to the Commission's discretion. In addition, as noted by the ALJ, "Consumers would not agree to the limited settlement FCM terms approved in the prior IRP cases today when all of the FCM terms under the revised statutes were available to it without any contest." PFD, p. 97. Therefore, the Commission agrees with the ALJ that the Attorney General's argument on this point should be rejected.

However, the Commission respectfully declines to adopt the ALJ's recommendation to approve ABATE's proposed recovery of the FCM costs through the FCM surcharge. ABATE contended that under the current FCM surcharge methodology, the capacity and energy components of the FCM are allocated using the 4 Coincident Peak 75/0/25 allocator and should continue to be allocated as such. As noted by Consumers, it appears that ABATE's recommended recovery method is based on the methodology established pursuant to the 2016 energy laws, rather than Act 235. Section 28(8) of Act 235 directs the Commission to authorize an FCM for a rate-regulated electric provider who enters into a PPA for renewable energy resources or a

third-party contract for an energy storage system or clean energy storage system with a utility that is not an affiliate for any contract entered after June 30, 2024. *See*, MCL 460.1028(8). Accordingly, the Commission finds persuasive Consumers' argument that "the FCM is a cost of the renewable energy contract" and, therefore, it should be recovered through the PSCR mechanism. 2 Tr 80. In addition, the Commission finds that ABATE failed to sufficiently rebut Consumers' argument that ABATE's proposed recovery of FCM costs through the current FCM surcharge would significantly increase the surcharge because of "uncertain projections and carrying charges for both over-collections and under-collections." 2 Tr 80.

10. Approval of Solar Contracts

Consumers noted that in Case No. U-21585, the company requested recovery of capital expenditures for the Mustang Mile, Washtenaw, Muskegon, and Spring Creek solar projects; however, after an agreement between the Staff and Consumers, the Commission approved removal of the capital expenditures from Case No. U-21585 and directed the company to seek recovery for the projects in Consumers' next REP case, which is the immediate case.

In this case, Consumers stated that the Mustang Mile Solar Project:

> is a 150 MW solar facility located in Macon Township, Lenawee County, Michigan. The project will be connected to the METC [Michigan Electric Transmission Company] 138 kV transmission system in accordance with the terms and conditions outlined in the MISO GIA, executed on August 6, 2020. All required land rights for the project have been secured and a special land use permit has been granted; however, legal challenges to the permit are currently being litigated which is preventing the completion of the project. While the Company expects that the opposition groups will ultimately fail in their legal challenge, the project has been delayed because of these challenges [and] therefore a revision to the original project schedule is required. The unpredictable duration of the legal issues makes it difficult to assume an accurate revised COD at this time.

2 Tr 224-225. The company asserted that it is working with Invenergy on a revised schedule and cost for the project, which will be presented to the Commission for approval. 2 Tr 225.

The company explained that the Washtenaw Solar Project:

> is a 150 MW solar facility located in Saline Township, Washtenaw County, Michigan. The project will be interconnected with the International Transmission Company's 345 kV transmission system in accordance with the terms and conditions outlined in its MISO GIA, executed April 23, 2021. The project has secured land rights for more than 1,100 acres, but due to changes to Saline Township zoning ordinances enacted after the execution of the BTA, the project will require additional land rights in order to be sited locally or will need to rely on the recently passed state certification process.

2 Tr 223-224. The company asserted that it is working with Invenergy on a revised schedule and cost for the project, which will be presented to the Commission for approval.

The Attorney General objected to including costs for the Mustang Mile and Washtenaw solar projects in the company's REP. She explained that both projects "currently do not have expected commercial operation dates due to significant delays these projects have experienced related to ligation and regulatory delays in obtaining permits needed to commence construction." 2 Tr 453. Specifically, the Attorney General noted that in Consumers' electric rate case, the company could not provide an accurate COD for Mustang Mile and conceded that Washtenaw would not be in operation until late 2027. In addition, she stated that in discovery in this case, Consumers could not provide an update on the status of the Washtenaw project. The Attorney General contended that "[t]hese projects can be included in future amended RE Plans once greater certainty is known regarding the viability of these projects and anticipated COD." 2 Tr 456. Furthermore, she recommended that the Commission direct the company to identify replacement RECs for these projects until plans for the projects are more concrete.

Consumers disagreed with the Attorney General, asserting that it is required to include in its REP: (1) "a forecast of the renewable energy resources needed to comply with the renewable energy credit standard pursuant to a filing schedule established by the commission," (2) a "mechanism for the recovery of the incremental costs of compliance," and (3) costs associated

with the "renewable energy portfolio established to achieve compliance with the renewable energy standards." Consumers' initial brief, p. 55 (quoting MCL 460.1022(2) and (3); MCL 460.1047(2)(a)(i)). Accordingly, the company stated that it included the Mustang Mile and the Washtenaw solar projects in its REP as renewable energy resources that comply with the RPS.

Consumers noted that the Mustang Mile and Washtenaw BTA were both approved in Case No. U-20165, and although there is some uncertainty with the COD for the projects, both "are the result of competitive solicitations that were conducted pursuant to a Commission-approved IRP." Consumers' initial brief, p. 55 (citing 2 Tr 229). In addition, the company contended that by including the projects in the REP, it is acknowledging that the projects will be used as resources to meet the RPS and that the costs will flow through to the REP reconciliation case. In Consumers' opinion, "[t]he uncertainty of the COD has no bearing on the appropriateness of including the projects within this RE Plan. All renewable energy projects face schedule risk, and these two specific projects have realized that risk." 2 Tr 229.

Furthermore, the company argued that there is no present cost to customers by including the Mustang Mile and the Washtenaw solar projects in the REP. By contrast, Consumers stated, the REP would be significantly more inaccurate if the Mustang Mile and Washtenaw solar projects are excluded, asserting that "[b]oth the costs of compliance and PSCR transfer costs would be dramatically under-projected as a result of excluding these in-development projects." 2 Tr 193.

The ALJ agreed with the Attorney General that the Mustang Mile and Washtenaw solar projects should be excluded from the REP. He noted that "Consumers acknowledges the delays and uncertainty associated with these two projects and while it believes that the challenges to these projects will be resolved favorably, any such resolutions are unclear at this time." PFD, p. 104. Therefore, the ALJ recommended that the Commission exclude from the REP the costs for the

Mustang Mile and Washtenaw solar projects and direct the company to identify replacement RECs for the projects.

Consumers objects to the ALJ's recommendation, explaining that:

> [i]f the projected costs for Mustang Mile and Washtenaw are excluded from the Amended RE Plan, then the projected cost of compliance would be incomplete, which would then make the Company's regulatory balance projections inaccurate. The Company's plan will also be insufficient to achieve compliance with the REC Standard. Removal of these projects from the Amended RE Plan would result in under-projecting the costs of compliance and the PSCR transfer costs. Eliminating these projects, and their development costs, from the Amended RE Plan would create significant inaccuracies and variances between the Amended RE Plan and the annual reconciliations.

Consumers' exceptions, pp. 12-13 (citing 2 Tr 192-193, 195). In addition, the company disagrees with the ALJ's recommendation that Consumers identify replacement RECs for the Mustang Mile and Washtenaw solar projects. Consumers argues that "neither the PFD, nor any parties in this case, identified any more certain projects that the Company could substitute for the Mustang Mile and Washtenaw projects in this Amended RE Plan." Consumers' exceptions, p. 13. Finally, the company reiterates that there is no current customer rate impact for including the Mustang Mile and Washtenaw solar projects in the amended REP.

The Staff excepts, asserting that the Mustang Mile and Washtenaw solar projects should be included in the REP and that Consumers is entitled to cost recovery for the projects. The Staff states that the Commission has already approved these projects in Case No. U-20165 and "[i]n its March 2025 Order in Case No. U-21585, the Commission also agreed that [it] was reasonable for the Company to move these projects from the Company's general rate case to its Amended REP." Staff's exceptions, p. 2 (citing March 21, 2025 order in Case No. U-21585, p. 158). The Staff contends that if Consumers is required to identify additional RECs and the Mustang Mile and

Washtenaw projects then progress, the company will have procured unnecessary RECs and superfluous expense. *Id*., pp. 2-3.

In exceptions, GLREA notes that the Attorney General recommended that the Mustang Mile and Washtenaw solar projects be removed from the company's REP and that the Commission direct Consumers to identify replacement RECs for these projects. GLREA "proposes the use of DG outflow REC purchases as a readily available source of replacement RECs." GLREA's exceptions, p. 19.

The Attorney General disagrees with Consumers' claim that because the projects have been included in the REP, the projects are necessary to the plan. She states that the company disregards the standard in Act 235 that requires the Commission to evaluate whether the REP and the proposed costs are reasonable and prudent. The Attorney General asserts that "[g]iven this standard of review, the Company has failed to meet its burden of proof to show that inclusion of the Washtenaw and Mustang Mile projects in its RE Plan is reasonable and prudent. The preponderance of the evidence presented in this case highlights the uncertainty as to whether and when the two solar projects might actually be completed." Attorney General's replies to exceptions, p. 2 (footnote omitted).

The Attorney General also objects to the Staff argument that because the Mustang Mile and Washtenaw solar projects were included in Consumers' IRP, the cost of the projects may be recovered through the REP process. She states that the "Staff presents no authority to justify this conclusion, and nothing in the Commission's Order in Case U-21585 guaranteed cost recovery as part of this case. In fact, ***as noted in the Case U-21585 Order, Consumers explicitly addressed the possibility that it might not achieve recovery in this REP case, thus directly contradicting***

Staff's argument here . . . ." Attorney General's replies to exceptions, pp. 5-6 (emphasis in original).

The Commission finds persuasive Consumers' and the Staff's arguments that the Mustang Mile and Washtenaw solar projects should be included in the company's REP. As noted by Consumers and the Staff, the Commission approved the BTAs for these projects in Case No. U-20165, the Commission agreed that cost recovery for these projects should be removed from Case No. U-21585, and the Commission agreed in Case No. U-21585 that Consumers could include the projects in the immediate case. Additionally, the Commission finds persuasive Consumers' argument that if the two projects are excluded from the company's amended REP, "the costs of compliance and PSCR transfer costs would be dramatically under-projected" and Consumers' amended REP "will also be insufficient to achieve compliance with the REC Standard." 2 Tr 193; Consumers' exceptions, p. 12. Furthermore, the Commission agrees with Consumers and the Staff that if the projects are excluded and the company is directed to identify replacement RECs to comply with the RPS, no party has identified any more certain and/or less costly replacement projects. And, as noted by the Staff, if Consumers is directed to procure replacement RECs and the Mustang Mile and Washtenaw solar projects then move forward, the company will have procured needless RECs and additional unnecessary expense. Therefore, the Commission declines to adopt the ALJ's recommendation to approve the Attorney General's proposed exclusion of the projects from the company's amended REP and, instead, approves Consumers' request to include recovery of capital expenditures for these projects in this case.

11. Other Issues

a. Biomass Merchant Plant Resources

The BMPs asserted that Consumers' amended REP has serious flaws and does not comply with the requirements of MCL 460.1001, *et seq*., and the Commission's Filing Requirements for Renewable Energy Plans. The BMPs explained that the company's:

> [a]mended REP includes only intermittent, non-dispatchable solar generation with an assumed capacity factor of 23% and wind generation with a capacity factor of 29.0%. The assumed solar capacity factor of 23% is overstated and unsupported. Consumers' own generation data shows that the historic average capacity factors of its existing solar projects range between 18.1% and 21.2%. That virtually ensures that Consumers actual costs for the 8,000 MW of additional solar generation for which it has requested *Ex Parte* contract approval will exceed its stated Levelized Cost of Energy ("LCOE").

BMPs' initial brief, p. 1 (citing 2 Tr 60, 265; Exhibits BMP-5 and BMP-14). Further, the BMPs stated that if the company uses the 23% solar capacity factor, Consumers will be short 1.98 million RECs in 2040, resulting in only 55% compliance compared to the required 60%. The BMPs argued that, instead, Consumers' amended REP should include a mix of existing, indigenous Michigan renewable energy resources and non-intermittent, baseload dispatchable renewable generation that can be provided by the BMPs.

The BMPs stated that their baseload, continuous dispatchable energy can be provided 24/7, with an annual proven 93.0% availability factor and 100% capacity factor. More specifically, the BMPs contended that they:

> can provide this performance at costs equivalent or lower than any LCOE associated with combinations of renewable energy generation resource and energy storage combination Consumers has included in its Amended REP. ***The 183.17 MW of BMPs can replace 692 MW of solar capacity even using Consumers' overstated 23.0% solar capacity factor. They can replace approximately 776.4 MW of solar generation using the actual 20.5% solar capacity factor of Consumers existing solar facilities.*** In fact, no reasonable combination of renewable generation resources and energy storage proposed by Consumers in the Amended REP can provide the same 24/7 generation performance as the BMPs.

2 Tr 265 (emphasis in original). The BMPs also asserted that "Consumers has not entered into any discussions with the BMPs about the possibility of including their generation in the Amended REP beyond their current contract expiration dates," which the BMPs claim is contrary to the provisions of MCL 460.1001(2). 2 Tr 264 (citing Exhibit BMP-4).

Furthermore, the BMPs disputed the company's calculation of the solar LCOE of $70.31/MWh. According to the BMPs, "[t]he calculation of the LCOE value was performed over a 35 year period, which is longer than the 30 year life of the solar project. Correcting the solar LCOE calculation to only account for a 30 year period increases the LCOE to $72.23/MWh." 2 Tr 291 (citing Exhibit BMP-7). Additionally, the BMPs argued that Consumers incorrectly used a 23% solar capacity factor rather than a realistic 20.5% average capacity factor calculated by the BMPs. The BMPs stated that use of the correct 20.5% average capacity factor increases the solar LCOE to $84.36/MWh. *See*, 2 Tr 291-292 (citing Exhibit BMP-7). The BMPs opined that if the company's proposed solar capacity is replaced with BMP capacity, it could reduce the cost of Consumers' amended REP by $3.5 billion. 2 Tr 265. If Consumers' calculations for wind LCOE are correct, the BMPs asserted that the cost of the REP would be reduced by $2.3 billion over the wind project's lifetime by replacing wind capacity with BMP capacity. 2 Tr 290. Moreover, if the solar LCOE were to increase by 40%, the BMPs stated that:

> the solar LCOE would be $126.95/MWh and the wind LCOE would be $77.62/MWH. Adding energy storage at 140% of the $143.54/MWh LCOE, to the solar LCOE, would raise solar LCOE to $154.59/MWh Consumers' ratepayer cost reduction of replacing solar with the BMPS, would be $5.3 billion for solar and $3.2 billion for wind generation over the 30 year life of the generation resource.

2 Tr 290.

In conclusion, the BMPs asserted that Consumers' amended REP should be rejected because the solar LCOE was calculated incorrectly, the company failed to consider the BMPs as a viable

renewable energy resource for the REP, the miscalculation of the solar capacity factor results in a shortfall of RECs, the costs of the amended REP were not sufficiently supported, and the Commission will not be able to adequately contain costs. To ensure that biomass generation is included in the amended REP, the BMPs stated that:

> [i]t is important that the RFP evaluation criteria used to determine successful bidders include all the beneficial traits of the BMPS, including the following:
>
> 1. Dispatchable generation that can produce power on a 24/7 basis throughout the year.
> 2. Historic reliability with availability in excess of 90%.
> 3. Does not require energy storage backup like solar, to provide energy during evening hours and winter periods.
> 4. Is not likely to cause negative MISO prices.
> 5. Can provide synchronous generation that supports grid stability.
> 6. Does not degrade over time like solar generation.
> 7. It has a longer operating life than solar energy and battery storage.
> 8. Creates long term Michigan jobs.

2 Tr 299.

Consumers disagreed with the BMPs' claim that the company has assumed a 23% solar capacity factor that is unrealistic. The company asserted that it:

> does not have enough utility-scale solar projects in its portfolio to state that the assumed 23% capacity factor is not realistic. The Company utilized the same solar capacity factor that was utilized in its 2021 Integrated Resource Plan ("IRP"), Case No. U-21090, due to the fact that the Company has not developed/acquired a substantial amount of utility-scale solar that is online and producing enough data to change this value.

2 Tr 349. Consumers stated that it would review any assumptions or changes to the solar capacity factor in its next IRP. The company noted that "the Commission has indicated that 'IRPs remain the most appropriate venue to consider generation diversity as well as renewable resource planning because IRPs allow for the full assessment of renewable resources against other resources . . . .'" Consumers' reply brief, p. 12 (quoting the April 25, 2024 order in Case No. U-21568 (April 25 order) p. 19).

In addition, Consumers disputed the BMPs' conclusion that the company's own generation data shows that the historical capacity factors for Consumers' existing solar projects is between 17.4% and 19.4%, as set forth in Exhibit BMP-5. The company contended that Exhibit BMP-5 contains many errors, including the incorrect capacity for two projects (the remaining projects represent aggregated capacities), and one of the projects did not meet its COD until part way through the year and, therefore, the exhibit does not support the BMPs' argument on this issue. *See*, 2 Tr 349-350.

The company stated that Exhibit A-40 provides data for company-owned or contracted solar facilities 5 MW or larger that were in operation for the entirety of 2024. Consumers noted that these facilities "had capacity factors above the 19.4% that [BMPs' witness] Mr. Polich recommends as the upper bound. In fact, only one of these facilities had a capacity factor that was below 19.4% in 2024 (Willford Solar – 19.34%, 20 MW)." 2 Tr 350-351. However, the company asserted that Exhibit A-40 does not provide enough data to support changes to Consumers' long-term solar capacity factor assumption. More specifically, the company stated that "Exhibit A-40 (ZSC-10) provides solar generation data for a single year. Long-term forecasting should not be based on a single year's generation values since solar production can vary year to year. Additionally, the dataset is relatively small, containing only 530 MW, in comparison to the total amount of solar included in this amended Renewable Energy Plan." 2 Tr 351. Thus, Consumers argued that there is insufficient information in this case to adjust the assumed solar capacity factor as requested by the BMPs.

Next, Consumers disagreed with the BMPs that the company's LCOE of $70.31/MWh is incorrect. The company acknowledges that there was an error in its testimony, claiming that the life cycle for solar projects is 30 years. Consumers asserted that it "intended to file this amended

Renewable Energy Plan assuming a solar useful life of 35 years. The 35-year useful life of solar aligns with assumptions used in recent Company request for proposals ("RFPs") for solar resources." 2 Tr 352.

In addition, the company disputed the BMPs' claim that if Consumers' LCOE of $70.31/MWh is correct, the company could reduce the cost of the REP by over $100 million annually and by more than $3 billion over the lifetime of the solar project by replacing 692 MW of solar with biomass generation. Consumers stated that:

> [t]hese values should not be taken as potential cost savings by including the BMPs in this amended Renewable Energy Plan. These values simply represent the cost of solar needed to produce the aggregated BMPs equivalent amount of renewable energy credits ("RECs"). That is to say that the annual economic benefit was calculated using the BMPs stated amount of annual BMP RECs (1,394,193) multiplied by the corrected solar LCOE of $72.23/MWh. The Life Cycle value on line 11 [of Exhibit A-41] was calculated as the annual value (line 10) multiplied by the BMPs' assumed 30-[year] life of solar energy resources. Additionally, the solar LCOE used in these calculations does not align with the Company's solar LCOE assumption of $70.31/MWh. Regardless of which solar LCOE was used in these calculations, the calculation logic is flawed because these calculations fail to consider any costs associated with the BMPs' contracts. These calculations provide an estimated cost of the 1,394,193 RECs if they were produced by solar facilities but do not provide the equivalent estimated cost of these RECs if they were produced by the BMPs.

2 Tr 353. Consumers asserted that the same flawed logic was applied by the BMPs when claiming that cost savings could be garnered by using the BMPs' calculated LCOE. In conclusion, the company averred that there would be no cost savings by using the BMPs' calculation methodology. *See*, 2 Tr 354-355.

The BMPs disputed Consumers' claim that the company intended to include a 35-year useful life for solar facilities in this case. The BMPs noted that on numerous occasions, the company stated that the useful life is 30 years, including in Consumers' 2021 IRP settlement, in testimony in the immediate case, and in a discovery response in this case. The BMPs asserted that the company

has provided no evidence to support the claim that solar facilities have a 35-year useful life and had ample time to update the record in this case. *See*, 2 Tr 311.

Furthermore, regarding the claim that the company's historical solar data should not impact the solar capacity factor, the BMPs asserted that, according to Consumers, "historical data does not matter, and the Commission should simply 'accept' Consumers assumed solar capacity factor of 23% regardless of evidence to the contrary." 2 Tr 311. The BMPs reiterated that Exhibits A-40 and BMP-14 demonstrate that the company's average solar capacity factor for 2021-2024 is below 23%. The BMPs contended that Consumers has not, and cannot, support the proposed 23% solar capacity factor and recommended that the Commission direct the company to include a more reasonable factor in the amended REP.

The BMPs disagreed that the company's solar capacity factor should be reviewed in Consumers' next IRP rather than the immediate amended REP case. The BMPs stated that:

> Consumers ignores the facts that both Act 235 of 2023 and the Commission's Filing Requirements for Renewable Energy Plans post-date the Company's 2021 Integrated Resource Plan proceeding, Case No. U-21090, by more than 2 years. That proceeding was an Integrated Resource Plan ("IRP") proceeding. This proceeding is a Renewable Energy Plan case. It defies logic to conclude that this Renewable Energy Plan should accept the 23% solar capacity factor from its 2021 IRP when (i) neither Act 235's statutory requirements nor the Commission's Filing Requirements for Renewable Energy Plans existed in 2021, (ii) the correct solar capacity factor data are directly relevant to the question of whether Consumers' Amended REP satisfies the requirements of Act 235 and the Commission's Filing Requirements, and (iii) substantial solar capacity factor data is now available that was not available in 2021.

BMPs' reply brief, pp. 1-2.

Finally, the BMPs stated that although they "have the opportunity to bid into [the company's] All Sources Energy Generation Projects RFP," the "2025 All Resources Generation RFP [does not] provide the opportunity for BMPs to bid into renewable energy generation resources." 2 Tr 315. The BMPs explained that in the draft 2025 All Sources RFP, there are three "tranches"

of "clean resources" but that the definition of "clean energy" in the 2025 All Sources RFP would exclude biomass generation. 2 Tr 316.

The ALJ found the BMPs' arguments unpersuasive. He noted that "the Commission has determined that IRPs are the most appropriate venue for considering generation diversity and renewable resource planning, and 'amended REPs should reflect the assumptions included in the providers' most recently approved IRP.'" PFD, p. 116 (quoting the April 25 order, p. 19). The ALJ opined that it is reasonable to expect that the first REP amendment after the enactment Act 235 may not align with the utility's IRP if that IRP was approved before the enactment of Act 235. However, he stated that that is not the case here. Rather, the ALJ found that:

> Consumers incorporates the same 23% solar capacity factor that it used in its most recent IRP (Case No. U-21090), and this PFD finds that factor to be reasonable. Consumers has shown that the data on actual solar performance is too limited to warrant an adjustment to the solar capacity factor at this time. It has also established that the BMPs rely on flawed data to support their argument. Issues involving solar or wind capacity are essential to the modeling that is done in IRP proceedings. Therefore, Consumers' solar capacity factor should be assessed in its next IRP, with the benefit of additional data.

PFD, p. 116 (citing 2 Tr 349-351).

The ALJ also recommended approval of Consumers' forecasted solar LCOE. He found that "the BMPs rely on an erroneous capacity factor to support a higher LCOE. In addition, this PFD is not convinced that Consumers' 35-year solar lifecycle assumption used to calculate the LCOE is unreasonable." PFD, pp. 116-117 (citing Consumers' initial brief, p. 59). Furthermore, the ALJ agreed with Consumers that the BMPs' cost savings calculation that substitutes biomass generation for solar fails to account for the cost of the BMP contracts and is, therefore, flawed and should be rejected.

Finally, the ALJ found the BMPs' claim unpersuasive that they have been excluded from the RFP process. He stated that although "several of the BMPs are still under contract with

Consumers and were therefore excluded from bidding in the 2025 All Resources Generation RFP, . . . [t]his does not establish that the RFP process is somehow flawed or that those BMPs currently under contract will be unable to participate in future RFPs." PFD, p. 117.

In exceptions, the BMPs reiterate the arguments set forth in testimony and briefing, requesting that the Commission direct Consumers to revise its amended REP to reflect a realistic solar capacity factor, to correct its contradictory position regarding the useful life of solar resources, to calculate the LCOE using the BMPs' data, and to replace some solar and wind generation in the company's REP with biomass generation. *See*, BMPs' exceptions, pp. 7-27.

Consumers replies, stating that "[t]he PFD very thoughtfully and thoroughly addressed the arguments raised by the Biomass Merchant Plants . . . . For the reasons previously stated in the Company's Initial and Reply Briefs, [the BMPs'] arguments are erroneous. The Company asks that the Commission adopt the PFD's findings . . . ." Consumers' replies to exceptions, pp. 15-16.

The Commission finds that the ALJ's recommendation is reasonable and prudent and should be adopted. The Commission agrees with the ALJ that Consumers' IRP is the most appropriate venue to consider generation diversity and renewable energy resource planning. In addition, the Commission notes that the company's proposed 23% solar capacity factor was established in Consumers' most recent IRP and finds that it was appropriately included in this amended REP. The Commission agrees with the ALJ that "Consumers has shown that the data on actual solar performance is too limited to warrant an adjustment to the solar capacity factor at this time" but that it should be reviewed in the company's next IRP when there is additional data. PFD, p. 116. The Commission also finds persuasive Consumers' argument that the BMPs relied on erroneous data to demonstrate that the company's LCOE is incorrect. Moreover, the Commission agrees with Consumers and the ALJ that the BMPs' "cost-savings calculations are flawed because they

fail to account for the costs associated with BMP contracts and incorrectly assume BMPs can replace solar capacity on a one-to-one basis." *Id*., p. 113.

Finally, the Commission finds the BMPs' claim that they have been deliberately excluded from Consumers' RFP process to be unpersuasive. The BMPs stated that Consumers' amended REP does not include any biomass generation. In addition, the BMPs noted that "they are not 'clean energy' because they emit CO2 and are, therefore, excluded from all but one of that solicitations' Tranches" and that several BMPs are "under contract with Consumers, which excludes them from bidding." BMPs' initial brief, pp. 23-24. The Commission finds that the circumstances cited by the BMPs are not evidence that Consumers has "gone out of its way to exclude the BMPs from its Amended REP" or that the RFP process is flawed. *Id*., p. 23. As noted by the ALJ, once the BMPs are no longer under contract with Consumers, they "will be [able] to participate in future RFPs." PFD, p. 117.

b. Length of Renewable Energy Plan

The Staff stated that Act 295, as amended by Act 342, established a 20-year renewable energy plan period with a finite conclusion in 2029. However, the Staff asserted that it is unclear whether Act 235 established a finite conclusion for amended REPs. The Staff noted that Consumers "understands that the Amended RE Plan will be for a rolling 20 year period." Exhibit S-1, p. 15. The Staff contended that, for simplicity, it prefers a fixed 20-year period because it establishes a fixed period for levelization of the ICOC, rather than a new levelization for each amended REP. In addition, the Staff stated that the fixed period "would help to encourage a regulatory balance that is as near to zero as possible in the out years (it should be noted that a $200 million regulatory asset or liability is roughly equal to a single 100 MW utility scale solar facility)." 4 Tr 800. Therefore, the Staff requested that the Commission clarify whether the amended REP planning

period ends in 20 years or, as Consumers states, is a rolling 20-year period. According to the Staff, this clarification is important because it "is necessary to calculate the levelized ICOC recovery as established in MCL 460.1045(3) for all future AREPs [amended REPs] filed biennially and any potential adjustments in [reconciliations]." 4 Tr 800. The Staff acknowledged that to make a determination as to whether a 20-year finite plan period or a 20-year rolling period is required, the Commission does not have to decide how to manage the ICOC regulatory balance. The Staff contended that "it would recommend modifications in annual [reconciliations] and biennial AREPs to ensure that the regulatory liability remains relatively neutral in the future, as supported within Company witness Johnston's testimony and discovery response." 4 Tr 800.

Consumers stated that it interprets Act 235 as establishing a 20-year rolling period for amended REP filings. According to the company:

> Act 235's amendment of Act 295 removed several references regarding the expiration and conclusion of the 20-year RE Plan period. Instead, under Act 235, Consumers Energy will file an amended RE Plan within two years after an order approving the last amended RE Plan, and each amended RE Plan will include a calculation of the [ICOC] "for a 20-year period beginning with approval of the amended renewable energy plan." Thus, each amended RE Plan filing will include an updated 20-year plan period for calculating the [ICOC].

Consumers' initial brief, p. 61 (citing 2 Tr 797-799; MCL 460.1022(3) and 460.1045). Consumers asserted that in these filings, the company will be able to make adjustments to minimize the liability balance, including possibly reducing the transfer price and implementing a credit surcharge.

The ALJ disagreed with the Staff that clarification is needed in this case. He noted that the:

> Staff acknowledges that it will recommend modifications in annual reconciliations and biennial Amended REPs to ensure that the regulatory liability remains relatively neutral in the future. Moreover, any such clarification will involve application of statutory construction principles to the various versions of the statutory sections which were comprehensively amended, and in this case, no party

> other than Staff provided any testimony on how these amended provisions should be interpreted.

PFD, pp. 119-120. The ALJ recommended that the Commission decline to make a determination in this case until other parties have provided testimony in a subsequent case.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation to be reasonable and prudent and that it should be adopted.

c. Renewable Energy Plan Statutory Timeline and Contract Approval

GLREA asserted that there are many issues with Consumers' amended REP and, therefore, the Commission should only "look at only 1 or two years of the plan and decide if the first year or two is appropriate and ask for the REP to be reworked for submittal next year or the following year[;] by then some of the important federal budget issues and other department changes should be clarified by then." 4 Tr 613. In GLREA's opinion, the revised amended REP would be more reasonable and would include recommendations provided in the intervenors' testimony.

In addition, GLREA recommended that REP costs associated should be recovered through a rate case. GLREA argued that "[REP] cases should only reflect the plans and determine if the plans are reasonable and prudent but are not a place for cost recovery, especially for very long-term investments like those proposed in this REP, especially during very volatile economic times." 4 Tr 613-614. Furthermore, GLREA contended that if the Commission approves cost recovery in the REP, the Commission will be approving the proposed prices as recoverable when the costs were meant to be estimates, not actual costs.

Consumers objected to GLREA's request that the Commission only review one or two years of the company's REP and direct Consumers to revise the plan. The company stated that it:

> is required, pursuant to statute, to calculate the incremental cost of compliance for a 20-year period. This amended RE Plan carefully and thoughtfully lays out the Company's current plan to achieve the REC standard through 2045. MCL 460.1022(3) requires the Commission to then approve, the amended RE Plan with any changes consented to by the Company or reject the amended RE Plan. Reviewing and approving only one or two years of the Company's amended RE Plan is not a viable option.

2 Tr 119. In addition, Consumers noted that because it is required to file another amended REP in two years to demonstrate compliance with the RPS, this requirement may assuage GLREA's concerns.

In response to GLREA's claim that REP cost recovery should be in a rate case, the company asserted that, as in the past, "the costs for complying with the REC standard have been and will continue to be presented in renewable energy plans and have been and will continue to be reconciled annually in renewable cost reconciliation cases. While Act 235 has added an option for recovery of the incremental cost of compliance in base electric rates, the Company has chosen not to pursue this option." 2 Tr 119-120.

Moreover, Consumers averred that Commission approval of the amended REP is not definite approval for REP cost recovery. Rather, the company stated that Commission approval in this case:

> is approving the Company's plans for the addition of renewable energy resources and the projected costs associated with the Company's plan. Projects that are developed and whose levelized costs are below the LCOE thresholds will still require Commission approval, but that approval can be provided on an ex parte basis. Projects whose levelized costs are not below the LCOE thresholds are required to be filed for approval but will require a contested case proceeding prior to Commission approval.

2 Tr 120. Consumers reiterated that after the costs are incurred, the company will file an annual renewable cost reconciliation in a contested case wherein Consumers must present actual costs for review and approval.

The ALJ found GLREA's requests to be contrary to Act 235 and unsupported. He also "agree[d] with Consumers that GLREA's assertions regarding cost recovery are misguided and are in direct conflict with REP cost recovery processes." PFD, p. 122. Therefore, he recommended that GLREA's concerns and suggestions be rejected.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation to be reasonable and prudent and that it should be adopted.

THEREFORE, IT IS ORDERED that:

A. Consumers Energy Company's renewable energy plan is approved, in part, as described in this order.

B. Consumers Energy Company's proposed incentive renewable energy credits, as calculated using the "peak demand hours" set forth in the December 4, 2008 temporary order in Case No. U-15800, are approved for 2023. However, until the Commission determines whether any adjustments should be made to how incentive renewable energy credits are calculated, the Commission declines to approve the company's incentive renewable energy credits for 2024-2045.

C. Consumers Energy Company shall accelerate its acquisition of new wind resources, as set forth in this order, which may include actively soliciting power purchase agreements for wind generation outside of Midcontinent Independent System Operator, Inc., Zone 7.

D. For Consumers Energy Company's 140% levelized cost of energy multiplier, in future plans, the upper cost limit in the company's renewable energy plan shall be tied to the upper cost limit included in the company's most recently approved integrated resource plan and vice versa.

E. In Consumers Energy Company's next integrated resource plan, the company shall evaluate various load growth scenarios, including storage and curtailment.

F. Consumers Energy Company shall implement a competitive bidding process for wind and energy storage resources, shall actively solicit third-party power purchase agreements in all its future requests for proposals, and shall use an independent administrator in its competitive bidding process, as described in this order.

G. Consumers Energy Company shall include the withdrawal of cost recovery for co-located energy storage projects in subsequent biannual amended REP filings and its 2025 REP reconciliation.

H. Within 14 days of this order, Consumers Energy Company shall file a statement in this docket that it consents to the changes to its renewable energy plan as contained in this order, pursuant to MCL 460.1022(3). Failure to submit such statement within the 14-day time period shall void the Commission's approval of the company's renewable energy plan. If Consumers Energy Company does not consent to the changes to its renewable energy plan as set out in this order, the company shall file a revised renewable energy plan in this docket no later than January 12, 2026.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at LARA-MPSC-Edockets@michigan.gov and to the Michigan Department of Attorney General - Public Service Division at sheac1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

_____
Daniel C. Scripps, Chair

_____
Katherine L. Peretick, Commissioner

_____
Shaquila Myers, Commissioner

By its action of September 11, 2025.

_____
Lisa Felice, Executive Secretary

P R O O F O F S E R V I C E

STATE OF MICHIGAN)

Case No. U-21816

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on September 11, 2025 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna Brown

Subscribed and sworn to before me
this 11th day of September 2025.

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2030

Service List for Case: U-21816

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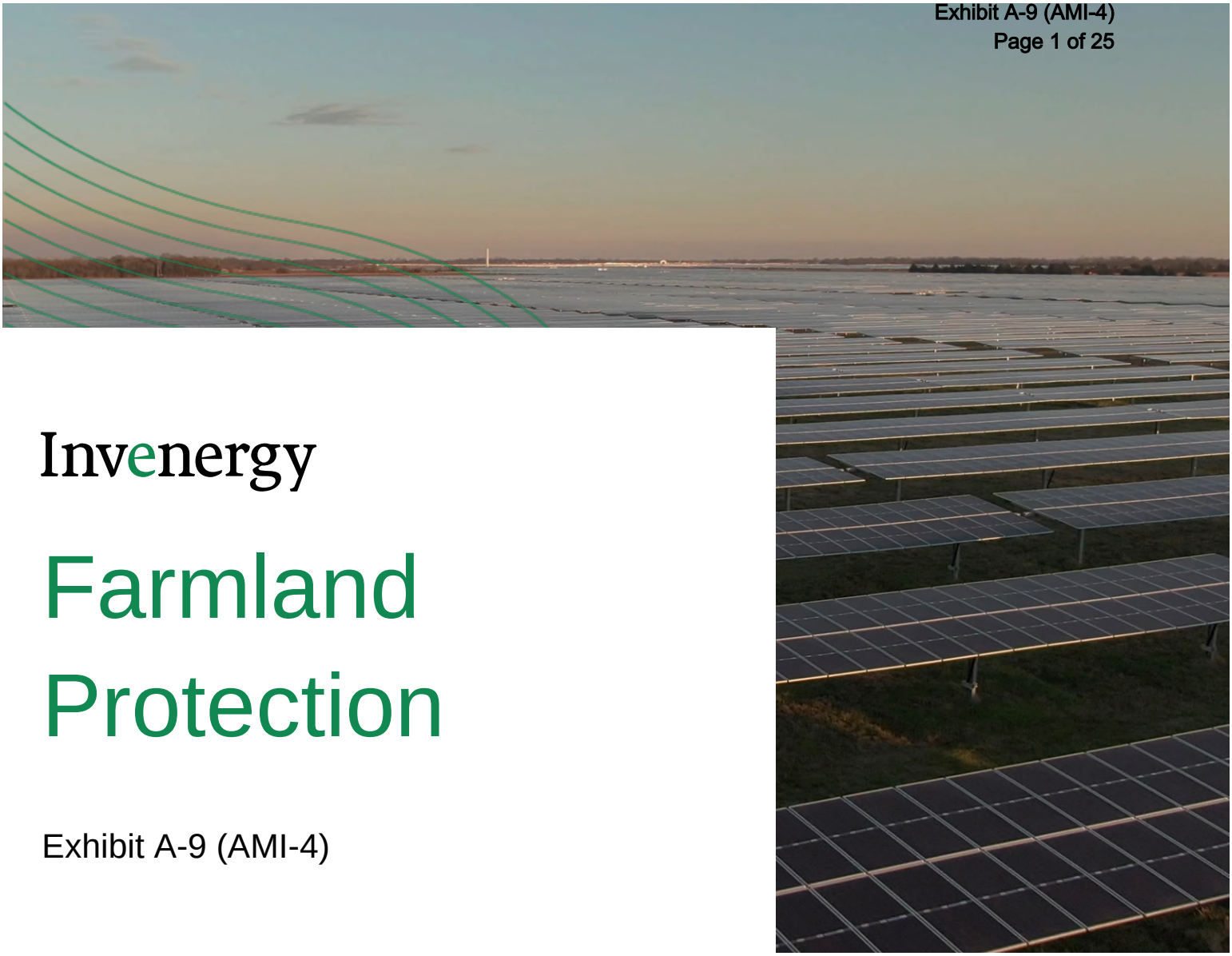

Invenergy

Farmland Protection

Exhibit A-9 (AMI-4)

PREPARED FOR:

WASHTENAW SOLAR ENERGY LLC

Invenergy

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APPENDIX A: FARMLAND PROTECTION 5

1.0 Farmland

1.1 Introduction

Washtenaw Solar Energy LLC ("Washtenaw Solar") is proposing a 150 MW solar energy facility in Saline Township, Washtenaw County, Michigan (the "Project"). The Project is located primarily on cleared agricultural lands. With the exception of the substation parcel, the land for the Project is leased. Upon decommissioning, it is anticipated that the land on which the Project is situated will be used once again for agricultural purposes. Washtenaw Solar has reviewed the Project's use of farmland to ensure that the Project will not unreasonably diminish farmland. Additionally, Washtenaw Solar has determined how it anticipates returning the Project to farmable conditions. Washtenaw Solar consulted with Environmental Consulting & Technology, Inc. ("ECT") to analyze and develop the attached report on Farmland Protection. See **Appendix A**.

1.2 Farmland Used by the Project

Washtenaw Solar has analyzed each parcel that would host Project facilities (the "Project Area") as well as the surrounding 1,000 feet (the "Study Area"). Both the Project Area and the Study Area consist primarily of prime farmland, prime farmland (if drained), and farmland of local importance, as the United States Department of Agriculture defines those terms. However, the proportion of these lands used by the Project is generally consistent with proportion of such lands in Saline Township. The amount of farmland disturbed by the Project will be smaller than the Project Area and is anticipated to be 1,407 acres. The anticipated limits of disturbance for the Project are identified in **Exhibit A-1.1 (KAP-1)**.

To analyze the impact of the Project on farmland, Washtenaw Solar examined the following on both the township and county level:

- Type of farmland the Project will use (*i.e.*, Standard, Prime, Specialty Crops, etc.).
- Total acreage of farmland the Project will use.
- Farmland utilized by the Project as a percentage of farmland in the Township and County.
- Current percentage of land within the Township and County considered farmland, differentiated by type.
- Total acreage of farmland within the Township and the County, differentiated by type.

1.3 Farmland Protection

Washtenaw Solar, as well as many participating landowners, have taken measures to reduce and minimize the impacts to agriculture. Most landowners own additional agricultural lands that will not be utilized for the Project, leasing only a portion of their lands. Lands in the Project Area that are not within the limits of disturbance will mainly remain agricultural in use. Washtenaw Solar's use of contiguous powerblocks is also more efficient and leads to less disruption of agricultural lands overall. Finally, Washtenaw Solar has established a vegetation and soil management strategy that will improve soil health over time and have a positive impact when the land is returned to its agricultural use.

1.4 Conclusion

The use of agricultural lands for the Project limits the Project's anticipated impact on the environment and natural resources. Agricultural lands are prevalent in both Saline Township and Washtenaw County. The Project is not anticipated to unreasonably diminish farmland during the Project or thereafter.

Appendix

Invenergy

2.0 Appendix

Appendix A: Farmland Protection

Exhibit A-9 - Farmland Protection, Washtenaw Solar Energy Project, Washtenaw County, Michigan

September 2025

Prepared for:

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List of Acronyms and Abbreviations

BMP(s): Best Management Practice(s)

ECT: Environmental Consulting & Technology, Inc.

GIS: Geographic Information Systems

LOD: Limits of Disturbance

MPSC: Michigan Public Service Commission

NLCD: National Land Cover Database

NREPA: Natural Resources and Environmental Protection Act

PA 233: Public Act 233 of 2023 as defined in Michigan Legislature

Project: Washtenaw Solar Project

Project Area: Approximately 2,412 acres of privately owned land being considered for development in Washtenaw County, Michigan

USDA-NRCS: United States Department of Agriculture-Natural Resources Conservation Service

Washtenaw Solar: Washtenaw Solar Energy LLC

1.0 Introduction

Washtenaw Solar Energy LLC (Washtenaw Solar) contracted with Environmental Consulting & Technology, Inc. (ECT), to develop Exhibit A-9 - Farmland Protection for the Washtenaw Solar Project (Project) located on approximately 2,412 acres of privately owned land in Washtenaw County, Michigan (Project Area). Exhibit A-9 was developed in compliance with Section 6.3.9(a)(b) of the Michigan Public Service Commission (MPSC) certificate for solar energy, wind energy, and energy storage facility requirements pursuant to Public Act 233 (PA 233) of 2023.

More specifically, Exhibit A-9 discusses how the Project will not unreasonably diminish farmland and provides detailed information regarding farmland present within the Project Area and the surrounding area, including Saline Township and Washtenaw County. It is important to note that the Project Area encompasses a larger area than what will be temporarily or permanently disturbed by Project activities. Project activities will be limited to the installation of the panel array, fence lines, access roads, temporary staging areas, electric collection infrastructure, laydown yards, an approximately 207-foot transmission line (herein referred to as the Limits of Disturbance [LOD]). The Project's LOD is further described in Exhibit A-1.1 – Site Plan of this application.

2.0 Section 6.3.9(a) - Farmland Protection

Based on National Land Cover Database information (NLCD), approximately 80 percent of the Project Area is designated as row crop agriculture land use (**Table 1**; MRLC Consortium 2025). This information is also depicted in **Figure 1, Appendix A**, for visual a representation of the data. Although temporary disturbance of vegetation and soil will occur during Project construction, Washtenaw Solar will implement perennial vegetation management over the life span of the Project which will preserve soil health conditions within the Project Area over time.

Table 11. Project Area Land Use Summary

Land Cover Type	Acres within Project Area	% of Project Area
Cultivated Crops	1,917.80	79.53%
Woody Wetlands	175.50	7.28%
Deciduous Forest	141.77	5.88%
Developed Open Space	71.42	2.96%
Pasture / Hay	57.83	2.40%
Developed Low Intensity	41.76	1.73%
Developed Medium Intensity	4.29	0.18%
Developed High Intensity	0.67	0.03%
Open Water	0.44	0.02%
Mixed Forest	0.07	0.003%
Emergent Herbaceous Wetlands	0.00	0.00%
Total	**2,411.56[1]**	**100.00%[1]**

[1] Discrepancies in totals are due to database rounding.
Source: MRLC Consortium 2025

The establishment of the proposed Project will not require regular disturbance. As part of a comprehensive approach to vegetation and soil management onsite, Washtenaw Solar will assess current vegetation on site, including the presence of noxious and invasive species. Once vegetation is characterized, the results in conjunction with soil sampling results will be used to develop site-specific seed mixes that are aimed at providing ground cover. The seed mix will be developed to ensure consistency with natural conditions appropriate for the geography of the site and will not interfere with the performance of the infrastructure. These seed mixes will be developed specifically to the drainage class of the area in which they will be planted. The seed mixes will include plant species which are flowering, deep rooted, and nitrogen fixers which can support soil health. This approach can support soil health due to a reduction of soil structure disturbance, minimized vegetation harvest, and the reduction of herbicide and pesticide applications that may reduce the number of beneficial organisms present in the rooting zone of the soil profile. See **Appendix B** for a Representative Seed Mix list.

The Project facility will be revegetated with low-growing, perennial grasses and forbs. After the vegetation is established, it will be mowed periodically throughout the year to ensure the safety and reliability of Project operations. These management strategies allow the perennial vegetation to develop a robust root system.

This practice of using perennial vegetation for the life of the Project will likely increase the aggregate strength and water stability of the soil structure and positively affect the water infiltration and retention properties of the soil profile. This will occur from the breakdown of organic matter to humus down through the soil profile, which aggregates soil particles to create soil structure. The distribution of the root channels within the soil profile will create macro pores, voids, and aggregate formations, which will improve soil aeration and drainage. Therefore, the operation of the Project is anticipated to improve the soil health conditions of the site throughout the Project's life cycle.

Additionally, Washtenaw Solar is committed to protecting the soils onsite during the various phases of the Project and ensuring that farmland is not unreasonably diminished by Project activities. This includes activities involved in decommissioning the Project at the end of its useful life. Information on specific decommissioning practices pertaining to returning the Project to a farmable condition is included in Exhibit A-13.1 – Decommissioning Plan, which includes a description of the Baseline Soil Health Survey Plan (attachment to Exhibit A-1.4) results, as well as Washtenaw Solar's site restoration and revegetation plan. Restoration efforts by Washtenaw Solar, its successors, or assignees will abide by the specific land restoration commitments agreed to by the individual property owners, as described in each landowner agreement, and/or return the land to at least good or better condition to the extent practicable, leaving any desirable infrastructure as requested by the subsequent landowner. Restoration activities may include regrading to restore land contours, de-compacting soils determined to be compacted, back-filling with native subsoil, fertilizing, adding and/or distributing topsoil (as needed), and seeding to revegetate disturbed areas.

3.0 Section 6.3.9(b) - Farmland Protection

Washtenaw Solar is committed to the preservation of farmland and returning land within the Project Area to farmable conditions at decommissioning. Understanding the current land use and farmland designations within the Project Area is critical to ensuring that farmland is not unreasonably diminished by Project activities. Farmland class designations were obtained from soil survey data published by the United States Department of Agriculture-Natural Resources Conservation Service (USDA-NRCS) (USDA-NRCS 20250. Information on specialty crops was obtained from the USDA National Agricultural Statistics Service (NASS), CroplandCROS (Cropland Collaborative Research Outcomes Systems) website, and is presented in the Cropland Data Layer (CDL) (USDA 2024). The USDA-Agricultural Marketing Service (USDA-AMS) defines specialty crops. According to the USDA-AMS, "Section 101 of the Specialty Crops Competitiveness Act of 2004 (7 U.S.C. 1621 note), amended under section 10010 of the Agricultural Act of 2014, Public Law 113-79, defines specialty crops as, fruits and vegetables, tree nuts, dried fruits, horticulture, and nursery crops (including floriculture). Eligible plants must be cultivated or managed and used by people for food, medicinal purposes, and/or aesthetic gratification to be considered specialty crops." The USDA-AMS provides a list of Specialty Crops in the "*USDA Definition of Specialty Crop"* PDF, which further defines "crop" and groups that are not considered specialty crops, even though they may be used for food or medicinal purposes. This includes soybeans, corn, wheat, and oats, which are present within the Project Area (Agricultural

Marketing Service, USDA, n.d.). Based on farmland classifications from USDA-NRCS soil survey data, the Project Area contains approximately 14% of Saline Township's land designated as prime or potentially prime farmland, and about 1% of such land within Washtenaw County. In addition, the Project Area accounts for less than 11% of all farmland in Saline Township and under 1% of all farmland in Washtenaw County.

Table 2 below shows the acreage of farmland within the Project Area, Saline Township, and Washtenaw County, according to farmland class designation. This information is shown in **Figure 2, Appendix A**, for visual reference.

Table 22. Farmland by Type within Saline Township, Washtenaw County, and the Project Area

Farmland Type	Saline Township (Acres)	Saline Township (Percent)	Washtenaw County (Acres)	Washtenaw County (Percent)	Project Area (Acres)	Project Area (Percent)	Percent of Township within the Project Area (Percent)	Percent of County within the Project Area (Percent)
Prime farmland, if drained	9,705.79	43.60%	128,628.69	27.82%	1,555.55	47.92%	16.03%	1.21%
Prime Farmland	6,398.96	28.75%	97,930.27	21.18%	695.60	28.84%	10.87%	0.71%
Farmland of local importance	5,409.77	24.30%	182,207.83	39.41%	493.29	20.46%	9.12%	0.27%
Not prime farmland	742.92	3.34%	53,520.50	11.58%	67.13	2.78%	9.04%	0.13%
Prime farmland if protected from flooding or not frequently flooded during the growing season	2.92	0.01%	61.18	0.01%	0.00	0.00%	0.00%	0.00%
Total	**22,260.35**	**100.0%**	**462,348.48**	**100.00%**	**2,411.56**	**100.00%**	**-**	**-**

Source: USDA-NRCS 2025

Tables 3 and 4 below summarize the acreage and percentage of specialty crops within the Township and County, as well as the Project Area. Additionally, **Figure 3, Appendix A** shows the acreage of specialty crops grown in Washtenaw County, Saline Township, and within the Project Area.

Table 3. Saline Township Specialty Crop Data

Category	Total acreage of crop within the township (Acres)	Percent of crop type within the township (Percentage)	Percent of crop in the township utilized by Project (Percentage)	Total acreage of crop type within the Project Area (Acres)	Percent of crop type within the Project Area (Percentage)
Dry Beans	6.79	>0.01%	0.00%	0.03	>0.01%
Sweet Corn	5.71	>0.01%	0.05%	0.30	>0.01%
Other Crops*	5.30	>0.01%	0.04%	0.20	>0.01%
Potatoes	2.79	>0.01%	0.01%	0.02	>0.01%
Misc Vegs & Fruits*	1.43	>0.01%	0.00%	0.00	>0.01%
Apples	1.11	>0.01%	0.03%	0.03	>0.01%
Tomatoes	1.09	>0.01%	0.27%	0.30	>0.01%
Other Tree Crops*	0.91	>0.01%	0.00%	0.00	>0.01%
Cucumbers	0.64	>0.01%	0.12%	0.07	>0.01%
Peppers	0.64	>0.01%	0.00%	0.00	>0.01%
Grapes	0.59	>0.01%	0.00%	0.00	>0.01%
Walnuts	0.20	>0.01%	0.00%	0.00	>0.01%
Strawberries	0.12	>0.01%	0.21%	0.02	>0.01%
Pumpkins	0.10	>0.01%	0.25%	0.02	>0.01%
Hops	0.10	>0.01%	0.00%	0.00	>0.01%
Total	**27.54**	**-**	**-**	**1.00**	**-**

Source: USDA 2024

* Unable to determine specialty crop status, due to lack of specific crop within category.

Table 4. Washtenaw County Specialty Crop Data

Category	Total acreage of cropland type within the county (Acres)	Percent of cropland type within the county (Percentage)	Percent of cropland type in the county utilized by Project (Percentage)	Total acreage of cropland type within the Project Area (Acres)	Percent of cropland type within the Project Area (Percentage)
Other Crops	207.95	>0.01%	0.00	0.20	>0.01%
Dry Beans	163.49	>0.01%	0.00	0.03	>0.01%
Pumpkins	152.35	>0.01%	0.00	0.02	>0.01%
Misc Vegs & Fruits*	70.69	>0.01%	0.00	0.00	>0.01%
Apples	63.76	>0.01%	0.00	0.03	>0.01%
Sweet Corn	47.64	>0.01%	0.01	0.30	>0.01%
Peppers	36.23	>0.01%	0.00	0.00	>0.01%
Potatoes	25.53	>0.01%	0.00	0.02	>0.01%
Cucumbers	18.88	>0.01%	0.00	0.07	>0.01%
Tomatoes	14.68	>0.01%	0.02	0.30	>0.01%
Christmas Trees	12.83	>0.01%	0.00	0.00	>0.01%
Other Tree Crops*	11.53	>0.01%	0.00	0.00	>0.01%
Walnuts	8.03	>0.01%	0.00	0.00	>0.01%
Cabbage	7.22	>0.01%	0.00	0.00	>0.01%
Strawberries	4.82	>0.01%	0.01	0.02	>0.01%
Grapes	2.30	>0.01%	0.00	0.00	>0.01%
Hops	0.86	>0.01%	0.00	0.00	>0.01%
Sunflower**	0.37	>0.01%	0.00	0.00	>0.01%
Squash	0.20	>0.01%	0.00	0.00	>0.01%
Mint	0.15	>0.01%	0.00	0.00	>0.01%
Peaches	0.02	>0.01%	0.00	0.00	>0.01%
Total	**849.53**	**-**	**-**	**1.00**	**-**

Source: USDA 2024

* Unable to determine specialty crop status, due to lack of specific crop within category.

** Would be considered a specialty crop if being used for aesthetic gratification; would not be considered specialty crop if being used for production of seed.

4.0 Conclusion

Washtenaw Solar is dedicated to ensuring that soils and farmlands are managed properly throughout the design, construction, operation, and decommissioning stages of the Project. According to the farmland class designations obtained from USDA-NRCS soil survey data, approximately 14% of land classified as prime or potentially prime farmland within Saline Township, and approximately 1% of such land within Washtenaw County, occurs within the Project Area. Furthermore, less than 11% of all farmland in Saline Township and less than 1% of all farmland in Washtenaw County is located within the Project Area. Washtenaw Solar has completed various background studies designed to gather information on current land uses, crops by type, and baseline soils data. Washtenaw Solar will update or complete future studies as necessary to obtain permits, determine the best course of action for land management, and ensure that the Project can be safely decommissioned. This may include developing vegetation and soil management practices based on site conditions as informed by the soil survey completed by ECT in 2025, and reviewing the decommissioning plan every five years as required.

Based upon the planned vegetation use across the Project Area throughout the Project's lifespan, current and future land conservation practices, many of which will be continued throughout the Project's lifespan and in consideration of future studies that Washtenaw Solar will complete, Washtenaw Solar believes that the soil condition will not be unreasonably diminished by the construction and operation of the proposed facility. Washtenaw Solar will ensure that land is returned to at least as good or better condition at Project decommissioning.

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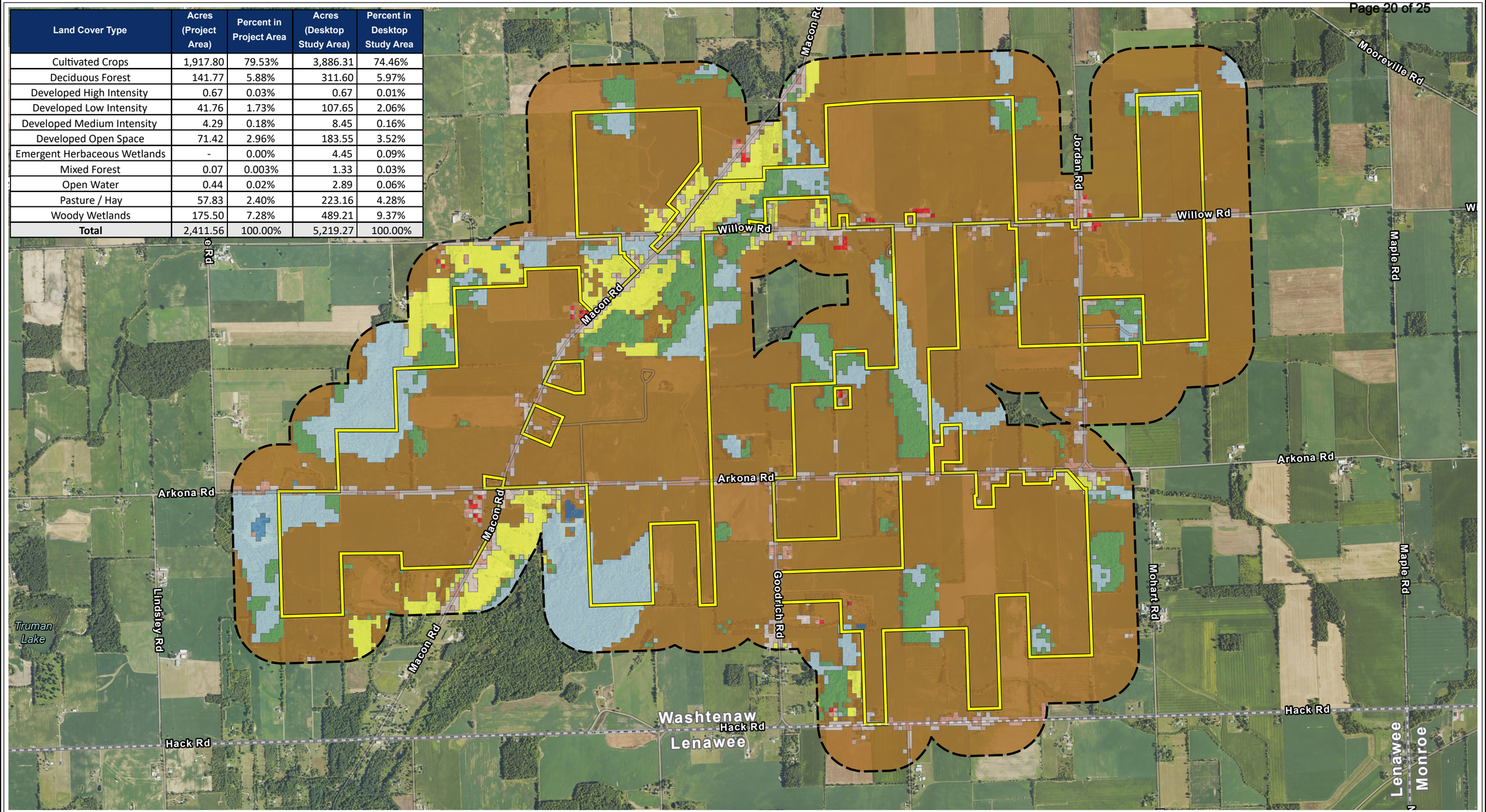
Appendix A - Figures

Land Cover Type	Acres (Project Area)	Percent in Project Area	Acres (Desktop Study Area)	Percent in Desktop Study Area
Cultivated Crops	1,917.80	79.53%	3,886.31	74.46%
Deciduous Forest	141.77	5.88%	311.60	5.97%
Developed High Intensity	0.67	0.03%	0.67	0.01%
Developed Low Intensity	41.76	1.73%	107.65	2.06%
Developed Medium Intensity	4.29	0.18%	8.45	0.16%
Developed Open Space	71.42	2.96%	183.55	3.52%
Emergent Herbaceous Wetlands	-	0.00%	4.45	0.09%
Mixed Forest	0.07	0.003%	1.33	0.03%
Open Water	0.44	0.02%	2.89	0.06%
Pasture / Hay	57.83	2.40%	223.16	4.28%
Woody Wetlands	175.50	7.28%	489.21	9.37%
Total	2,411.56	100.00%	5,219.27	100.00%



Project Area (± 2,411.56 Ac.)
1,000-ft Buffer
Land Cover Type (NLCD, 2023)
Open Water
Developed, Open Space
Developed, Low Intensity
Developed, Medium Intensity
Developed, High Intensity
Deciduous Forest
Mixed Forest
Pasture/Hay
Cultivated Crops
Woody Wetlands
Emergent Herbaceous Wetlands

N
0 1,000 2,000
Feet

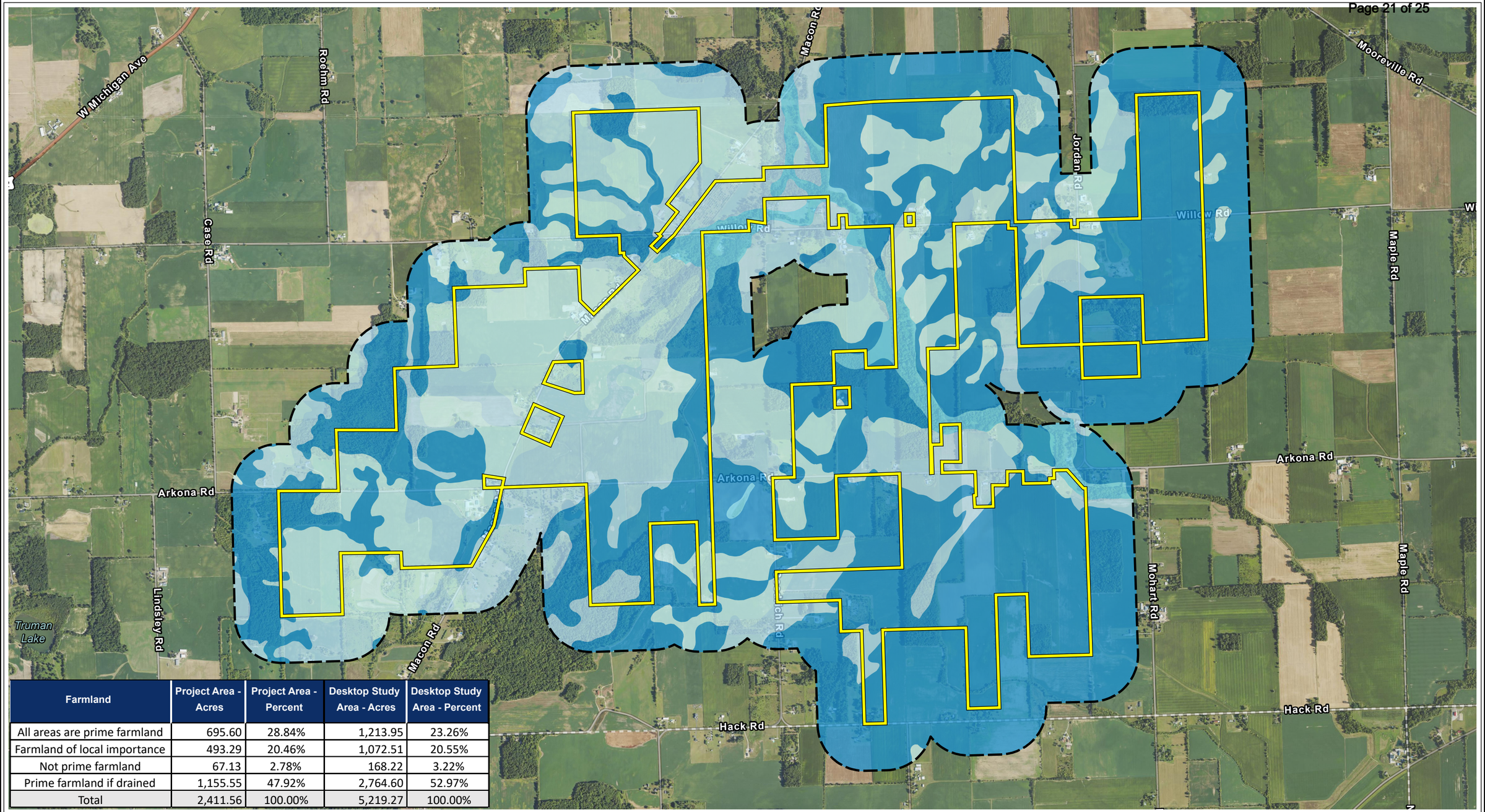
Base Layer: NAIP Aerial Imagery 2023

Figure 1
National Land Cover Database

Washtenaw Solar Energy Project
Washtenaw County, Michigan

Date: 8/15/2025

ECT



Farmland	Project Area - Acres	Project Area - Percent	Desktop Study Area - Acres	Desktop Study Area - Percent
All areas are prime farmland	695.60	28.84%	1,213.95	23.26%
Farmland of local importance	493.29	20.46%	1,072.51	20.55%
Not prime farmland	67.13	2.78%	168.22	3.22%
Prime farmland if drained	1,155.55	47.92%	2,764.60	52.97%
Total	2,411.56	100.00%	5,219.27	100.00%

Project Area (± 2,411.56 Ac.)
1,000-ft Buffer
NRCS Soils - Farmland
All areas are prime farmland
Farmland of local importance
Not prime farmland
Prime farmland if drained
Prime farmland if protected from flooding or not frequently flooded during the growing season

N
0 1,000 2,000
Feet

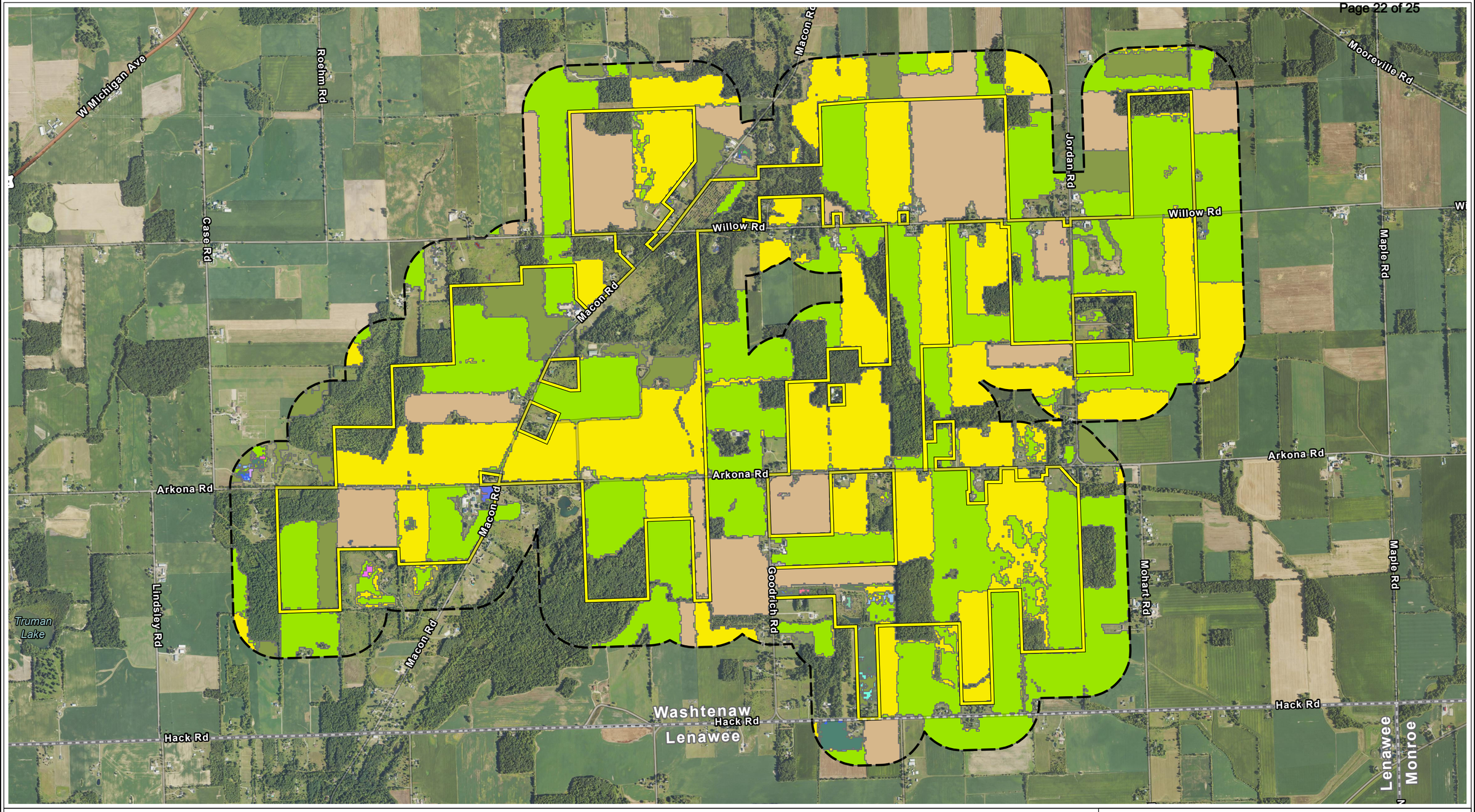
Base Layer: USDA NAIP Aerial Imagery 2023

Figure 2
NRCS Soils - Farmland

Washtenaw Solar Energy Project
Washtenaw County, Michigan

Date: 8/15/2025

ECT



Project Area (± 2,411.56 Ac.)
1,000-ft Buffer

Cropland Type (USDA, 2024)

- Alfalfa
- Apples
- Barley
- Canola
- Clover/Wildflowers
- Corn
- Cucumbers
- Dbl Crop WinWht/Soybeans
- Dry Beans
- Fallow/Idle Cropland
- Grapes
- Misc Vegs & Fruits
- Oats
- Other Crops
- Other Hay/Non Alfalfa
- Other Tree Crops
- Peppers
- Potatoes
- Pumpkins
- Rye
- Sod/Grass Seed
- Sorghum
- Soybeans
- Strawberries
- Sweet Corn
- Switchgrass
- Tomatoes
- Uncultivated
- Winter Wheat

N

0 1,000 2,000
Feet

Base Layer: NAIP Aerial Imagery 2023

Figure 3
Cropland Data

Washtenaw Solar Energy Project
Washtenaw County, Michigan

Date: 8/15/2025

ECT

Appendix B - Representative Seed Mix

Business Confidential: Not for Distribution

Washtenaw Solar Energy Project
Representative Seed Mix

This seed mix is representative in nature and subject to change based on various factors including site conditions, seed availability and cost at the time of purchase, regional weather conditions around time of planting, and changes based on site conditions throughout construction.

Proposed Vegetative Cover: Permanent Array Mix

Scientific Name	Common Name	Family	Origin	Physiognomy	Typical Mature Height (ft)	Lifecycle	Blooming Months
Perennial Graminoids							
Agrostis stolonifera	creeping bent	Poaceae	non-native	grass	1.0	perennial	April-Nov.
Elymus virginicus	virginia wild-rye	Poaceae	native	grass	2.5	perennial	July-Aug.
Festuca brevipila	Hard Fescue	Poaceae	non-native	grass	0.8	perennial	May-July
Festuca ovina	Sheep Fescue	Poaceae	non-native	grass	1.0	perennial	May-June
Festuca rubra subsp. commutata or fallax	Chewing's Fescue	Poaceae	non-native	grass	1.0	perennial	May-July
Festuca rubra subsp. rubra	Creeping Red Fescue	Poaceae	non-native	grass	1.5	perennial	May-July
Carex cristatella	sedge	Cyperaceae	native	sedge	2.0	perennial	June-Aug.
Carex vulpinoidea	sedge	Cyperaceae	native	sedge	2.0	perennial	June-July
Glyceria striata	fowl manna grass	Poaceae	native	grass	2.0	perennial	June-Sept.
Juncus tenuis	path rush	Juncaceae	native	rush	0.5	perennial	June
Poa pratensis	kentucky bluegrass	Poaceae	non-native	grass	1.5	perennial	April-Aug.
Schizachyrium scoparium	little bluestem	Poaceae	native	grass	2.0	perennial	July-Oct.
Perennial Wildflowers							
Achillea millefolium	yarrow	Asteraceae	native	forb	2.0	perennial	June-Nov.
Prunella vulgaris	self-heal	Lamiaceae	native	forb	0.8	perennial	June-Sept.
Trifolium pratense	red clover	Fabaceae	non-native	forb	1.0	perennial	June-Oct.
Trifolium repens	white clover	Fabaceae	non-native	forb	0.5	perennial	May-Nov.

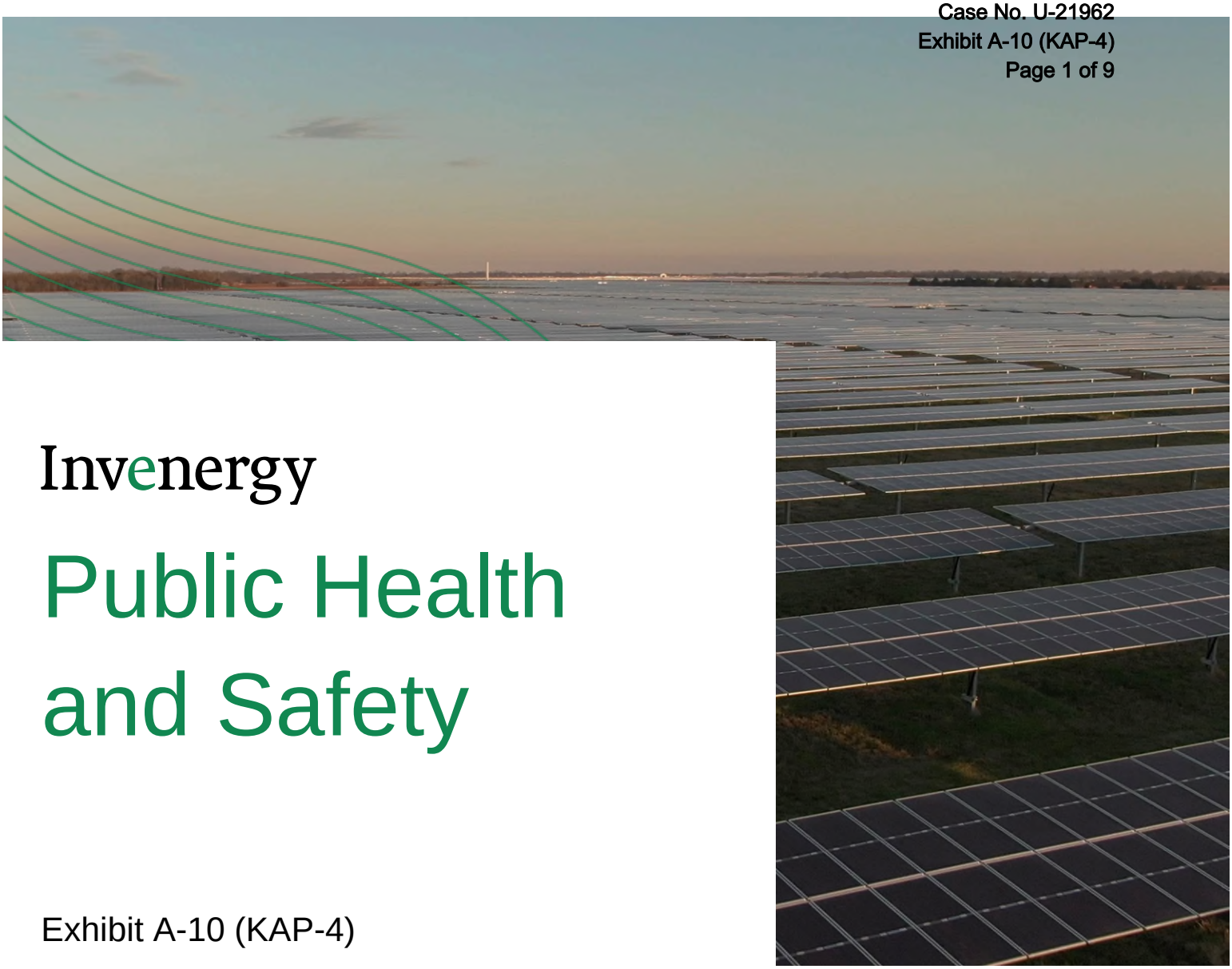
Proposed Vegetative Cover: Buffer Pollinator Mix

Scientific Name	Common Name	Family	Origin	Physiognomy	Typical Mature Height (ft)	Lifecycle	Blooming Months
Perennial Grasses							
Agrostis stolonifera	creeping bent	Poaceae	non-native	grass	1	perennial	April-Nov.
Carex granularis	sedge	Cyperaceae	native	sedge	1	perennial	May
Carex hirsutella	sedge	Cyperaceae	native	sedge	2	perennial	May
Carex molesta	sedge	Cyperaceae	native	sedge	2	perennial	May-June
Festuca brevipila	Hard Fescue	Poaceae	non-native	grass	0.8	perennial	May-July
Festuca ovina	Sheep Fescue	Poaceae	non-native	grass	1	perennial	May-June
Festuca rubra subspecies	Creeping Red	Poaceae	non-native	grass	1.5	perennial	May-July
Glyceria striata	fowl manna grasses	Poaceae	native	grass	2	perennial	June-Sept.
Juncus dudleyi	dudleys rush	Juncaceae	native	rush	2	perennial	June
Poa compressa	canada bluegrass	Poaceae	non-native	grass	1	perennial	June-July
Poa pratensis	kentucky bluegrass	Poaceae	non-native	grass	1.5	perennial	April-Aug.
Perennial Wildflowers							
Trifolium repens	white clover	Fabaceae	non-native	forb	0.5	perennial	June-Sept.
Perennial Grasses, Sedges, Rushes							
Andropogon gerardii	big bluestem	Poaceae	native	grass	5.0	perennial	July-Sept.
Carex vulpinoidea	sedge	Cyperaceae	native	sedge	2.0	perennial	June-July
Elymus virginicus	virginia wild-rye	Poaceae	native	grass	2.5	perennial	July-Aug.
Juncus effusus	soft-stemmed	Juncaceae	native	rush	2.5	perennial	July-Sept.
Panicum virgatum	switch grass	Poaceae	native	grass	3.5	perennial	July-Sept.
Schizachyrium scoparium	little bluestem	Poaceae	native	grass	2.0	perennial	July-Oct.
Scirpus atrovirens	bulrush	Cyperaceae	native	sedge	3.0	perennial	June-Aug.
Sorghastrum nutans	indian grass	Poaceae	native	grass	5.0	perennial	Aug.-Sept.
Perennial Wildflowers							
Achillea millefolium	yarrow	Asteraceae	native	forb	2.0	perennial	June-Nov.
Anemone canadensis	canada anemone	Ranunculaceae	native	forb	1.0	perennial	May-July
Coreopsis lanceolata	sand coreopsis	Asteraceae	native	forb	1.0	perennial	May-Aug.
Coreopsis tripteris	tall coreopsis	Asteraceae	native	forb	5.0	perennial	July-Oct.
Doellingeria umbellata; as	flat-topped white aster	Asteraceae	native	forb	3.5	perennial	July-Sept.
Echinacea purpurea	purple coneflower	Asteraceae	non-native	forb	2.5	perennial	July-Sept.
Eupatorium perfoliatum	boneset	Asteraceae	native	forb	3.0	perennial	July-Sept.
Euthamia graminifolia	grass-leaved goldenrod	Asteraceae	native	forb	2.5	perennial	July-Sept.
Heliopsis helianthoides	false sunflower	Asteraceae	native	forb	3.0	perennial	June-Sept.
Liatris spicata	marsh blazing-star	Asteraceae	native	forb	3.5	perennial	July-Sept.
Lobelia siphilitica	great blue lobelia	Campanulaceae	native	forb	2.5	perennial	July-Oct.
Mimulus ringens	monkey-flower	Phrymaceae	native	forb	1.5	perennial	June-Sept.
Monarda fistulosa	wild-bergamot	Lamiaceae	native	forb	2.5	perennial	July-Aug.
Packera aurea	golden ragwort	Asteraceae	native	forb	1.0	perennial	May-June
Penstemon digitalis	foxglove beard	Plantaginaceae	native	forb	3.0	perennial	June-July
Pycnanthemum virginianu	common mountain mint	Lamiaceae	native	forb	2.0	perennial	July-Sept.
Ratibida pinnata	yellow coneflower	Asteraceae	native	forb	3.5	perennial	July-Sept.
Rudbeckia hirta	black-eyed susan	Asteraceae	native	forb	1.8	perennial	June-Oct.
Rudbeckia triloba	three-lobed coneflower	Asteraceae	native	forb	3.0	biennial	Aug.-Oct.
Silphium terebinthinaceu	prairie-dock	Asteraceae	native	forb	5.0	perennial	July-Sept.
Solidago gigantea	late goldenrod	Asteraceae	native	forb	4.0	perennial	Aug.-Sept.
Solidago juncea	early goldenrod	Asteraceae	native	forb	2.5	perennial	July-Aug.

*Seed densities and weights are given as Pure Live Seed (PLS)

Symphyotrichum lanceola	panicled aster	Asteraceae	native	forb	3.0	perennial	Sept.-Oct.
Symphyotrichum novae-a	new england aster	Asteraceae	native	forb	2.5	perennial	Aug.-Oct.
Symphyotrichum pilosum	hairy aster	Asteraceae	native	forb	2.0	perennial	Sept.-Nov.
Verbena hastata	blue vervain	Verbenaceae	native	forb	3.0	perennial	July-Sept.
Vernonia gigantea	tall ironweed	Asteraceae	native	forb	4.0	perennial	Aug.-Sept.
Zizia aurea	golden alexanander	Apiaceae	native	forb	2.0	perennial	April-June

*Seed densities and weights are given as Pure Live Seed (PLS)



Invenergy

Public Health and Safety

Exhibit A-10 (KAP-4)

PREPARED FOR:

WASHTENAW SOLAR ENERGY LLC

Invenergy

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Invenergy

1.0 Introduction

Washtenaw Solar Energy LLC ("Washtenaw Solar") is proposing a 150 MW solar facility located on privately-owned land in Saline Township, Washtenaw County, Michigan (the "Project"). According to the Filing Guidelines, public health and safety impacts of the Project are considered acceptable if the criteria detailed below are met.

1. Setbacks

   i. Occupied community buildings and dwellings on non-participating properties – 300 feet from nearest point on the outer wall.

   ii. Public road right of way – 50 feet measured from the nearest edge of a public road right-of-way.

   iii. Non-participating parties – 50 feet measured from the nearest shared property line.

2. Fencing – National Electric Code, most recent version.

3. Maximum height – Solar array may not exceed 25 feet above ground at full tilt.

4. Sound - Must not generate >55 decibel (dB); (average hourly) at nearest wall of nonparticipating property. [Filing Guidelines at Section 6.3.10(a).]

This exhibit describes how the Project complies with the above design criteria, the provisions of 2023 PA 233, MCL 460.1226(8)(a), and therefore is does not present an unreasonable threat to public health or safety. MCL 460.1226(7)(g).

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2.0 Setbacks

2.1 Occupied Community Buildings and Dwellings on Non-Participating Properties

The Filing Guidelines provide that occupied community buildings and dwellings on non-participating properties must be 300 feet from the nearest point on the outer wall.

The American Land Title Association/National Society of Public Surveyors ("ALTA/NSPS") land title survey commissioned by Washtenaw Solar and completed for the Project identified buildings and structures present within the Study Area. No occupied community buildings, such as schools, places of worship, day-care facilities, public libraries, community centers, or other similar buildings, were identified within the Project Area or Study Area. Dwellings (residences) were identified and are mapped out as shown in **Exhibit A-1.1(c) (KAP-1)**.

A setback of 300 feet was applied from the outer wall of these identified residences to the closest above ground facility feature, which is the project perimeter fence line, consistent with MCL 460.1226(8)(a)(*i*). Washtenaw Solar treated residences on participating parcels the same as residences on non-participating parcels. Aerial imagery was used to determine the outer wall of identified residences. A boundary was drawn around the outer boundary of a residence based on this imagery, and a 300-foot setback was then applied to this drawn boundary. This setback was used as an exclusion zone during the creation of the site facilities plan for all above ground site facilities.

The Project is not expected to encroach on this 300-foot setback from occupied buildings and dwellings. The current proposed limits of the Project fence line are not expected to expand as the permitting fence line contains sufficient DC and AC contingency. The number of modules per inverter (DC contingency) can be decreased without impact to nameplate capacity but will reduce energy production. The full number of inverters proposed (AC contingency) may be decreased without a change to the nameplate capacity. The fence line shown in the Application is expected to be the maximum extents of the Project, so that no future encroachment on this required setback is anticipated.

2.2 Public Road Right-of-Way ("ROW")

The Filing Guidelines provide that 50 feet must be measured from the nearest edge of a public road ROW.

The ALTA/NSPS land title survey completed for Washtenaw Solar also identified road ROW within the Study Area. Road rights-of-way identified in this survey are shown in **Exhibit A-1.1(c) (KAP-1)**.

A setback of 50 feet was applied to the outer edge of these identified road ROW. This setback was used as an exclusion zone during the formulation of the site facilities plan for all above ground features. As the perimeter fence is the outermost above ground feature for all photovoltaic ("PV") areas, this 50-foot setback is measured from the outer bound of the ROW to the fence line.

Encroachment within this 50-foot setback from road ROW is not expected. The current proposed limits of the Project fence line are not expected to expand as the permitting fence line contains sufficient DC and AC contingency. The number of modules per inverter (DC contingency) can be decreased without impact to nameplate capacity but will reduce energy production. The full number of inverters proposed (AC contingency) may be decreased without a change nameplate capacity. The fence line shown in the Application is expected to be the maximum extents of the Project, so that no future encroachment on this required setback is anticipated.

2.3 Non-Participating Parties

The Filing Guidelines provide that 50 feet must be measured from the nearest shared property line.

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The ALTA/NSPS land title survey completed for Washtenaw solar also identified non-participating property lines adjacent to the Study Area. Non-Participating parcel property lines are mapped out as shown in **Exhibit A-1.1(c) (KAP-1)**.

A setback of 50 feet was applied to the outer edge of these identified non-participating property lines. This setback was used as an exclusion zone during the formulation of the site facilities plan for all above ground features. As the perimeter fence is the outermost above ground feature for all PV areas, this 50-foot setback is measured from the outer wall of the residence to the fence line.

Some portions of the fence line may be more than 50 feet away from the nearest non-participating parcel property line. In these instances, other constraining features (such as residences, road ROWs, and wetlands) are more restrictive than the property lines.

Encroachment within this 50-foot setback from non-participating property lines is not expected. The current proposed limits of the Project fence line are not expected to expand as the permitting fence line contains sufficient DC and AC contingency. The number of modules per inverter (DC contingency) can be decreased without impact to nameplate capacity but will reduce energy production. The full number of inverters proposed (AC contingency) may be decreased without a change nameplate capacity. The fence line shown in the Application is expected to be the maximum extents of the Project, so that no future encroachment on this required setback is anticipated.

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3.0 Fencing

The Filing Guidelines provide that the most recent version of the National Electric Code ("NEC") should be met. The fencing planned for the Project will comply with the NEC in effect on November 29, 2024.

3.1 Substation Fencing

The fencing planned for substation for the Project is a seven (7) foot-tall chain link fence with one (1) foot of barbed wire topping. No electric fencing (or "shock" fencing) is planned for the Project. Substation fence grounding and bonding will be compliant with Article 250.194, Section (A) – Metal Fences of the NEC as referenced below:

> If metal fences are located within 5 meters (16 feet) of the exposed electrical conductors or equipment, the fence shall be bonded to the grounding electrode system with wire-type bonding jumpers as follows:
>
> - Bonding jumpers shall be installed at each fence corner and at maximum 50-meter (160 foot) intervals along the fence.
> - If bare overhead conductors cross the fence, bonding jumpers shall be installed on each side of the crossing.
> - Gates shall be bonded to the gate support post, and each gate support post shall be bonded to the grounding electrode system.
> - Any gate or other opening in the fence shall be bonded across the opening by a buried bonding jumper.
> - The grounding grid or grounding electrode systems shall be extended to cover the swing of all gates.
> - The barbed wire strands above the fence shall be bonded to the grounding electrode system.
>
> Alternate designs performed under engineering supervision shall be permitted for grounding or bonding metal fences.

3.2 Array Fencing

The fencing planned for the array area of the Project is a seven (7) foot-tall galvanized woven wire fencing with openings of less than 6 inches. Fencing around array areas are planned to be at least 20 feet away from all electrical equipment, so that the requirements in Article 250.194 do not apply. Instead, PV area fencing will comply with Article 691.11 and, by reference, Article 691.6. As stated in Article 6911.6 – Engineered Design:

> Documentation of the electrical portion of the engineered design of the electric supply station shall be stamped and provided upon the request of the AHJ. Additional stamped independent engineering reports detailing compliance of the design with applicable electrical standards and industry practice shall be provided upon request of the AHJ. The independent engineer shall be a licensed professional electrical engineer retained by the system owner or installer. This documentation shall include details of conformance of the design with Article 690, and any alternative methods to Article 690, or other articles of this Code.

Washtenaw Solar will comply with the NEC with regard to fencing requirements for the Project.

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As referenced in Article 691.6, Washtenaw Solar will contract a licensed professional electrical engineer/electrical Engineer of Record (“EOR”) for the Issued for Construction (“IFC”) design. The EOR may recommend additional grounding requirements not stated within the NEC, but the IFC design will meet the requirements stated above at a minimum. Washtenaw Solar will follow the recommendation of all grounding requirements proposed by the electrical EOR.

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4.0 Maximum Height

The Filing Guidelines provide that the solar arrays may not exceed twenty-five (25) feet above ground at full tilt.

The maximum height of panels at full tilt will not exceed twenty-five (25) feet above ground. The expected height of the solar panels will be dependent on any contractually required ground clearance and freeboard (the distance from lower edge of the module at full tilt to the anticipated flood depth) above the 24-hour, 100-year storm inundation flood depths. Where no flooding is present on site, the top edge of the panel is expected to be one hundred and two (102) inches above grade (8 feet, 6 inches) when at full tilt. For select areas where higher inundation depths are expected, the top edge of the panel will be less than twenty-five (25) feet.

Washtenaw Solar will keep solar array heights below twenty-five (25) feet for practical purposes, as well. There are steel cost savings at the proposed no-flood and max-flood heights described above. Additionally, the lower heights allow for the installation of tracker systems and modules without the need for ladders, which aids in construction efficiency and safety.

The height proposed for the Project is not anticipated to exceed the maximums, described above, in Washtenaw Solar's IFC design. The maximum height proposed accounts for variations of equipment manufacturers considered for the Project—both with tracker type/tilt angle and module length. Washtenaw Solar's preliminary hydrology study suggests the maximum flood depth modules will be sited in will be up to two (2) feet.

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5.0 Sound

The Filing Guidelines provide that sound must not generate more than fifty-five (55) decibels ("dB") (average hourly) at the nearest wall of nonparticipating properties.

To limit the noise output on adjacent non-participating properties, Washtenaw Solar first determined the noise-emitting equipment: the Project substation and the inverters. Since noise output levels dissipate over distance, the Project was designed with these features placed within the center of PV areas where possible.

After the location of these noise-emitting equipment was selected, Washtenaw Solar commissioned Hankard Environmental, Inc. ("Hankard") to complete a noise study using the inverter and substation locations as inputs. Hankard mapped out noise levels from 31 dB to 67 dB in 2 dB intervals. The 55 dB contour line provided in this study was then compared to buildings and structures mapped out on adjacent properties. Since the 55 dB limit did not reach any buildings or structures on non-participating properties, the inverter and substation locations did not need to be altered.

Inverter locations are not expected to change in a manner that would increase the decibel level. Placing inverters central to their power block—or the group of modules that will connect into the inverter—minimizes noise through distance. Placing inverters central to their power blocks is also optimal from an electrical design perspective, as it reduces the length of electrical cable needed to connect modules to the inverter. Therefore, inverter locations are not anticipated to shift in a manner that exceeds the 55 dB limit with regard to the sound setback. Additionally, as stated above, the Project has sufficient contingency so that the number of inverters is not expected to increase.

Similarly, the substation location is not expected to change substantially (see **Exhibit A-1.6 (JMP-2)**. This location is based on the Project's Generator Interconnection Agreement, **Exhibit A-12 (TSD-13)** and Washtenaw Solar's right to exercise a purchase option agreement with the property owners of the parcel where the substation will be located.

Invenergy

Dark Sky Lighting Plan

Exhibit A-11 (JMP-8)

PREPARED FOR:

WASHTENAW SOLAR ENERGY LLC

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Invenergy

1.0 Introduction

Washtenaw Solar Energy LLC ("Washtenaw Solar") is developing a 150 MW solar energy facility located in Saline Township, Washtenaw County, Michigan ("Project"). As part of the development of the Project, Washtenaw Solar has developed the following lighting plan which aims to reduce light pollution and minimize the amount of light that escapes upward into the sky and adhere to DarkSky International principles where possible. The DarkSky International Principles are included as **Appendix A.** The site will need to have dusk-till-dawn lighting during both construction and operation phases for certain elements of the Project. The lighting will provide security and safety. Impact to adjacent properties and light that escapes upward into the sky will be minimized.

2.0 Lighting

2.1 Construction Lighting

Lighting during the construction phase will be necessary for equipment operation, site construction, and security. Work will occur between 7:00 AM and 7:00 PM or sunset (whichever is later). Lighting will be necessary near the construction trailer and in laydown yards, at the Substation location, and occasionally around key array areas during shorter days of the year. Work outside these hours will be limited and will be prioritized away from adjacent residences and roadways. These work hours aim to keep the overall construction phase of the Project shorter.

2.2 Work Area Lighting

Work area visibility will be enhanced with portable spot lighting and equipment mounted lighting. These areas will only be lit when active construction is taking place and will not remain lit when construction is not active. The need for this lighting is to provide safe working conditions for equipment and labor constructing the Project. The portable lighting will move throughout the duration of the Project to the active worksite areas. Portable spot lighting will be oriented away from roadways and residences where possible. Areas adjacent to residences and roadways will be prioritized so that active working occurs in daylight hours when possible. Direct glare will be considered so that spot lighting is not disturbing residences and vehicles on adjacent roads.

2.3 Equipment Lighting

Equipment will have headlights and spotlights so that the immediate area can be illuminated. These will be operational only when needed for operator and site safety and when there is active construction, typically near dusk and dawn and after sunset, on occasion. Spotlights will be cab-mounted and boom-mounted. When practical, equipment will work parallel to nearby roads or residences or far enough away so that light trespass from equipment is kept minimal.

2.4 Security Lighting

Temporary construction lighting will be needed at night to provide security. Area lighting may be provided around equipment, material lay-down areas and temporary construction facilities such as trailers. Area lighting will be provided by temporary downward facing lighting. Motion activated flood or spot lighting may also be used. Stationary building lighting may be used on the temporary trailers to provide safety and security. The need for lighting may be adjusted throughout Project based on any additional needs for security or safety.

2.5 Operational Lighting

Permanent lighting is required during facility operations around the Substation and Switchyard. This permanent lighting will be downward facing lighting for security purposes. These lights will be turned on either by a local switch, as needed, or by motion sensors that will be triggered by movement. This will ensure that the nearby residence will not experience disturbance from constant, 24-hour flood lighting. A specification sheet for a sample light is provided as **Appendix B.**

Invenergy

3.0 Complaint Resolution

Washtenaw Solar is committed to addressing any concerns from adjacent landowners and citizens. Washtenaw Solar's complaint resolution process as provided in **Exhibit A-1.16 (TSD-3)** will be implemented to respond to any complaints regarding lighting issues during construction and operations.

Appendices

4.0 Appendices

Appendix A: DarkSky International Principles

Five Lighting Principles for Responsible Outdoor Lighting

DarkSky

Illuminating Engineering Society

Responsible outdoor lighting is

1 Useful

Use light only if it is needed

All light should have a clear purpose. Consider how the use of light will impact the area, including wildlife and their habitats.

2 Targeted

Direct light so it falls only where it is needed

Use shielding and careful aiming to target the direction of the light beam so that it points downward and does not spill beyond where it is needed.

3 Low Level

Light should be no brighter than necessary

Use the lowest light level required. Be mindful of surface conditions, as some surfaces may reflect more light into the night sky than intended.

4 Controlled

Use light only when it is needed

Use controls such as timers or motion detectors to ensure that light is available when it is needed, dimmed when possible, and turned off when not needed.

5 Warm-colored

Use warmer color lights where possible

Limit the amount of shorter wavelength (blue-violet) light to the least amount needed.

Rev. 08-2023

Appendix B: Sample Light Specification Sheet

Catalog Number	
Notes	Type

HOLOPHANE®
LEADER IN LIGHTING SOLUTIONS

PSLED

Predator Small LED

The Predator LED is a robust, sustainable solution for any flood lighting application. The PSLED offers lumen packages for direct replacement of 100 - 1,000 watt HID floods. With energy savings exceeding 60% and expected service life over 20 years, Predator LED luminaires excel at meeting the challenges associated with flood lighting. The PSLED combines robust mechanical design features with the optical expertise, visual comfort and permanence of prismatic glass.

Mechanical

- Rugged grade A360 diecast aluminum (<1% copper)
- Rigorous 5-stage pretreatment polyester topcoat to ensure maximum durability that achieves a scribe creepage rating of 8 after 5,000 hours of salt spray
- Tool-less access with stainless steel latches available
- Adjustable knuckle-mount option, designed to fit 2.375 inch to 2.875 inch tenon with wireway access door
- Adjustable yoke mount option available in galvanized or stainless steel finish
- Tether securely holds cover in place during installation
- All Mountings are 3G vibration rated per ANSI C136.31
- P66 per IEC60068-2-3

Electrical

- Standard surge protection is 20kV/10kA "Extreme Level" per ANSI C136.2
- Optional surge protection is 10kV/5kA per ANSI C136.2
- LED light engines are rated L70 > 100,000 hrs at 25°C
- Electronic driver has an expected life of > 100,000 hours at 25°C
- Rated for -40°C / (-40°F) minimum ambient
- Driver voltage options: 120-277V 50/60 Hz and 347 50/60 Hz and 480V 50/60 Hz
- XVOLT tank driver option for protection against dropped neutrals and other power quality issues
- Single and double fusing options available
- Luminaire available with either a 0-10V dimmable driver or DALI D4i driver. Luminaire is continuous and step dimming capable via AO option or other installed controls

Optical

- Performance is comparable to 100 - 400 watt HPS or 175 - 1,000 watt MH
- Borosilicate prismatic glass ensures longevity and minimizes dirt depreciation while improving visual comfort
- NEMA optical patterns:
  - 4x4 Narrow Spot Flood
  - 4x5 Medium Flood
  - 5x5 Flood
  - 6x5 Wide Flood Rectangle
  - 6x6 Wide Flood
- 3000K, 4000K and 5000K CCT, 70 CRI
- Full Visor option available
- Upper/Bottom Visor option available
- Vandal Guard option available
- Wire guard kit option available

Controls

- DC Connect option is a factory embedded low voltage dusk to dawn photocontrol that increases longevity vs. line voltage controls
- Local Connect option provides a simple means to collect luminaire attribute data, asset location information and execute point-to-point on/off/dim commands via secure Bluetooth link using smartphone platforms.
- Cell Connect option is an embedded network photocontrol with cellular communication. It provides digital switching, precise dimming, and revenue grade metrology. Cell Connect leverage D4i drivers to communicate real-time data to UbiVu, a cloud-based asset management system
- Additionally, it can be equipped with sensor-ready technology to support Zhaga standard sensors enabling smart city solutions utilizing long range network nodes to enable remote monitoring and control.
- Zhaga sensor-ready option allows provides platform at attach Zhaga based controls leveraging the DALI D4i protocol
- 3 pin or 7 pin rotatable NEMA photocontrol receptacle
- Premium solid-state locking-style photocontrol – 10 year rated life
- Extreme long life solid state locking-style photocontrol – 20 year rated life
- Field adjustable output
- nLight Air motion and daylight sensor

Certification & Standards

- UL/CUL Listed for wet location
- Marine environment listed with stainless steel yoke selection and without P3 or P7 photo control receptacle.
- Suitable for operation in an ambient temperature up to 40°C/ 104°F for standard product
- Designlights Consortium® (DLC) qualified product. Not all versions of this product may be DLC qualified. Please check the DLC Qualified Products List at www.designlights.org/QPL to confirm which versions are qualified.

Government Procurement

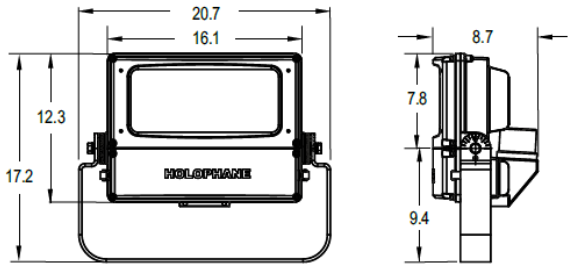
BAA – Buy America(n) Act: Product with the BAA option qualifies as a domestic end product under the Buy American Act as implemented in the FAR and DFARS. Product with the BAA option also qualifies as manufactured in the United States under DOT Buy America regulations. BABA – Build America Buy America: Product with the BAA option also qualifies as produced in the United States under the definitions of the Build America, Buy America Act. Please refer to www.acuitybrands.com/resources/buy-american for additional information.

Warranty

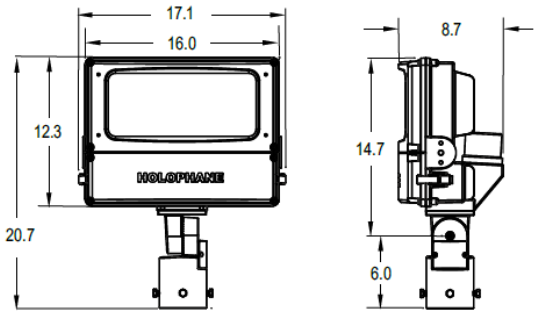
5-year limited warranty. This is the only warranty provided and no other statements in this specification sheet create any warranty of any kind. All other express and implied warranties are disclaimed. Complete warranty terms located at: www.acuitybrands.com/support/warranty/terms-and-conditions

Note: Actual performance may differ as a result of end-user environment and application.
All values are design or typical values, measured under laboratory conditions at 25 °C.

DIMENSIONAL DATA



Yoke Mount Luminaire: Max Weight = 30 lbs (14kg)
Max EPA = 1.8 ft² (0.17 m²)



Tenon Mount Luminaire: Max Weight = 28 lbs (13kg)
Max EPA = 1.9 ft² (0.18 m²)

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PSLED

Predator Small LED

ORDERING INFORMATION

Series		LED Performance Package		Color Temperature		Voltage		Driver		Optics		Mounting Methods	
PSLED	Predator Small LED	P1	5,500 Lumens	30K	3000K CCT	MVOLT	Multiple voltage (120V - 277V)	ZT	0-10V dimmable driver	44	Narrow Spot Flood (4x4)	KM	Tenon Slipfitter - knuckle (cord/leads exit bottom slipfitter)
		P2	7,300 Lumens	40K	4000K CCT	347	347V	D4i	D4i driver	45	Medium Flood (4x5)	KS	Tenon Slipfitter - knuckle (cord exit side of slipfitter)
		P3	12,300 Lumens	50K	5000K CCT	480	480V			55	Flood (5x5)	YMS	Yoke Stainless Steel
		P4	17,600 Lumens			XVOLT[3]	277V-480V			66	Wide Flood (6x6)	YMG	Yoke Galvanized Steel
		P5	21,700 Lumens							65	Wide Flood Rectangle (6x5)		
		P6	27,200 Lumens										
		P7	32,300 Lumens										

Color		Surge Protection		Cord Length		Cord Type	
BKSDP	Black Paint	20KV	STANDARD OPTION: 20kV/10kA w/Indictor Light Extreme Surge (fail off)	04	4 ft cord length	23	12 gage, 3 conductor
BZSDP	Bronze Paint	10KVMP	10kV/5kA MOV pack (fail on)	05	5 ft cord length	43	14 gage, 3 conductor
GHSDP	Graphite Paint			06	6 ft cord length	63	16 gage, 3 conductor
GYSDP	Gray Paint			08	8 ft cord length		
WHSDP	White Paint			10	10 ft cord length		

Top Receptacle		Bottom Receptacle		Photocontrols		Embedded Controls		Misc Options		Accessories (Shipped Seperately)	
NTR	No PER receptacle	NBR	No PER receptaclet	PCLL	Solid State Long Life Photocontrol (fail off)	ALCB	Local Connect Basic	AO	Field Adjustable Output	PSLEDFV BKSDP	Full Visor - Black Paint
PR3	3 Pin rotatable NEMA receptacle	ZRB	Zhaga receptacle bottom	PCSS	Solid State Photocontrol 120-277V (fail off) (Not CSA Listed)	ALCC	Local Connect Custom	F1	Single Fusing	PSLEDFV BZSDP	Full Visor - Bronze Paint
PR7	7 Pin rotatable NEMA receptacle			SH	Shorting Cap	ALCF	Local Connect Full	F2	Double Fusing	PSLEDFV GHSDP	Full Visor - Graphite Paint
				DZP	DTL DZP DC Zhaga Photocontrol	DDC	DC Connect Photocontrol	TL	Tool-less entry with latches	PSLEDFV GYSDP	Full Visor - Gray Paint
						UBC	Cell Connect	XL	No terminal block cover and not certified	PSLEDFV WHSDP	Full Visor - White Paint
						LRSBOR[1]	nLight Air Occ. and daylight sensor (8-15FT)	NL	NEMA Label	PSLEDUBV BKSDP	Upper/Bottom Visor - Black Paint
						HRSBOR[1]	nLight Air Occ. and daylight sensor (15-30FT)	WL	Wet locations listed	PSLEDUBV BZSDP	Upper/Bottom Visor - Bronze Paint
								MRE[2]	Marine listed	PSLEDUBV GHSDP	Upper/Bottom Visor - Graphite Paint
								BAA	Buy America(n) Act and/or Build America Buy America Qualified	PSLEDUBV GYSDP	Upper/Bottom Visor - Gray Paint
										PSLEDUBV WHSDP	Upper/Bottom Visor - White Paint
										PSLEDVG	Vandal Guard
										PSLEDWG	Wire Guard

Note:
1 Only available with KM mounting method.
2 Requires stainless yoke mount (YMS) and cannot be configured with photo control receptacle PR3 or PR7.
3 XVOLT option only available with P4 and P5 performance packages.

MOUNTING OPTIONS

Yoke

Tenon Slipfitter

VISORS & GUARD ACCESSORIES

Upper/Bottom Visor

Full Visor

Wire Guard

Vandal Guard

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PSLED

Predator Small LED

OPTIONS MATRIX

PSLED		Voltage				Driver		Top Receptacle			Bottom Receptacle		Photocontrols				Embedded Controls							
		MVOLT	347	480	XVOLT	ZT	D4i	NTR	PR3	PR7	NBR	ZRB	PCLL	PCSS	SH	DZP	ALCB	ALCC	ALCF	DDC	UBC	HRSBOR	LRSBOR	AO
Voltage	MVOLT					Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
	347					Y	N	Y	Y	Y	Y	Y	Y	N	Y	N	N	N	N	N	N	Y	Y	Y
	480					Y	N	Y	Y	Y	Y	Y	Y	N	Y	N	N	N	N	N	N	Y	Y	Y
	XVOLT					Y	Y	Y	Y	Y	Y	Y	N	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Driver	ZT	Y	Y	Y	Y			Y	Y	Y	Y	N	Y	Y	Y	N	N	N	N	N	N	Y	Y	Y
	D4i	Y	N	N	Y			Y	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	N	N	N
Top Receptacle	NTR	Y	Y	Y	Y	Y	Y				Y	Y	N	N	N	N	Y	Y	Y	Y	Y	Y	Y	Y
	PR3	Y	Y	Y	Y	Y	N				Y	N	Y	Y	Y	N	N	N	N	N	N	N	N	Y
	PR7	Y	Y	Y	Y	Y	Y				Y	N	Y	Y	Y	N	N	N	N	N	N	N	N	Y
Bottom Receptacle	NBR	Y	Y	Y	Y	Y	Y	Y	Y	Y			Y	Y	Y	N	Y	Y	Y	Y	Y	Y	Y	Y
	ZRB	Y	Y	Y	Y	N	Y	Y	N	N			N	N	N	Y	N	N	N	N	N	N	N	N
Photocontrols	PCLL	Y	Y	Y	N	Y	Y	N	Y	Y	Y	N					N	N	N	N	N	N	N	Y
	PCSS	Y	N	N	N	Y	Y	N	Y	Y	Y	N					N	N	N	N	N	N	N	Y
	SH	Y	Y	Y	Y	Y	Y	N	Y	Y	Y	N					N	N	N	N	N	N	N	Y
	DZP	Y	N	N	Y	N	Y	Y	N	N	N	Y					N	N	N	N	N	N	N	N
Embedded Controls	ALCB	Y	N	N	Y	N	Y	Y	N	N	Y	N	N	N	N	N								
	ALCC	Y	N	N	Y	N	Y	Y	N	N	Y	N	N	N	N	N								
	ALCF	Y	N	N	Y	N	Y	Y	N	N	Y	N	N	N	N	N								
	DDC	Y	N	N	Y	N	Y	Y	N	N	Y	N	N	N	N	N								
	UBC	Y	N	N	Y	N	Y	Y	N	N	Y	N	N	N	N	N								
	HRSBOR	Y	Y	Y	Y	Y	N	Y	N	N	Y	N	N	N	N	N								
	LRSBOR	Y	Y	Y	Y	Y	N	Y	N	N	Y	N	N	N	N	N								
	AO	Y	Y	Y	Y	Y	N	Y	Y	Y	Y	N	Y	Y	Y	N								

MATRIX KEY

N = Combination Not available

Y = Valid Option Combination

PSLED		Driver/Voltage							
		MVOLT		347		480		XVOLT	
		ZT	D4I	ZT	D4I	ZT	D4I	ZT	D4I
Performance Package	P1	Y	Y	Y	N	Y	N	N	Y
	P2	Y	Y	Y	N	Y	N	N	Y
	P3	Y	Y	Y	N	Y	N	Y	Y
	P4	Y	Y	Y	N	Y	N	Y	Y
	P5	Y	Y	Y	N	Y	N	Y	Y
	P6	Y	Y	N	N	N	N	N	Y
	P7	Y	Y	N	N	N	N	N	Y

D4i Driver Option Defaults					
Setting	**Receptacle Top**	**Receptacle Bottom**	**Control**	**Default Value**	***Alternate Values***
DALI Power Bus	NTR	NBR	none	**ON**	*Off*
	NTR	NBR	ALCB / ALCC / ALCF	**ON**	*none*
	NTR	NBR	DDC	**ON**	*none*
	NTR	NBR	UBC	**ON**	*none*
	NTR	ZRB	none	**ON**	*Off*
	NTR	ZRB	DZP	**ON**	*none*
	PR7	NBR	none	**OFF**	*On*
Dimming Type	All	All	Any	**LINEAR**	*Logarithmic*
24V AUX	All	All	Any	**ON** (not Connected)	*none*
Scenes Data	All	All	Any	**0 (blank)**	*01-255*

*To program different settings, consult factory; RFD is required

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PSLED

Predator Small LED

PERFORMANCE DATA

Performance Package	Distribution	Input Watts	30K (3000K CCT, 70 CRI)		40K (4000K CCT, 70 CRI)		50K (5000K CCT, 70 CRI)		LLD @ 25°C		
			Lumens	LPW	Lumens	LPW	Lumens	LPW	50k Hours	75k Hours	100k Hours
P1	44	37	4,104	111	4,185	113	4,261	115	0.92	0.89	0.85
	45		5,481	148	5,589	151	5,690	154			
	55		5,622	152	5,733	155	5,837	158			
	65		5,319	144	5,424	147	5,522	149			
	66		5,553	150	5,662	153	5,764	156			
P2	44	52	5,472	105	5,579	107	5,680	109	0.92	0.89	0.85
	45		7,307	141	7,451	143	7,585	146			
	55		7,495	144	7,643	147	7,781	150			
	65		7,091	136	7,230	139	7,361	142			
	66		7,402	142	7,548	145	7,685	148			
P3	44	83	9,218	111	9,400	113	9,570	115	0.92	0.89	0.85
	45		12,310	148	12,552	151	12,779	154			
	55		12,627	152	12,876	155	13,109	158			
	65		11,945	144	12,181	147	12,401	149			
	66		12,471	150	12,716	153	12,946	156			
P4	44	123	13,219	107	13,480	110	13,724	112	0.92	0.89	0.85
	45		17,653	144	18,001	146	18,327	149			
	55		18,108	147	18,465	150	18,799	153			
	65		17,131	139	17,468	142	17,784	145			
	66		17,884	145	18,236	148	18,566	151			
P5	44	154	16,289	106	16,610	108	16,911	110	0.92	0.89	0.85
	45		21,753	141	22,181	144	22,583	147			
	55		22,314	145	22,753	148	23,165	150			
	65		21,109	137	21,525	140	21,914	142			
	66		22,037	143	22,471	146	22,878	149			
P6	44	201	20,366	101	20,768	103	21,143	105	0.92	0.89	0.85
	45		27,197	135	27,733	138	28,235	140			
	55		27,898	139	28,448	142	28,962	144			
	65		26,392	131	26,912	134	27,399	136			
	66		27,553	137	28,095	140	28,604	142			
P7	44	254	24,260	96	24,738	97	25,185	99	0.92	0.89	0.85
	45		32,397	128	33,035	130	33,632	132			
	55		33,232	131	33,886	133	34,499	136			
	65		31,438	124	32,057	126	32,637	128			
	66		32,820	129	33,467	132	34,072	134			

ELECTRICAL LOAD

Performance Package	Watts	Current (A)					
		120V	208V	240V	277V	347V	480V
P1	37	0.307	0.176	0.154	0.135	0.104	0.079
P2	52	0.417	0.238	0.207	0.18	0.143	0.105
P3	83	0.694	0.405	0.358	0.315	0.245	0.18
P4	123	0.995	0.574	0.501	0.442	0.349	0.254
P5	154	1.266	0.727	0.633	0.551	0.443	0.32
P6	201	1.69	0.96	0.84	0.74		
P7	254	2.31	1.33	1.15	0.999		

LUMINAIRE AMBIENT TEMPERATURE FACTOR

0°C	15°C	25°C	35°C	40°C
1.03	1.01	1.00	0.99	0.98

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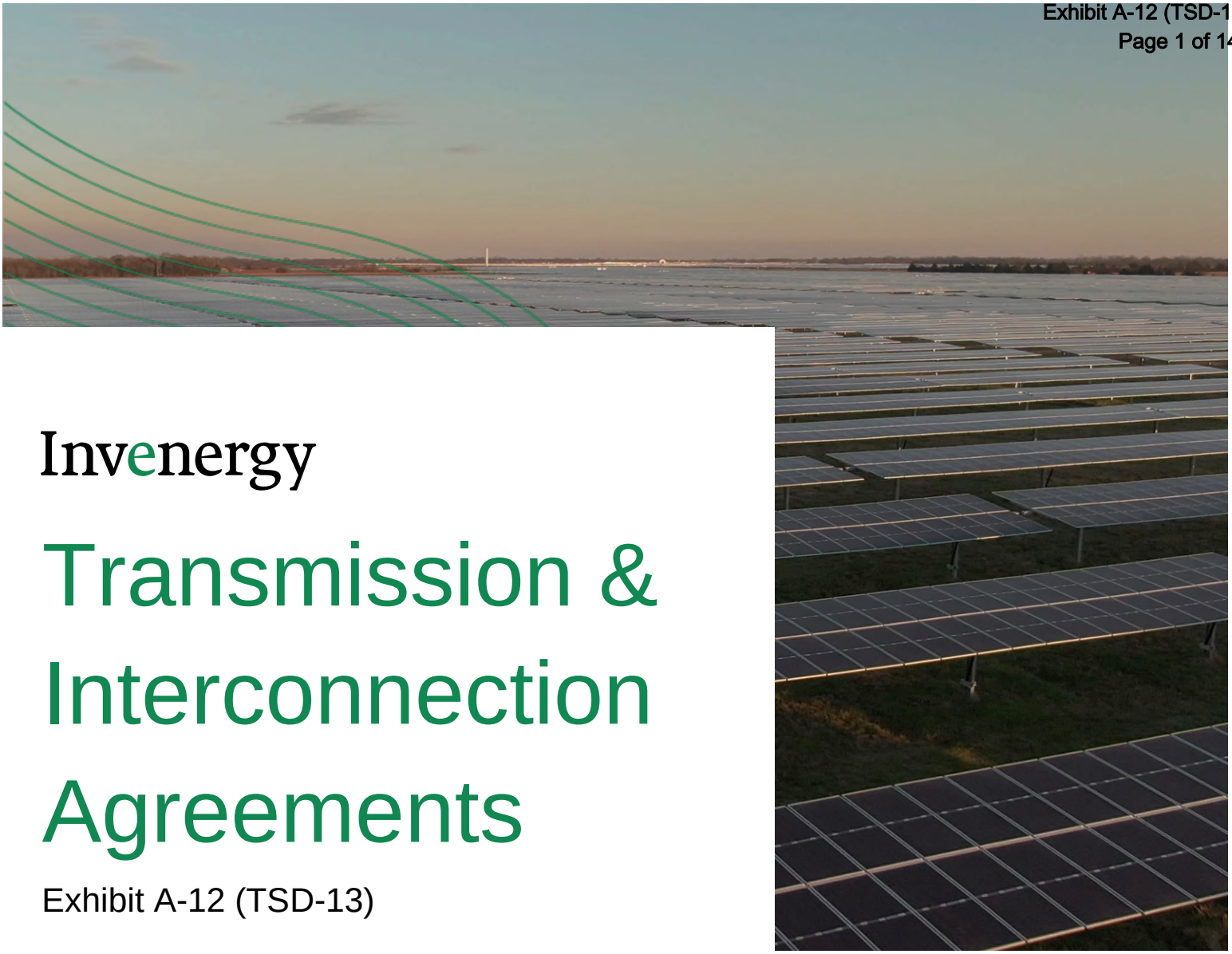

Invenergy

Transmission & Interconnection Agreements

Exhibit A-12 (TSD-13)

PREPARED FOR:

WASHTENAW SOLAR ENERGY LLC

Invenergy

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1.0 Transmission and Interconnection Agreements

1.1 Introduction

Washtenaw Solar Energy LLC ("Washtenaw Solar") 150 MW solar project (the "Project") will be constructed within the footprint of the Midcontinent Independent System Operator, Inc. ("MISO") regional transmission system. Washtenaw Solar already holds rights to interconnect into the transmission system and has secured its Point of Interconnection for the Project, as detailed below.

1.2 Queue Identifying Information

Washtenaw Solar's MISO queue number for the Project is J1062.

1.3 Generator Interconnection Agreement

On April 23, 2021, MISO, Washtenaw Solar and International Transmission Company d/b/a ITC*Transmission* ("ITC") executed a Generator Interconnection Agreement ("GIA"). A public version of the GIA is included as **Appendix A**. The GIA has been provided in lieu of feasibility and system impact studies, pursuant to the Filing Guidelines.

The GIA was set to lapse on December 31, 2026, and, due to Project delays related to the inability to secure local approval, the Project would not have been interconnected by that date. Accordingly, on February 26, 2025, Washtenaw Solar filed a Request for Waiver with the Federal Energy Regulatory Commission ("FERC"). On April 21, 2025, FERC granted the Request for Waiver, allowing for a 24-month extension of the GIA until December 31, 2028. A copy of FERC's order granting the waiver request is included as **Appendix B**.

Appendices

2.0 Appendices

Appendix A: Executed Generator Interconnection Agreement

SA 3650 ITC-WASHTENAW SOLAR GIA VERSION

EFFECTIVE 4/23/2021

ORIGINAL SERVICE AGREEMENT NO. 3650

PUBLIC VERSION

Project J1062

GENERATOR INTERCONNECTION AGREEMENT

entered into by the

Midcontinent Independent System Operator, Inc.,

Washtenaw Solar Energy LLC

And

International Transmission Company, dba ITC*Transmission*

GENERATOR INTERCONNECTION AGREEMENT (GIA)

THIS GENERATOR INTERCONNECTION AGREEMENT ("GIA") is made and entered into this 23rd day of April, 2021, by and between **Washtenaw Solar Energy LLC**, a limited liability company organized and existing under the laws of the State of Delaware ("Interconnection Customer" with a Generating Facility), and **International Transmission Company, dba ITC*Transmission***, a Michigan corporation organized and existing under the laws of the State of Michigan ("Transmission Owner"), and the **Midcontinent Independent System Operator, Inc**., a non-profit, non-stock corporation organized and existing under the laws of the State of Delaware ("Transmission Provider"). Interconnection Customer, Transmission Owner and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Transmission Provider has functional control of the operations of the Transmission System, as defined herein, and is responsible for providing Transmission Service and Interconnection Service on the transmission facilities under its control; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Generating Facility in Appendix A to this GIA; and

WHEREAS, Transmission Owner owns or operates the Transmission System, whose operations are subject to the functional control of Transmission Provider, to which Interconnection Customer desires to connect the Generating Facility, and may therefore be required to construct certain Interconnection Facilities and Network Upgrades, as set forth in this GIA; and

WHEREAS, Interconnection Customer, Transmission Owner and Transmission Provider have agreed to enter into this GIA, and where applicable subject to Appendix H for a provisional GIA, for the purpose of interconnecting the Generating Facility with the Transmission System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

ARTICLE 1. DEFINITIONS

When used in this GIA, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used. Those capitalized terms used in this GIA that are not otherwise defined in this GIA have the meaning set forth in the Tariff.

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric transmission or distribution system or the electric system associated with an Existing Generating Facility or of a higher queued Generating Facility, which is an electric system other than the Transmission Owner's Transmission System that is affected by the Interconnection Request. An Affected System may or may not be subject to FERC jurisdiction.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the Parties, their respective facilities and/or the respective services they provide.

Applicable Reliability Council shall mean the Regional Entity of NERC applicable to the Local Balancing Authority of the Transmission System to which the Generating Facility is directly interconnected.

Applicable Reliability Standards shall mean Reliability Standards approved by the Federal Energy Regulatory Commission (FERC) under section 215 of the Federal Power Act, as applicable.

Base Case shall mean the base case power flow, short circuit, and stability databases used for the Interconnection Studies by Transmission Provider or Interconnection Customer.

Breach shall mean the failure of a Party to perform or observe any material term or

condition of this GIA.

Breaching Party shall mean a Party that is in Breach of this GIA.

Business Day shall mean Monday through Friday, excluding Federal Holidays.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date (COD) of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to this GIA.

Common Use Upgrade (CUU) shall mean an Interconnection Facility, Network Upgrade, System Protection Facility, or any other classified addition, alteration, or improvement on the Transmission System or the transmission system of an Affected System, not classified under Attachment FF as a Baseline Reliability Project, Market Efficiency Project, or Multi-Value Project, that is needed for the interconnection of multiple Interconnection Customers' Generating Facilities and which is the shared responsibility of such Interconnection Customers.

Confidential Information shall mean any proprietary or commercially or competitively sensitive information, trade secret or information regarding a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, or any other information as specified in Article 22, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise, that is received by another Party.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of this GIA.

Definitive Planning Phase Queue Position shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, in the Definitive Planning Phase. The Definitive Planning Phase Queue Position is established based upon the date Interconnection Customer satisfies all of the requirements of Section 7.2 to enter the Definitive Planning Phase.

Demonstrated Capability shall mean the continuous net real power output that the Generating Facility is required to demonstrate in compliance with Applicable Reliability Standards.

Dispute Resolution shall mean the procedure for resolution of a dispute between or among the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Owner's facilities and equipment, or the Distribution System of another party that is interconnected with the Transmission Owner's Transmission System, if any, connected to the Transmission System, over which facilities Transmission Service or Wholesale Distribution Service under the Tariff is available at the time Interconnection Customer has requested interconnection of a Generating Facility for the purpose of either transmitting electric energy in interstate commerce or selling electric energy at wholesale in interstate commerce and which are used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among Local Balancing Authorities and other entities owning distribution facilities interconnected to the Transmission System.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the delivery service necessary to affect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which this GIA becomes effective upon execution by the Parties subject to acceptance by the Commission, or if filed unexecuted, upon the date specified by the Commission.

Emergency Condition shall mean a condition or situation: (1) that in the reasonable judgment of the Party making the claim is imminently likely to endanger, or is contributing to the endangerment of, life, property, or public health and safety; or (2) that, in the case of either Transmission Provider or Transmission Owner, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, Transmission Owner's Interconnection Facilities or the electric systems of others to which the Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and blackstart shall be considered Emergency Conditions; provided that Interconnection Customer is not obligated by this GIA to possess blackstart capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one of the enumerated conditions or situations identified in this definition also exists.

Energy Displacement Agreement shall mean an agreement between an Interconnection Customer with an Existing Generating Facility on the Transmission Provider's Transmission System and an Interconnection Customer with a proposed Generating Facility seeking to interconnect with Surplus Interconnection Service. The Energy Displacement Agreement specifies the term of operation, the Generating Facility Interconnection Service limit, and the mode of operation for energy production (common or singular operation).

Energy Resource Interconnection Service (ER Interconnection Service) shall mean

an Interconnection Service that allows Interconnection Customer to connect its Generating Facility to the Transmission System or Distribution System, as applicable, to be eligible to deliver the Generating Facility's electric output using the existing firm or non-firm capacity of the Transmission System on an as available basis. Energy Resource Interconnection Service does not convey transmission service.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes Transmission Owner to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Holiday shall mean a Federal Reserve Bank holiday for a Party that has its principal place of business in the United States and a Canadian Federal or Provincial banking holiday for a Party that has its principal place of business located in Canada.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a *et seq*.

FERC shall mean the Federal Energy Regulatory Commission, also known as Commission, or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device(s) for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities. A Generating Facility consists of one or more generating unit(s) and/or storage device(s) which usually can operate independently and be brought online or taken offline individually.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Generating Facility Modification shall mean modification to an Existing Generating Facility, including comparable replacement of only a portion of its equipment at the Existing Generating Facility.

Generating Facility Replacement shall mean replacement of one or more generating

units and/or storage devices at the Existing Generating Facility with one or more new generating units or storage devices at the same electrical Point of Interconnection as the generating units and/or storage devices that is/are being decommissioned and electrically disconnected.

Generator Interconnection Agreement (GIA) shall mean the form of interconnection agreement, set forth herein.

Generator Interconnection Procedures (GIP) shall mean the interconnection procedures set forth in Attachment X of the Tariff.

Generator Upgrades shall mean the additions, modifications, and upgrades to the electric system of an Existing Generating Facility or of a higher queued Generating Facility at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the Transmission Service necessary to affect Interconnection Customer's wholesale sale of electricity in interstate commerce.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, Transmission Owner, or any Affiliate thereof.

Group Study(ies) shall mean the process whereby more than one Interconnection Request is studied together, instead of serially, for the purpose of conducting one or more of the required Studies.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

HVDC Facilities shall mean the high voltage direct current transmission facilities,

including associated alternating current facilities, if any, that are subject to Section 27A of the Tariff and that are specifically identified in (i) any Agency Agreement pertaining to such facilities between Transmission Provider and Transmission Owner that owns or operates such facilities, or (ii) in any other arrangement that permits or will permit Transmission Provider to provide HVDC Service over such facilities as set forth in Section 27A of the Tariff.

HVDC Service shall mean Firm and Non-Firm Point-To-Point Transmission Service provided by Transmission Provider on HVDC Facilities pursuant to Section 27A of the Tariff.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date (ISD) shall mean the date upon which Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Owner's Interconnection Facilities to obtain backfeed power.

Interconnection Customer shall mean any entity, including Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission System.

Interconnection Customer's Interconnection Facilities (ICIF) shall mean all facilities and equipment, as identified in Appendix A of this GIA, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission System or Distribution System, as applicable. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean the Transmission Owner's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Facilities shall not include Distribution Upgrades, Generator Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by Transmission Provider, or its agent, for Interconnection Customer to determine a list of facilities (including Transmission Owner's Interconnection Facilities, System Protection Facilities, and if such upgrades have been determined, Network Upgrades, Distribution Upgrades, Generator Upgrades, Common Use Upgrades, and upgrades on Affected Systems, as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission System.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Generator Interconnection Procedures, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an Existing Generating Facility that is interconnected with the Transmission System.

Interconnection Service shall mean the service provided by Transmission Provider associated with interconnecting the Generating Facility to the Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of this GIA and, if applicable, the Tariff.

Interconnection Study (or Study) shall mean any of the studies described in the Generator Interconnection Procedures.

Interconnection Study Agreement shall mean the form of agreement contained in Attachment B to Appendix 1 of the Generator Interconnection procedures for conducting all studies required by the Generator Interconnection Procedures.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Generator Interconnection Procedures.

IRS shall mean the Internal Revenue Service.

Local Balancing Authority shall mean an operational entity or a Joint Registration Organization which is (i) responsible for compliance with the subset of NERC Balancing Authority Reliability Standards defined in the Balancing Authority Agreement for their local area within the MISO Balancing Authority Area, (ii) a Party to Balancing Authority Agreement, excluding MISO, and (iii) provided in the Balancing Authority Agreement.

Loss shall mean any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under this GIA on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing, by the indemnified party.

Material Modification shall mean: (1) modification to an Interconnection Request in the queue, that has a material adverse impact on the cost or timing of any other Interconnection Request with a later queue priority date; or (2) planned modification to an Existing Generating Facility, that is undergoing evaluation for a Generating Facility Modification or Generating Facility Replacement, and has a material adverse impact on the Transmission System with

respect to: i) steady-state thermal or voltage limits, ii) dynamic system stability and response, or iii) short-circuit capability limit; compared to the impacts of the Existing Generating Facility prior to the modification or replacement.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to this GIA at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

Monitoring and Consent Agreement shall mean an agreement that defines the terms and conditions applicable to a Generating Facility acquiring Surplus Interconnection Service. The Monitoring and Consent Agreement will list the roles and responsibilities of an Interconnection Customer seeking to interconnect with Surplus Interconnection Service and Transmission Owner to maintain the total output of the Generating Facility inside the parameters delineated in the GIA.

NERC shall mean the North American Electric Reliability Corporation or its successor organization.

Network Customer shall have that meaning as provided in the Tariff.

Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service (NR Interconnection Service) shall mean an Interconnection Service that allows Interconnection Customer to integrate its Generating Facility with the Transmission System in the same manner as for any Generating Facility being designated as a Network Resource. Network Resource Interconnection Service does not convey transmission service. Network Resource Interconnection Service shall include any network resource interconnection service established under an agreement with, or the tariff of, a Transmission Owner prior to integration into MISO, that is determined to be deliverable through the integration deliverability study process.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission System or Distribution System, as applicable, to accommodate the interconnection of the Generating Facility to the Transmission System. Network Upgrade shall not include any HVDC Facility Upgrades.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with this GIA or its performance.

Operating Horizon Study shall mean an Interconnection System Impact Study that includes in service transmission and generation for an identified timeframe to determine either

the available injection capacity of an Interconnection Request or Interconnection Facilities and/or Transmission System changes required for the requested Interconnection Service**.**

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Generator Interconnection Procedures for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer, or any combination of the above.

Planning Horizon Study shall mean an Interconnection System Impact Study that includes a future year study to determine either the available injection capacity of an Interconnection Request or Interconnection Facilities and/or Transmission System changes required for the requested Interconnection Service.

Point of Change of Ownership (PCO) shall mean the point, as set forth in Appendix A to the Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Owner's Interconnection Facilities.

Point of Interconnection (POI) shall mean the point, as set forth in Appendix A of the GIA, where the Interconnection Facilities connect to the Transmission System.

Provisional Interconnection Service shall mean interconnection service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling that Transmission System to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Provisional Generator Interconnection Agreement and the Tariff.

Provisional Interconnection Study shall mean an engineering study, performed at Interconnection Customer's request, as a condition to entering into a provisional GIA, that evaluates the impact of the proposed interconnection on the safety and reliability of the Transmission System and, if applicable, any Affected System. The study shall identify and detail the impacts on the Transmission System and, if applicable, an Affected System, from stability, short circuit, and voltage issues that would result if the Generating Facility were interconnected without project modifications or system modifications.

Provisional Generator Interconnection Agreement shall mean the interconnection agreement for Provisional Interconnection Service established between the Transmission Provider and/or the Transmission Owner and the Interconnection Customer as set forth in Section 7.9 of this Attachment X. This agreement shall take the form of the Generator Interconnection Agreement modified for provisional purposes.

Queue Position shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests. The Queue Position is established based upon the date and time of receipt of the valid Interconnection Request by Transmission Provider.

Reasonable Efforts shall have that meaning as provided in the Tariff.

Replacement Generating Facility shall mean a Generating Facility that replaces an Existing Generating Facility, or a portion thereof, at the same electrical Point of Interconnection pursuant to Section 3.7 of this Attachment X.

Scoping Meeting shall mean the meeting between representatives of Interconnection Customer, Transmission Owner, Affected System Operator(s) and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Shared Network Upgrade shall mean a Network Upgrade or Common Use Upgrade that is funded by an Interconnection Customer(s), including when the Transmission Owner elects to fund the capital cost of such a Network Upgrade or Common Use Upgrade under Section 11.3 of the GIA, and also benefits other Interconnection Customer(s) that are later identified as beneficiaries.

Site Control shall mean a documented right for one or more parcels of land for the purpose of constructing a Generating Facility, Interconnection Customer's Interconnection Facilities, and, if applicable (*i.e.*, when the Interconnection Customer is providing the site for such facilities), the Transmission Owner's Interconnection Facilities and Network Upgrades at the POI that the Interconnection Customer will develop. Such documented right shall be one of the following: (1) ownership of a site; (2) a leasehold interest in a site; or (3) an option to purchase or acquire a leasehold interest in a site; or (4) any other contractual or legal right to possess or occupy a site.

Small Generating Facility shall mean a Generating Facility that has an aggregate net Generating Facility Capacity of no more than five MW and meets the requirements of Section 14 and Appendix 3 of the GIP.

Special Protection System (SPS) shall mean an automatic protection system or remedial action scheme designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components, to maintain system reliability. Such action may include changes in demand (MW and MVar), energy (MWh and MVarh), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding, (b) fault conditions that must be isolated, (c) out-of-step relaying not designed as an integral part of an SPS, or (d) Transmission Control Devices.

Stand Alone Network Upgrades shall mean Network Upgrades, that are not part of an

Affected System that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Transmission Provider, Transmission Owner and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to this GIA. If the Transmission Provider or Transmission Owner and Interconnection Customer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, the Transmission Provider or Transmission Owner that disagrees with the Interconnection Customer must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider or Transmission Owner does not consider the Network Upgrade to be a Stand Alone Network Upgrade within 15 days of its determination.

Surplus Interconnection Service shall mean any Interconnection Service that is derived from the unneeded portion of Interconnection Service established in a GIA or in agreement with, or under the tariff of, a Transmission Owner prior to integration into MISO, such that if Surplus Interconnection Service is utilized the total amount of Interconnection Service at the Point of Interconnection would remain the same.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission System or other delivery systems or other generating systems from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission System or on other delivery systems or other generating systems to which the Transmission System is directly connected.

Tariff shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with the Commission, and as amended or supplemented from time to time, or any successor tariff.

Transmission Control Devices shall mean a generally accepted transmission device that is planned and designed to provide dynamic control of electric system quantities, and are usually employed as solutions to specific system performance issues. Examples of such devices include fast valving, high response exciters, high voltage DC links, active or real power flow control and reactive compensation devices using power electronics (*e.g.*, unified power flow controllers), static var compensators, thyristor controlled series capacitors, braking resistors, and in some cases mechanically-switched capacitors and reactors. In general, such systems are not considered to be Special Protection Systems.

Transmission Owner shall mean that Transmission Owner as defined in the Tariff, which includes an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at which Interconnection Customer proposes to interconnect or otherwise integrate the operation of the Generating Facility. Transmission Owner should be read to include any Independent Transmission Company that manages the transmission facilities of Transmission Owner and shall include, as applicable, the owner and/or operator of distribution facilities interconnected to the Transmission System, over which facilities transmission service or Wholesale Distribution Service under the Tariff is available at the time Interconnection Customer requests Interconnection Service and to which Interconnection Customer has requested

interconnection of a Generating Facility for the purpose of either transmitting electric energy in interstate commerce or selling electric energy at wholesale in interstate commerce.

Transmission Provider shall mean the Midcontinent Independent System Operator, Inc. ("MISO"), the Regional Transmission Organization that controls or operates the transmission facilities of its transmission-owning members used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff.

Transmission Owner's Interconnection Facilities (TOIF) shall mean all facilities and equipment owned by Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to this GIA, including any modifications, additions or upgrades to such facilities and equipment. Transmission Owner's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Generator Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Transmission System shall mean the facilities owned by Transmission Owner and controlled or operated by Transmission Provider or Transmission Owner that are used to provide Transmission Service (including HVDC Service) or Wholesale Distribution Service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Variable Energy Resource shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

Wholesale Distribution Service shall have that meaning as provided in the Tariff. Wherever the term "transmission delivery service" is used, Wholesale Distribution Service shall also be implied.

ARTICLE 2. EFFECTIVE DATE, TERM AND TERMINATION

2.1 **Effective Date**. This GIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC. Transmission Provider shall promptly file this GIA with FERC upon execution in accordance with Article 3.1, if required.

2.2 **Term of Agreement**. Subject to the provisions of Article 2.3, this GIA shall remain in effect for a period of 30 years from the Effective Date and shall be automatically renewed for each successive one-year period thereafter on the anniversary of the Effective Date.

2.3 **Termination Procedures.** This GIA may be terminated as follows:

2.3.1 **Written Notice.** This GIA may be terminated by Interconnection Customer after giving Transmission Provider and Transmission Owner ninety (90) Calendar Days advance written notice. This GIA shall be terminated by Transmission Provider if the Generating Facility or a portion of the Generating Facility fails to achieve Commercial Operation by the Commercial Operation Date established in accordance with Section 4.4.4 of Attachment X, including any extension provided thereunder, or has ceased Commercial Operation for three (3) consecutive years, beginning with the last date of Commercial Operation for the Generating Facility, after giving Interconnection Customer ninety (90) Calendar Days advance written notice. Where only a portion of the Generating Facility fails to achieve Commercial Operation by the Commercial Operation Date established in accordance with Section 4.4.4 of Attachment X, including any extension provided thereunder, Transmission Provider shall only terminate that portion of the GIA. Notwithstanding the foregoing, in the limited circumstance that the Interconnection Request is served by a contingent Network Upgrade with an in-service date that is farther out than the Commercial Operation Date permitted under Section 4.4.4 of Attachment X, Transmission Provider shall only terminate this GIA for failure to achieve Commercial Operation by that later in-service date of the contingent Network Upgrade. The Generating Facility will not be deemed to have ceased Commercial Operation for purposes of this Article 2.3.1 if Interconnection Customer can document that it has taken other significant steps to maintain or restore operational readiness of the Generating Facility for the purpose of returning the Generating Facility to Commercial Operation as soon as possible.

2.3.1.1 **Surplus Interconnection Service.** Where this GIA provides for Surplus Interconnection Service and the Energy Displacement Agreement or the Monitoring and Consent Agreement required for Surplus Interconnection Service are no longer in effect, Interconnection Customer shall immediately cease Commercial Operation of the Generating Facility and this GIA shall be deemed terminated. In the event that the Existing Generating Facility retires and/or permanently ceases commercial operation, the Surplus Interconnection Service provided under this GIA

shall terminate except as provided in Section 3.3.1.3 of the GIP.

2.3.2 **Default.** Any Party may terminate this GIA in accordance with Article 17.

2.3.3 Notwithstanding Articles 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this GIA, if required, which notice has been accepted for filing by FERC.

2.4 **Termination Costs.** If a Party elects to terminate this GIA pursuant to Article 2.3 above, each Party shall pay all costs incurred for which that Party is responsible (including any cancellation costs relating to orders or contracts for Interconnection Facilities, applicable upgrades, and related equipment) or charges assessed by the other Parties, as of the date of the other Parties' receipt of such notice of termination, under this GIA. In the event that this GIA is terminated by Interconnection Customer, Interconnection Customer is responsible for all financial impact that is caused as a result of this termination or the termination of Interconnection Customer's FCA(s) or MPFCA(s), such financial impact being determined through the financial impact analysis performed in accordance with Section 7.8 of Attachment X. In the event of termination by a Party, the Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this GIA, unless otherwise ordered or approved by FERC:

2.4.1 With respect to any portion of the Transmission Owner's Interconnection Facilities, Network Upgrades, System Protection Facilities, Distribution Upgrades, Generator Upgrades, and if so determined and made a part of this GIA, upgrades on Affected Systems, that have not yet been constructed or installed, Transmission Owner shall to the extent possible and to the extent of Interconnection Customer's written notice under Article 2.3.1, cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and Transmission Owner shall deliver such material and equipment, and, if necessary, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Transmission Owner for any or all such costs of materials or equipment not taken by Interconnection Customer or upgrades not yet constructed, Transmission Owner shall promptly transfer such amounts to Transmission Provider, less any costs, including penalties incurred by Transmission Owner to cancel any pending orders of or return such materials, equipment, or contracts. Transmission Provider will perform a financial impact analysis in accordance with Section 7.8 of Attachment X to determine the amount that should be refunded to Interconnection Customer. Transmission Provider shall refund such remaining amounts to Interconnection Customer, less any financial

impact caused by the termination of this GIA or Interconnection Customer's FCA(s) or MPFCA(s), as determined through the analysis performed in accordance with Section 7.8 of Attachment X. If Interconnection Customer made its payment(s) through a letter of credit, surety bond, or parental guarantee, Transmission Owner will draw against that letter of credit, surety bond, or parental guarantee in an amount determined through the analysis performed in accordance with Section 7.8 of Attachment X, and transfer that amount to Transmission Provider, unless Interconnection Customer funds the financial impact through another means.

If an Interconnection Customer terminates this GIA, it shall be responsible for all costs incurred in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment, and other expenses including any upgrades or related equipment for which Transmission Owner has incurred expenses and has not been reimbursed by Interconnection Customer.

2.4.2 Transmission Owner may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Owner shall be responsible for all costs associated with procuring such materials, equipment, or facilities. If Transmission Owner does not so elect, then Interconnection Customer shall be responsible for such costs.

2.4.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this GIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation, reconfiguration or other disposition or retirement of such materials, equipment, or facilities, and such other expenses actually incurred by Transmission Owner necessary to return the Transmission, Distribution or Generator System, as applicable, to safe and reliable operation.

2.5 **Disconnection**. Upon termination of this GIA, the Parties will take all appropriate steps to disconnect the Generating Facility from the Transmission or Distribution System, as applicable. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this GIA or such non-terminating Party otherwise is responsible for these costs under this GIA.

2.6 **Survival.** This GIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this GIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this GIA was in effect; and to permit each Party to have access to the lands of the other Party pursuant to this GIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

ARTICLE 3. REGULATORY FILINGS

3.1 **Filing.** Transmission Provider shall file this GIA (and any amendment hereto) with the appropriate Governmental Authority, if required. A Party may request that any information so provided be subject to the confidentiality provisions of Article 22. If that Party has executed this GIA, or any amendment thereto, the Party shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

ARTICLE 4. SCOPE OF SERVICE

4.1 **Interconnection Product Options**. Interconnection Customer has selected the following (checked) type of Interconnection Service:

Check: _____ NZ or ____ ER and/or _X__ NR (See Appendix A for details)

4.1.1 Energy Resource Interconnection Service (ER Interconnection Service).

4.1.1.1 The Product. ER Interconnection Service allows Interconnection Customer to connect the Generating Facility to the Transmission or Distribution System, as applicable, and be eligible to deliver the Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive ER Interconnection Service, Transmission Owner shall construct facilities consistent with the studies identified in Appendix A.

An Interconnection Customer seeking ER Interconnection Service for new or added capacity at a Generating Facility may be granted conditional ER Interconnection Service status to the extent there is such capacity available on the Transmission System to accommodate the Interconnection Customer's Generating Facility. At the request of Interconnection Customer, conditional ER Interconnection Service status may be granted subject to the system being able to accommodate the interconnection without upgrades, until such time as a higher queued project(s) with a later service date affecting the same common elements is placed into service. The conditional ER Interconnection Service shall be terminated in the event Interconnection Customer fails to fund the necessary studies and the Network Upgrades necessary to grant the Interconnection Customer's ER Interconnection Service upon the completion of higher queued projects involving the same common elements.

4.1.1.2 Transmission Delivery Service Implications. Under ER Interconnection Service, Interconnection Customer will be eligible to inject power from

the Generating Facility into and deliver power across the Transmission System on an "as available" basis up to the amount of MW identified in the applicable stability and steady state studies to the extent the upgrades initially required to qualify for ER Interconnection Service have been constructed. After that date FERC makes effective MISO's Energy Market Tariff filed in Docket No. ER04-691-000, Interconnection Customer may place a bid to sell into the market up to the maximum identified Generating Facility output, subject to any conditions specified in the Interconnection Service approval, and the Generating Facility will be dispatched to the extent the Interconnection Customer's bid clears. In all other instances, no transmission or other delivery service from the Generating Facility is assured, but Interconnection Customer may obtain Point-To-Point Transmission Service, Network Integration Transmission Service or be used for secondary network transmission service, pursuant to the Tariff, up to the maximum output identified in the stability and steady state studies. In those instances, in order for Interconnection Customer to obtain the right to deliver or inject energy beyond the Point of Interconnection or to improve its ability to do so, transmission delivery service must be obtained pursuant to the provisions of the Tariff. The Interconnection Customer's ability to inject its Generating Facility output beyond the Point of Interconnection, therefore, will depend on the existing capacity of the Transmission or Distribution System as applicable, at such time as a Transmission Service request is made that would accommodate such delivery. The provision of Firm Point-To-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network or Distribution Upgrades.

4.1.2 Network Resource Interconnection Service (NR Interconnection Service).

4.1.2.1 The Product. Transmission Provider must conduct the necessary studies and Transmission Owner shall construct the facilities identified in Appendix A of this GIA, subject to the approval of Governmental Authorities, needed to integrate the Generating Facility in the same manner as for any Generating Facility being designated as a Network Resource.

4.1.2.2 Transmission Delivery Service Implications. NR Interconnection Service allows the Generating Facility to be designated by any Network Customer under the Tariff on the Transmission System as a Network Resource, up to the Generating Facility's full output, on the same basis as existing Network Resources that are interconnected to the Transmission or Distribution System, as applicable, and to be studied as a Network Resource on the assumption that such a designation will occur. Although NR Interconnection Service does not convey a reservation of Transmission Service, any Network Customer can utilize Network Integration Transmission Service under the Tariff to obtain delivery of

energy from the Generating Facility in the same manner as it accesses Network Resources. A Generating Facility receiving NR Interconnection Service may also be used to provide Ancillary Services after technical studies and/or periodic analyses are performed with respect to the Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Network Resource. However, if the Generating Facility has not been designated as a Network Resource by any Network Customer, it cannot be required to provide Ancillary Services except to the extent such requirements extend to all generating facilities that are similarly situated. The provision of Network Integration Transmission Service or Firm Point-To-Point Transmission Service may require additional studies and the construction of additional upgrades. Because such studies and upgrades would be associated with a request for delivery service under the Tariff, cost responsibility for the studies and upgrades would be in accordance with FERC's policy for pricing transmission delivery services.

NR Interconnection Service does not necessarily provide Interconnection Customer with the capability to physically deliver the output of its Generating Facility to any particular load on the Transmission System without incurring congestion costs. In the event of transmission or distribution constraints on the Transmission or Distribution System, as applicable, the Generating Facility shall be subject to the applicable congestion management procedures in the Transmission System in the same manner as Network Resources.

There is no requirement either at the time of study or interconnection, or at any point in the future, that the Generating Facility be designated as a Network Resource by a Network Customer or that Interconnection Customer identify a specific buyer (or sink). To the extent a Network Customer does designate the Generating Facility as a Network Resource, it must do so pursuant to the Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining NR Interconnection Service, any future Transmission Service request for delivery from the Generating Facility within the Transmission System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional studies be performed or that any further upgrades associated with such Generating Facility be undertaken, regardless of whether such Generating Facility is ever designated by a Network Customer as a Network Resource and regardless of changes in ownership of the Generating Facility. To the extent Interconnection Customer enters into an arrangement for long term Transmission Service for deliveries from the Generating Facility to customers other than the studied Network Customers, or for any Point-To-Point Transmission

Service, such request may require additional studies and upgrades in order for Transmission Provider to grant such request. However, the reduction or elimination of congestion or redispatch costs may require additional studies and the construction of additional upgrades.

To the extent Interconnection Customer enters into an arrangement for long term Transmission Service for deliveries from the Generating Facility outside the Transmission System, such request may require additional studies and upgrades in order for Transmission Provider to grant such request.

4.1.2.3 Conditional NR Interconnection Service. An Interconnection Customer seeking NR Interconnection Service for new or added capacity at a Generating Facility may be granted conditional NR Interconnection Service status to the extent there is such capacity available on the Transmission System to accommodate the Interconnection Customer's Generating Facility. At the request of Interconnection Customer, conditional NR Interconnection Service status may be granted subject to the system being able to accommodate the interconnection without upgrades, until such time as higher queued project(s) with a later service date affecting the same common elements is placed into service. The conditional NR Interconnection Service status may be converted to ER Interconnection Service if either of the following occurs:

1) Interconnection Customer fails to fund necessary studies and Network Upgrades required to allow the Interconnection Customer's Generating Facility to receive NR Interconnection Service upon the completion of higher queued projects involving the same common elements; or

2) The higher queued project(s) or planned and required Network Upgrades are placed in service and the Network Upgrades required to provide NR Interconnection Service status to the Interconnection Customer's Generating Facility are not in service.

In the event Interconnection Customer fails to fund the necessary studies and Network Upgrades for NR Interconnection Service, the Interconnection Customer's conditional NR Interconnection Service status shall be converted to ER Interconnection Service status unless Interconnection Customer makes a new Interconnection Request. Such new Interconnection Request shall be evaluated in accordance with the GIP and its new queue position.

Some or all of the conditional NR Interconnection Service status may be temporarily revoked if the Network Upgrades are not in service when the higher queued project(s) are placed in service. The availability of

conditional NR Interconnection Service status will be determined by Transmission Provider's studies. Upon funding and completion of the Network Upgrades required to establish the Generating Facility's NR Interconnection Service status, the Generating Facility will be granted NR Interconnection Service status.

The Parties agree that the portion of the Generating Facility classified as NR Interconnection Service is the first portion of the output of the combined output of all the units at the Generating Facility except in circumstances where Interconnection Customer otherwise elects this GIA, as amended, to allocate that portion to the output of specific unit(s) at the Generating Facility, the total of which will not exceed the output eligible for NR Interconnection Service as shown by the additional studies. To the extent Interconnection Customer desires to obtain NR Interconnection Service for any portion of the Generating Facility in addition to that supported by such additional studies, Interconnection Customer will be required to request such additional NR Interconnection Service through a separate Interconnection Request in accordance with the GIP.

4.1.3 Surplus Interconnection Service.

4.1.3.1 The Product. Surplus Interconnection Service is restricted Interconnection Service that allows an Interconnection Customer to increase the gross generating capability at the same Point of Interconnection of an Existing Generating Facility without increasing the total amount of Interconnection Service at the Point of Interconnection.

4.1.3.2 Transmission Delivery Service Implications. Surplus Interconnection Service does not convey any right to deliver electricity to any specific customer or Point of Delivery.

4.2 Provision of Service. Transmission Provider shall provide Interconnection Service for the Generating Facility at the Point of Interconnection.

4.3 Performance Standards. Each Party shall perform all of its obligations under this GIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice. To the extent a Party is required or prevented or limited in taking any action by such regulations and standards, or if the obligations of any Party may become limited by a change in Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice after the execution of this GIA, that Party shall not be deemed to be in Breach of this GIA for its compliance therewith. The Party so limited shall notify the other Parties whereupon Transmission Provider shall amend this GIA in concurrence with the other Parties and submit the amendment to the Commission for approval.

4.4 No Transmission Delivery Service. The execution of this GIA does not constitute a

request for, or the provision of, any transmission delivery service under the Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

4.5 Interconnection Customer Provided Services. The services provided by Interconnection Customer under this GIA are set forth in Article 9.6 and Article 13.4.1. Interconnection Customer shall be paid for such services in accordance with Article 11.7.

ARTICLE 5. INTERCONNECTION FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

5.1 Options. Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select: 1) the In-Service Date, Initial Synchronization Date, and Commercial Operation Date based on a reasonable construction schedule that will allow sufficient time for design, construction, equipment procurement, and permit acquisition of Transmission System equipment or right-of-way; and 2) either the Standard Option or Alternate Option set forth below and such dates and selected option shall be set forth in Appendix B. At the same time, Interconnection Customer shall indicate whether it elects to exercise the Option to Build set forth in Article 5.1.3 below. If the dates designated by Interconnection Customer are not acceptable to Transmission Owner, Transmission Owner shall so notify Interconnection Customer within thirty (30) Calendar Days. Upon receipt of the notification that Interconnection Customer's designated dates are not acceptable to Transmission Owner, the Interconnection Customer shall notify Transmission Owner within thirty (30) Calendar Days whether it elects to exercise the Option to Build if it has not already elected to exercise the Option to Build.

5.1.1 Standard Option. Transmission Owner shall design, procure, and construct the Transmission Owner's Interconnection Facilities, Network Upgrades, System Protection Facilities, Distribution Upgrades, and Generator Upgrades using Reasonable Efforts to complete the Transmission Owner's Interconnection Facilities, Network Upgrades, System Protection Facilities, Distribution Upgrades and Generator Upgrades by the dates set forth in Appendix B, Milestones, subject to the receipt of all approvals required from Governmental Authorities and the receipt of all land rights necessary to commence construction of such facilities, and such other permits or authorizations as may be required. Transmission Provider or Transmission Owner shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, Applicable Laws and Regulations and Good Utility Practice. In the event Transmission Owner reasonably expects that it will not be able to complete the Transmission Owner's Interconnection Facilities, Network Upgrades, System Protection Facilities, Distribution Upgrades and Generator Upgrades by the specified dates, Transmission Owner shall promptly provide written notice to Interconnection Customer and Transmission Provider and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 Alternate Option. If the dates designated by Interconnection Customer are acceptable to Transmission Provider and Transmission Owner, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days, and Transmission Owner shall assume responsibility for the design, procurement and construction of the Transmission Owner's Interconnection Facilities by the designated dates.

If Transmission Owner subsequently fails to complete the Transmission Owner's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to complete Network Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Appendix B, Milestones; Transmission Owner shall pay Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by Interconnection Customer shall be extended day for day for each Calendar Day that Transmission Provider refuses to grant clearances to install equipment.

Transmission Owner and Interconnection Customer may adopt an incentive payment schedule that is mutually agreeable to encourage Transmission Owner to meet specified accelerated dates. Such payment by Interconnection Customer is not subject to refund.

5.1.3 Option to Build. Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades by the dates originally designated by Interconnection Customer under Article 5.1.2. The Parties must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 Negotiated Option. If the dates designated by Interconnection Customer pursuant to Article 5.1 are not acceptable to Transmission Owner, the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives, or the procurement and construction of all facilities other than Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects to exercise the Option to Build under Article 5.1.3). If the Parties are unable to reach agreement on such terms and conditions, then, pursuant to Article 5.1.1 (Standard Option), Transmission Owner shall assume responsibility for the design, procurement and construction of all facilities other than Transmission Owner's Interconnection Facilities and Stand Alone

Network Upgrades if the Interconnection Customer elects to exercise the Option to Build.

Transmission Owner and Interconnection Customer may adopt an incentive payment schedule that is mutually agreeable to encourage Transmission Owner to meet specified accelerated dates. Such payment by Interconnection Customer is not subject to refund.

5.2 General Conditions Applicable to Option to Build. If Interconnection Customer assumes responsibility for the design, procurement and construction of the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades after receipt of all required approvals from Governmental Authorities necessary to commence construction,

(1) Interconnection Customer shall engineer, procure equipment, and construct the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Owner, or as required by any Governmental Authority;

(2) Interconnection Customer's engineering, procurement and construction of the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law or Governmental Authority to which Transmission Owner would be subject in the engineering, procurement or construction of the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Transmission Provider, at Transmission Provider's option, and Transmission Owner shall be entitled to review and approve the engineering design, equipment acceptance tests(including witnessing of acceptance tests), and the construction (including monitoring of construction) of the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades, and shall have the right to reject any design, procurement, construction or acceptance test of any equipment that does not meet the standards and specifications of Transmission Provider, Transmission Owner and any Governmental Authority;

(4) prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider and Transmission Owner a schedule for construction of the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Transmission Provider and Transmission Owner;

(5) at any time during construction, Transmission Provider and Transmission Owner shall have unrestricted access to the construction site for the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) at any time during construction, should any phase of the engineering, equipment procurement, or construction of the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Owner, Interconnection Customer shall be obligated to remedy deficiencies in that portion of the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to meet the standards and specifications provided by Transmission Provider and Transmission Owner;

(7) Interconnection Customer shall indemnify Transmission Provider and Transmission Owner for claims arising from the Interconnection Customer's construction of the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1, Indemnity;

(8) Interconnection Customer shall transfer control of the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Owner;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Owner in accordance with Appendix B;

(10) Transmission Provider, at Transmission Provider's option, and Transmission Owner shall approve and accept for operation and maintenance the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2 only if the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades meet the standards and specifications of Transmission Provider, Transmission Owner and any Governmental Authority.

(11) Interconnection Customer shall deliver to Transmission Owner "as-built" drawings, information, and any other documents that are reasonably required by Transmission Owner to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by Transmission Owner.

(12) If Interconnection Customer exercises the Option to Build pursuant to Article 5.1.3, Interconnection Customer shall pay Transmission Owner the agreed upon amount of [$ PLACEHOLDER] for Transmission Owner to execute the responsibilities enumerated to Transmission Owner under Article 5.2. Transmission Owner shall invoice Interconnection Customer for this total amount to be divided on a monthly basis pursuant to Article 12.

(13) If Interconnection Customer exercises the Option to Build pursuant to Article 5.1.3, and the Transmission Owner has elected to fund the costs of Network Upgrades pursuant to Article 11.3, then prior to Interconnection Customer incurring any construction costs relating to the Option to Build and by the date specified in Appendix B, Interconnection Customer shall invoice the Transmission Owner for the estimated amount to be expended by the Interconnection Customer to construct any Stand Alone Network Upgrades for which the Interconnection Customer has exercised its Option to Build in accordance with Appendix B. The Transmission Owner shall be required to reimburse Interconnection Customer for the full amount of such invoiced costs by the date specified in Appendix B, which shall be prior to the date by which Interconnection Customer must make any construction payment for such Stand Alone Network Upgrades. After completion of the construction of Stand Alone Network Upgrades by the Interconnection Customer and by the date specified in Appendix B for the Interconnection Customer to transfer such Stand Alone Network Upgrades to the Transmission Owner, Interconnection Customer shall provide an invoice of the final cost of the construction of Stand Alone Upgrades and shall set forth such costs in sufficient detail to enable the Transmission Owner to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. In the event that the actual costs exceed the estimated costs previously invoiced by Interconnection Customer and paid by Transmission Owner, Transmission Owner shall pay to Interconnection Customer the difference between the amount previously paid and the actual costs within thirty (30) Calendar Days after receipt of a final construction invoice from Interconnection Customer. In the event that the actual costs are less than the estimated costs previously invoiced by Interconnection Customer and paid by Transmission Owner, Interconnection Customer shall refund, with interest (calculated in accordance with 18 C.F.R. Section 35.19a(a)(2)(iii), to Transmission Owner any amount by which the actual payment by Transmission Owner for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice. Following the transfer of the Stand Alone Network Upgrades from the Interconnection Customer to the Transmission Owner, the Interconnection Customer shall make payments for such facilities to the Transmission Owner pursuant to an agreement between and among the Parties.

5.3 **Liquidated Damages**. The actual damages to Interconnection Customer, in the event the Transmission Owner's Interconnection Facilities or Network Upgrades are not completed by the dates designated by Interconnection Customer and accepted by Transmission Provider and Transmission Owner pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by Transmission Owner to Interconnection Customer in the event that Transmission Owner does not complete any portion of the Transmission Owner's Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost

of the Transmission Owner's Interconnection Facilities and Network Upgrades, in the aggregate, for which Transmission Owner has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of the Transmission Owner's Interconnection Facilities and Network Upgrades for which Transmission Owner has assumed responsibility to design, procure, and construct. The foregoing payments will be made by Transmission Owner to Interconnection Customer as just compensation for the damages caused to Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this GIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Transmission Owner's failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of the Transmission Owner's Interconnection Facilities or Network Upgrades to take the delivery of power for the Generating Facility's Trial Operation or to export power from the Generating Facility on the specified dates, unless Interconnection Customer would have been able to commence use of the Transmission Owner's Interconnection Facilities or Network Upgrades to take the delivery of power for Generating Facility's Trial Operation or to export power from the Generating Facility, but for Transmission Owner's delay; (2) the Transmission Owner's failure to meet the specified dates is the result of the action or inaction of Transmission Provider, Interconnection Customer or any other earlier queued Interconnection Customer who has entered into an earlier GIA with Transmission Provider and/or a Transmission Owner or with an Affected System Operator, or any cause beyond Transmission Owner's reasonable control or reasonable ability to cure;
(3) Interconnection Customer has assumed responsibility for the design, procurement and construction of the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades; (4) the delay is due to the inability of Transmission Owner to obtain all required approvals from Governmental Authorities in a timely manner for the construction of any element of the Interconnection Facilities, Network Upgrades or Stand Alone Network Upgrades, or any other permit or authorization required, or any land rights or other private authorizations that may be required, and Transmission Owner has exercised Reasonable Efforts in procuring such approvals, permits, rights or authorizations; or (5) the Parties have otherwise agreed.

5.4 **Power System Stabilizers.** Interconnection Customer shall procure, install, maintain and operate power system stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council. Transmission Provider and Transmission Owner reserve the right to reasonably establish minimum acceptable settings for any installed power system stabilizers, subject to the design and operating limitations of the Generating Facility. If the Generating Facility's power system stabilizers are removed from service or are not capable of automatic operation, Interconnection Customer shall immediately notify the Transmission Provider's system operator, or its designated representative. The requirements of this paragraph shall not

apply to induction generators.

5.5 **Equipment Procurement.** If responsibility for construction of the Transmission Owner's Interconnection Facilities, Network Upgrades and/or Distribution Upgrades is to be borne by Transmission Owner, then Transmission Owner shall commence design of the Transmission Owner's Interconnection Facilities, Network Upgrades and/or Distribution Upgrades, and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 Transmission Provider has completed the Interconnection Facilities Study pursuant to the Interconnection Facilities Study Agreement; and

5.5.2 Where applicable, Interconnection Customer has provided security to Transmission Owner in accordance with Article 11.6 by the dates specified in Appendix B, Milestones.

5.6 **Construction Commencement.** Transmission Owner shall commence construction of the Transmission Owner's Interconnection Facilities, Network Upgrades, Transmission Owner's System Protection Facilities, Distribution Upgrades, and Generator Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval; and

5.6.2 Where applicable, Interconnection Customer has provided security to Transmission Owner in accordance with Article 11.6 by the dates specified in Appendix B, Milestones.

5.7 **Work Progress**. Transmission Owner and Interconnection Customer will keep each other and Transmission Provider advised periodically as to the progress of their respective design, procurement and construction efforts. Either Transmission Owner or Interconnection Customer may, at any time, request a progress report from the other, with a copy to be provided to the other Parties. If, at any time, Interconnection Customer determines that the completion of the Transmission Owner's Interconnection Facilities, Network Upgrades, or Transmission Owner's System Protection Facilities will not be required until after the specified In-Service Date, Interconnection Customer will provide written notice to Transmission Provider and Transmission Owner of such later date upon which the completion of the Transmission Owner's Interconnection Facilities, Network Upgrades or Transmission Owner's System Protection Facilities will be required. Transmission Owner may delay the In-Service Date of its facilities accordingly.

5.8 **Information Exchange**. As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Interconnection Facilities and compatibility of the Interconnection Facilities with the Transmission System or Distribution System, as applicable, and shall work diligently and

in good faith to make any necessary design changes.

5.9 Other Interconnection Options.

5.9.1 Limited Operation. If any of the Transmission Owner's Interconnection Facilities, Network Upgrades, or Transmission Owner's System Protection Facilities, Distribution Upgrades or Generator Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Generating Facility, Transmission Provider shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Generating Facility and the Interconnection Customer's Interconnection Facilities may operate prior to the completion of the Transmission Owner's Interconnection Facilities, Network Upgrades, Transmission Owner's System Protection Facilities, Distribution Upgrades or Generator Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this GIA. Transmission Provider and Transmission Owner shall permit Interconnection Customer to operate the Generating Facility and the Interconnection Customer's Interconnection Facilities in accordance with the results of such studies; provided, however, such studies reveal that such operation may occur without detriment to the Transmission System as then configured and in accordance with the safety requirements of Transmission Owner and any Governmental Authority.

The maximum permissible output of the Generating Facility will be updated on a quarterly basis if the Network Upgrades necessary for the interconnection of the Generating Facility pursuant to this GIA are not in service within six (6) months following the Commercial Operation Date of the Generating Facility as specified in Appendix B of this GIA. These quarterly studies will be performed using the same methodology set forth in Section 11.5 of the GIP. These quarterly updates will end when all Network Upgrades necessary for the interconnection of the Generating Facility pursuant to this GIA are in service.

5.9.2 Provisional Interconnection Service.
Upon the request of Interconnection Customer, and prior to completion of requisite Interconnection Facilities, Network Upgrades, Distribution Upgrades, or System Protection Facilities Transmission Provider may execute a Provisional Generator Interconnection Agreement or Interconnection Customer may request the filing of an unexecuted Provisional Generator Interconnection Agreement with the Interconnection Customer for limited interconnection service at the discretion of Transmission Provider based upon an evaluation that will consider the results of available studies. Transmission Provider shall determine, through available studies or additional studies as necessary, whether stability, short circuit, thermal, and/or voltage issues would arise if Interconnection Customer interconnects without modifications to the Generating Facility or Transmission Provider's system. Transmission Provider shall determine whether any Interconnection Facilities, Network Upgrades, Distribution Upgrades, or System

Protection Facilities that are necessary to meet the requirements of NERC, or any applicable Regional Entity for the interconnection of a new, modified and/or expanded Generating Facility are in place prior to the commencement of interconnection service from the Generating Facility. Where available studies indicate that such Interconnection Facilities, Network Upgrades, Distribution Upgrades, and/or System Protection Facilities that are required for the interconnection of a new, modified and/or expanded Generating Facility are not currently in place, Transmission Provider will perform a study, at the Interconnection Customer's expense, to confirm the facilities that are required for Provisional Interconnection Service. The maximum permissible output of the Generating Facility in the Provisional Generator Interconnection Agreement shall be studied and updated on a quarterly basis. Interconnection Customer assumes all risk and liabilities with respect to changes between the Provisional Generator Interconnection Agreement and the Generator Interconnection Agreement, including changes in output limits and Interconnection Facilities, Network Upgrades, Distribution Upgrades, and/or System Protection Facilities cost responsibilities.

5.10 Interconnection Customer's Interconnection Facilities. Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A.

5.10.1 Interconnection Customer's Interconnection Facility Specifications. Interconnection Customer shall submit initial design and specifications for the ICIF, including Interconnection Customer's System Protection Facilities, to Transmission Provider and Transmission Owner at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final design and specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Transmission Provider at Transmission Provider's option, and Transmission Owner shall review such specifications to ensure that the ICIF are compatible with their respective technical specifications, operational control, and safety requirements and comment on such design and specifications within thirty (30) Calendar Days of Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 Transmission Provider's and Transmission Owner's Review. Transmission Provider's and Transmission Owner's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Provider and Transmission Owner, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control and safety requirements of Transmission Provider and Transmission Owner.

5.10.3 ICIF Construction. The ICIF shall be designed and constructed in accordance

with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Interconnection Customer shall deliver to Transmission Provider and Transmission Owner "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with the Interconnection Customer's step-up transformers, the facilities connecting the Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Generating Facility. Interconnection Customer shall provide Transmission Provider and Transmission Owner with Interconnection Customer's specifications for the excitation system, automatic voltage regulator, Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

5.11 Transmission Owner's Interconnection Facilities Construction. The Transmission Owner's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Transmission Owner shall deliver to Transmission Provider (if requested) and Interconnection Customer the "as-built" drawings, information and documents for the Transmission Owner's Interconnection Facilities specified in Appendix C to this GIA.

Such drawings, information and documents shall be deemed Confidential Information.

Upon completion, the Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades shall be under the control of Transmission Provider or its designated representative.

5.12 Access Rights. Upon reasonable notice by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish *at no cost* to the other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Generating Facility with the Transmission System; (ii) operate and maintain the Generating Facility, the Interconnection Facilities and the Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this GIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

5.13 Lands of Other Property Owners. If any part of the Transmission Owner's Interconnection Facilities, Network Upgrades, and/or Distribution Upgrades is to be installed on property owned by persons other than Interconnection Customer or Transmission Owner, Transmission Owner shall at Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority to the extent permitted and consistent with Applicable Laws and Regulations and, to the extent consistent with such Applicable Laws and Regulations, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove the Transmission Owner's Interconnection Facilities, Network Upgrades and/or Distribution Upgrades upon such property.

5.14 Permits. Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to the Transmission Owner's own, or an Affiliate's, generation to the extent that Transmission Owner or its Affiliate owns generation.

5.15 Early Construction of Base Case Facilities. (Includes facilities required for all queued projects with interconnection agreements).Interconnection Customer may request Transmission Owner to construct, and Transmission Owner shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades, Transmission Owner's System Protection Facilities or Distribution Upgrades required for Interconnection Customer to be interconnected to the Transmission or Distribution System, as applicable, which are included in the Base Case of the Interconnection Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer with a prior GIA, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date. Any such Network Upgrades, System Protection Facilities or Distribution Upgrades are included in the facilities to be constructed and as set forth in Appendix A to this GIA to the extent they are reasonably known.

5.16 Suspension.

5.16.1 Interconnection Customer's Right to Suspend for Force Majeure Event; Obligations. Provided that such suspension is permissible under the authorizations, permits or approvals granted for the construction of such Interconnection Facilities, Network Upgrades or Stand Alone Network Upgrades, Interconnection Customer will not suspend unless a Force Majeure event occurs.

Interconnection Customer must provide written notice of its request for

suspension to Transmission Provider and Transmission Owner, and provide a description of the Force Majeure event that is acceptable to Transmission Provider. Suspension will only apply to Interconnection Customer milestones and Interconnection Facilities described in the Appendices of this GIA. Prior to suspension, Interconnection Customer must also provide security acceptable to Transmission Owner, equivalent to the higher of $5 million or the total cost of all Network Upgrades, Transmission Owner's System Protection Facilities, and Distribution Upgrades listed in Appendix A of this GIA. Network Upgrades and Transmission Owner's Interconnection Facilities will be constructed on the schedule described in the Appendices of this GIA unless: (1) construction is prevented by the order of a Governmental Authority; (2) the Network Upgrades are not needed by any other project; or (3) Transmission Owner or Transmission Provider determines that a Force Majeure event prevents construction. In the event of (1), (2), or (3) security shall be released upon the determination that the Network Upgrades will no longer be constructed.

If suspension occurs, the Transmission or Distribution System, as applicable, shall be left in a safe and reliable condition in accordance with Good Utility Practice and the Transmission Provider's and Transmission Owner's safety and reliability criteria. In such event, Interconnection Customer shall be responsible for all reasonable and necessary costs which Transmission Provider and Transmission Owner (i) have incurred pursuant to this GIA prior to the suspension and (ii) incur in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Transmission or Distribution System, as applicable, during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Transmission Provider and Transmission Owner cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Transmission Provider and Transmission Owner shall obtain Interconnection Customer's authorization to do so.

Transmission Provider and Transmission Owner shall each invoice Interconnection Customer for such costs pursuant to Article 12 and shall use Reasonable Efforts to minimize its costs. In the event Interconnection Customer suspends work by Transmission Owner required under this GIA pursuant to this Article 5.16, and has not requested Transmission Owner to recommence the work required under this GIA on or before the expiration of three (3) years following commencement of such suspension, this GIA shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Transmission Provider, if no effective date is specified.

5.16.2 Effect of Missed Interconnection Customer Milestones. If Interconnection Customer fails to provide notice of suspension pursuant to Article 5.16, and Interconnection Customer fails to fulfill or complete any Interconnection Customer Milestone provided in Appendix B ("Milestone"), this constitutes a

Breach under this GIA. Depending upon the consequences of the Breach and effectiveness of the cure pursuant to Article 17, the Transmission Owners' Milestones may be revised, following consultation with Interconnection Customer, consistent with Reasonable Efforts, and in consideration of all relevant circumstances. Parties shall employ Reasonable Efforts to maintain their remaining respective Milestones.

5.16.3 Effect of Suspension; Parties Obligations. In the event that Interconnection Customer suspends work pursuant to this Article 5.16, no construction duration, timelines and schedules set forth in Appendix B shall be suspended during the period of suspension unless ordered by a Governmental Authority, with such order being the Force Majeure event causing the suspension. Should Interconnection Customer request that work be recommenced, Transmission Owner shall be obligated to proceed with Reasonable Efforts and in consideration of all relevant circumstances including regional outage schedules, construction availability and material procurement in performing the work as described in Appendix A and Appendix B. Transmission Owner will provide Interconnection Customer with a revised schedule for the design, procurement, construction, installation and testing of the Transmission Owner's Interconnection Facilities and Network Upgrades. Upon any suspension by Interconnection Customer pursuant to Article 5.16, Interconnection Customer shall be responsible for only those costs specified in this Article 5.16.

5.17 Taxes.

5.17.1 Interconnection Customer Payments Not Taxable. The Parties intend that all payments or property transfers made by Interconnection Customer to Transmission Owner for the installation of the Transmission Owner's Interconnection Facilities, Network Upgrades, Transmission Owner's System Protection Facilities, Distribution Upgrades and Generator Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws. To the extent that Transmission Owner is a limited liability company and not a corporation, and has elected to be taxed as a partnership, then the following shall apply: Transmission Owner represents, and the Parties acknowledge, that Transmission Owner is a limited liability company and is treated as a partnership for federal income tax purposes. Any payment made by Interconnection Customer to Transmission Owner for Network Upgrades is to be treated as an upfront payment in accordance with Rev Proc 2005-35. It is anticipated by the parties that any amounts paid by Interconnection Customer to Transmission Owner for Network Upgrades will be reimbursed to Interconnection Customer in accordance with the terms of this GIA, provided Interconnection Customer fulfills its obligations under this GIA.

5.17.2 **Representations and Covenants.** In accordance with IRS Notice 2016-36, Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Generating Facility will pass to another party prior to the transmission of the electricity on the Transmission System, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to Transmission Owner for the Transmission Owner's Interconnection Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of the Transmission Owner's Interconnection Facilities that is a "dual-use intertie," within the meaning of IRS Notice 2016-36, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 2016-36. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At Transmission Owner's request, Interconnection Customer shall provide Transmission Owner with a report from an independent engineer confirming its representation in clause (iii), above, with a copy to Transmission Provider. Transmission Owner represents and covenants that the cost of the Transmission Owner's Interconnection Facilities paid for by Interconnection Customer will have no net effect on the base upon which rates are determined.

5.17.3 **Indemnification for the Cost Consequences of Current Tax Liability** Upon Transmission Owner. Notwithstanding Article 5.17.1 and to the extent permitted by law, Interconnection Customer shall protect, indemnify and hold harmless Transmission Owner from the cost consequences of any tax liability imposed against Transmission Owner as the result of payments or property transfers made by Interconnection Customer to Transmission Owner under this GIA for Interconnection Facilities, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Transmission Owner.

Transmission Owner shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Interconnection Customer under this GIA unless (i) Transmission Owner has determined, in good faith, that the payments or property transfers made by Interconnection Customer to Transmission Owner should be reported as income subject to taxation or (ii) any Governmental Authority directs Transmission Owner to report payments or property as income subject to taxation; provided, however, that Transmission Owner may require Interconnection Customer to provide security for Interconnection Facilities, in a form reasonably acceptable to Transmission Owner (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences or any current tax liability under this Article 5.17.

Interconnection Customer shall reimburse Transmission Owner for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Transmission Owner of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten-year testing period and the applicable statute of limitation, as it may be extended by Transmission Owner upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

5.17.4 Tax Gross-Up Amount. Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the parties, this means that Interconnection Customer will pay Transmission Owner, in addition to the amount paid for the Interconnection Facilities, Network Upgrades, Transmission Owner's System Protection Facilities, and/or Distribution Upgrades, an amount equal to (1) the current taxes imposed on Transmission Owner ("Current Taxes") on the excess of (a) the gross income realized by Transmission Owner as a result of payments or property transfers made by Interconnection Customer to Transmission Owner under this GIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit Transmission Owner to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on Transmission Owner's composite federal and state tax rates at the time the payments or property transfers are received and Transmission Owner will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting Transmission Owner's anticipated tax depreciation deductions as a result of such payments or property transfers by Transmission Owner's current weighted average cost of capital. Thus, the formula for calculating Interconnection Customer's liability to Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.17.5 Private Letter Ruling or Change or Clarification of Law. At Interconnection Customer's request and expense, Transmission Owner shall file with the IRS a

request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Interconnection Customer to Transmission Owner under this GIA are subject to federal income taxation. Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Interconnection Customer's knowledge. Transmission Owner and Interconnection Customer shall cooperate in good faith with respect to the submission of such request.

Transmission Owner shall keep Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. Transmission Owner shall allow Interconnection Customer to attend all meetings with IRS officials about the request and shall permit Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 Subsequent Taxable Events. If, within 10 years from the date on which the relevant Transmission Owner's Interconnection Facilities are placed in service, (i) Interconnection Customer breaches the covenant contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this GIA terminates and Transmission Owner retains ownership of the Interconnection Facilities, Network Upgrades, Transmission Owner's System Protection Facilities, and/or Distribution Upgrades, Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Transmission Owner, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 Contests. In the event any Governmental Authority determines that Transmission Owner's receipt of payments or property constitutes income that is subject to taxation, Transmission Owner shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Transmission Owner may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Transmission Owner shall file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Transmission Owner reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Transmission Owner shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall reasonably permit Interconnection Customer or an Interconnection Customer representative to

attend contest proceedings.

Interconnection Customer shall pay to Transmission Owner on a periodic basis, as invoiced by Transmission Owner, Transmission Owner's documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Transmission Owner may agree to a settlement either with Interconnection Customer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Transmission Owner, but reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally-recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. Any settlement without Interconnection Customer's consent or such written advice will relieve Interconnection Customer from any obligation to indemnify Transmission Owner for the tax at issue in the contest.

5.17.8 **Refund.** In the event that (a) a private letter ruling is issued to Transmission Owner which holds that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Owner under the terms of this GIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Transmission Owner in good faith that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Owner under the terms of this GIA is not taxable to Transmission Owner, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Interconnection Customer to Transmission Owner are not subject to federal income tax, or (d) if Transmission Owner receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Interconnection Customer to Transmission Owner pursuant to this GIA, Transmission Owner shall promptly refund to Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amounts paid by Interconnection Customer to Transmission Owner for such taxes which Transmission Owner did not submit to the taxing authority, calculated in accordance with the methodology set forth in 18 C.F.R. Section 35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Transmission

Owner refunds such payment to Interconnection Customer, and

(iii) with respect to any such taxes paid by Transmission Owner, any refund or credit Transmission Owner receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to Transmission Owner for such overpayment of taxes (including any reduction in interest otherwise payable by Transmission Owner to any Governmental Authority resulting from an offset or credit); provided, however, that Transmission Owner will remit such amount promptly to Interconnection Customer only after and to the extent that Transmission Owner has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to the Transmission Owner's Interconnection Facilities.

The intent of this provision is to leave both parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

5.17.9 Taxes Other Than Income Taxes. Upon the timely request by Interconnection Customer, and at Interconnection Customer's sole expense, Transmission Owner shall appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Transmission Owner for which Interconnection Customer may be required to reimburse Transmission Owner under the terms of this GIA. Interconnection Customer shall pay to Transmission Owner on a periodic basis, as invoiced by Transmission Owner, Transmission Owner's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and Transmission Owner shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to Transmission Owner for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Transmission Owner.

5.18 Tax Status. Each Party shall cooperate with the other Parties to maintain each Party's tax status. Nothing in this GIA is intended to adversely affect any Party's tax-exempt status with respect to the issuance of bonds including, but not limited to, Local Furnishing Bonds.

5.19 Modification.

5.19.1 General. Either Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect another Party's facilities, that Party shall provide to the other Parties sufficient information regarding such modification so that the other Parties may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be Confidential Information hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Parties at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Generating Facility modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission Provider shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the Transmission or Distribution System as applicable, Transmission Owner's Interconnection Facilities, Network Upgrades, Transmission Owner's System Protection Facilities, and/or Distribution Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof which shall be the responsibility of Interconnection Customer.

5.19.2 Standards. Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this GIA and Good Utility Practice.

5.19.3 Modification Costs. Interconnection Customer shall not be directly assigned the costs of any additions, modifications, or replacements that Transmission Owner makes to the Transmission Owner's Interconnection Facilities, Network Upgrades, Transmission Owner's System Protection Facilities, Distribution Upgrades, or the Transmission or Distribution System, as applicable, to facilitate the interconnection of a third party to the Transmission Owner's Interconnection Facilities or the Transmission or Distribution System, as applicable, or to provide transmission service to a third party under the Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to the Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

ARTICLE 6. TESTING AND INSPECTION

6.1 Pre-Commercial Operation Date Testing and Modifications. Prior to the Commercial Operation Date, Transmission Owner shall test the Transmission Owner's

Interconnection Facilities, Network Upgrades, Transmission Owner's System Protection Facilities and Distribution Upgrades, and Interconnection Customer shall test each electric production device at the Generating Facility, Interconnection Customer's System Protection Facilities, including control equipment to limit injection at the POI to the level of Interconnection Service set forth in Appendix A and the Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Transmission Owner and Interconnection Customer shall make any modifications to their respective facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Generating Facility only if it has arranged for the delivery of such test energy.

6.2 **Post-Commercial Operation Date Testing and Modifications**. Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Generating Facility with the Transmission or Distribution System, as applicable, in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the Interconnection Facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

6.3 **Right to Observe Testing.** Each Party shall notify the other Parties in advance of its performance of tests of its Interconnection Facilities. The other Parties shall each have the right, at its own expense, to observe such testing.

6.4 **Right to Inspect**. Each Party shall have the right, but shall have no obligation to: (i) observe Transmission Owner's and Interconnection Customer's tests and/or inspection of any of their respective System Protection Facilities and other protective equipment, including power system stabilizers and control equipment; (ii) review the settings of the System Protection Facilities and other protective equipment; and (iii) review the maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. A Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Parties. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that a Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this GIA.

ARTICLE 7. METERING

7.1 **General.** Each Party shall comply with the Applicable Reliability Council requirements. Unless otherwise agreed by the Parties, Transmission Owner, at its election, or otherwise Interconnection Customer, shall install Metering Equipment (the "Metering Party") at the Point of Interconnection prior to any operation of the Generating Facility and

Transmission Owner, at its election, or otherwise Interconnection Customer shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Generating Facility shall be measured at or, at the Metering Party's option, compensated to, the Point of Interconnection. In addition to the Metering Equipment installed at the Point of Interconnection, if Interconnection Customer will share Interconnection Facilities with any other projects, Interconnection Customer shall install Metering Equipment either on its own Generating Facility or its own non-shared facilities sufficient to measure the output of such Interconnection Customer's Generating Facility separately from any other Generating Facilities with which it will share Interconnection Facilities. The Metering Party shall provide metering quantities, in analog and/or digital form, to the other Parties upon request. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

7.2 **Check Meters.** Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check the Metering Equipment owned by the Metering Party. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this GIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Provider, Transmission Owner or their designees. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

7.3 **Standards**. The Metering Party shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards.

7.4 **Testing of Metering Equipment**. The Metering Party shall inspect and test Metering Equipment upon installation and at least once every two (2) years thereafter. If requested to do so by a Party, the Metering Party shall, at the requesting Party's expense, inspect or test Metering Equipment more frequently than every two (2) years. The Metering Party shall give reasonable notice to the other Parties of the time when any inspection or test shall take place, and the other Parties may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to the Metering Party's failure to maintain, then the Metering Party shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent (2%) from the measurement made by the standard meter used in the test, the Metering Party shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the previous test of the Metering Equipment.

7.5 **Metering Data**. At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Provider and Transmission Owner and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Generating Facility to the Point of Interconnection.

ARTICLE 8. COMMUNICATIONS

8.1 **Interconnection Customer Obligations**. Interconnection Customer shall maintain satisfactory operating communications with Transmission Provider's Transmission System dispatcher or representative designated by Transmission Provider. Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Provider as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Generating Facility to the location(s) specified by Transmission Provider. Any required maintenance of such communications equipment shall be performed by and at the cost of Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

Unless the Generating Facility is an Intermittent Resource not relying on wind or solar as a fuel source, Interconnection Customer shall install communication and control equipment such that the Generating Facility can receive and respond to the appropriate dispatch signals while operating under the Tariff. Where applicable, the requirements of the communication and control equipment will be enumerated in Appendix C to this GIA.

8.2 **Remote Terminal Unit (RTU)**. Prior to the Initial Synchronization Date of the Generating Facility, a remote terminal unit, or equivalent data collection and transfer equipment acceptable to both Parties, shall be installed by Interconnection Customer, or by Transmission Owner at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Owner and Transmission Provider through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Owner and Transmission Provider. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Provider and Transmission Owner.

Each Party will promptly advise the other Parties if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 **No Annexation.** Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

8.4 **Provision of Data from a Variable Energy Resource.** The Interconnection Customer whose Generating Facility is a Variable Energy Resource shall provide meteorological and forced outage data to the Transmission Provider to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The Interconnection Customer with a Variable Energy Resource having wind as the energy source will, upon request by the Transmission Provider, be required to provide the Transmission Provider with site-specific meteorological data including: temperature, wind speed, wind direction, and atmospheric pressure. The Interconnection Customer with a Variable Energy Resource having solar as the energy source will, upon request by the Transmission Provider, be required to provide the Transmission Provider with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The Transmission Provider and Interconnection Customer whose Generating Facility is a Variable Energy Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power production forecast. The Interconnection Customer whose Generating Facility is a Variable Energy Resource also shall submit data to the Transmission Provider regarding all forced outages to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The exact specifications of the meteorological and forced outage data to be provided by the Interconnection Customer to the Transmission Provider, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Variable Energy Resource, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological and forced outage data must be commensurate with the power production forecasting employed by the Transmission Provider. Data requirements for meteorological and forced outage data will be negotiated by the Transmission Provider and the Interconnection Customer, and will be set forth in Appendix C, Interconnection Details, of this GIA.

ARTICLE 9. OPERATIONS

9.1 **General.** Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to any Party all information that may reasonably be required by that Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 **Local Balancing Authority Notification**. At least three (3) months before Initial Synchronization Date, Interconnection Customer shall notify Transmission Provider and Transmission Owner in writing of the Local Balancing Authority in which the Generating

Facility will be located. If Interconnection Customer elects to locate the Generating Facility through dynamic metering/scheduling in a Local Balancing Authority other than the Local Balancing Authority in which the Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this GIA, and remote Local Balancing Authority generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Generating Facility in the other Local Balancing Authority.

9.3 Transmission Provider and Transmission Owner Obligations. Transmission Provider shall cause the Transmission System and the Transmission Owner's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner in accordance with this GIA. Transmission Provider, or its designee, may provide operating instructions to Interconnection Customer consistent with this GIA and the Tariff and, if applicable, Transmission Owner's operating protocols and procedures as they may change from time to time. Transmission Provider will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

9.4 Interconnection Customer Obligations. Interconnection Customer shall at its own expense operate, maintain and control the Generating Facility and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this GIA. The Generating Facility must be operated in accordance with the operating limits, if any, in the Interconnection Facilities Study and specified in Appendix C of this GIA. Interconnection Customer shall operate the Generating Facility and the Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of Transmission Provider or its designated Local Balancing Authority Operator of which the Generating Facility is part, as such requirements are set forth in Appendix C, Interconnection Details, of this GIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. Any Party may request that a Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this GIA.

9.5 Start-Up and Synchronization. Consistent with the Parties' mutually acceptable procedures, Interconnection Customer is responsible for the proper synchronization of the Generating Facility to the Transmission or Distribution System, as applicable.

9.6 Reactive Power and Primary Frequency Response.

9.6.1 Power Factor Design Criteria.

9.6.1.1 Synchronous Generation. Interconnection Customer shall design the Generating Facility to be capable of maintaining a composite power delivery at continuous rated power output at the Point of Interconnection at all power factors over 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all synchronous generators in the Local Balancing Authority on a

comparable basis. The applicable Local Balancing Authority power factor requirements are listed on the Transmission Provider's website at

https://cdn.misoenergy.org/Reactive_Generator_Requirements108137.pdf

and may be referenced in the Appendices to this GIA. The Generating Facility shall be capable of continuous dynamic operation throughout the power factor design range as measured at the Point of Interconnection. Such operation shall account for the net effect of all energy production devices on the Interconnection Customer's side of the Point of Interconnection.

9.6.1.2 Non-Synchronous Generation. Interconnection Customer shall design the Generating Facility to be capable of maintaining a composite power delivery at continuous rated power output at the high-side of the generator substation at all power factors over 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all non-synchronous generators in the Local Balancing Authority on a comparable basis. The applicable Local Balancing Authority power factor requirements are listed on the Transmission Provider's website at

https://cdn.misoenergy.org/Reactive_Generator_Requirements108137.pdf

and may be referenced in the Appendices to this GIA. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that have not yet completed a System Impact Study as of the effective date of the Final Rule establishing this requirement (Order No. 827). These requirements apply to existing non-synchronous generators making upgrades that require a new Generator Interconnection Agreement only where the Transmission Provider's System Impact Study shows the need for reactive power as a result of an upgrade. If applicable, these requirements will be memorialized in Appendix C to this GIA.

9.6.2 Voltage Schedules. Once Interconnection Customer has synchronized the Generating Facility with the Transmission System, Transmission Provider shall require Interconnection Customer to operate the Generating Facility to produce or absorb reactive power within the design limitations of the Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria), to maintain the output voltage or power factor at the Point of Interconnection as specified by Transmission Provider. Transmission Provider's voltage schedules shall treat all sources of reactive power in the Local Balancing Authority in an equitable and not unduly discriminatory manner. Transmission Provider shall exercise

Reasonable Efforts to provide Interconnection Customer with such schedules at least one (1) Calendar Day in advance, and may make changes to such schedules as necessary to maintain the reliability of the Transmission or Distribution System as applicable. Interconnection Customer shall operate the Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify Transmission Provider's system operator, or its designated representative.

9.6.2.1 Voltage Regulators. Whenever the Generating Facility is operated in parallel with the Transmission or Distribution System as applicable and voltage regulators are capable of operation, Interconnection Customer shall operate the Generating Facility with its speed governors and voltage regulators in automatic operation. If the Generating Facility's voltage regulators are not capable of such automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative, and ensure that such Generating Facility's reactive power production or absorption (measured in MVARs) are within the design capability of the Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Generating Facility to disconnect automatically or instantaneously from the Transmission or Distribution System, as applicable, or trip any generating unit comprising the Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Local Balancing Authority on a comparable basis.

9.6.3 Payment for Reactive Power. Payments for reactive power shall be pursuant to any tariff or rate schedule filed by Transmission Provider and approved by the FERC.

9.6.4 Primary Frequency Response. This Section 9.6.4 shall only apply in the event that the Interconnection Request for the Generating Facility completed Definitive Planning Phase Interconnection Customer Decision Point 2 after May 15, 2018.

Interconnection Customer shall ensure the primary frequency response capability of its Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term "functioning governor or equivalent controls" as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Generating Facility's real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of

operating: (1) with a maximum 5 percent droop and ±0.036 Hz deadband; or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved NERC Reliability Standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate capacity of the Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based on an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Generating Facility's real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Generating Facility's real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Generating Facility with the Transmission System, Interconnection Customer shall operate the Generating Facility consistent with the provisions specified in Sections 9.6.4.1 and 9.6.4.2 of this GIA. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Generating Facilities.

9.6.4.1 Governor or Equivalent Controls. Whenever the Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) in coordination with Transmission Provider and/or the relevant balancing authority, set the deadband parameter to: (a) a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (b) implement the relevant droop and deadband settings from an approved NERC Reliability Standard that provides for equivalent or more stringent parameters. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant balancing authority upon request. If Interconnection Customer needs to operate the Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider and the relevant balancing authority, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable

estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Generating Facility's governor or equivalent controls to a minimum whenever the Generating Facility is operated in parallel with the Transmission System.

9.6.4.2 Timely and Sustained Response. Interconnection Customer shall ensure that the Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

9.6.4.3 Exemptions. Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 9.6.4, 9.6.4.1, and 9.6.4.2 of this GIA. Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Section 9.6.4, but shall be otherwise exempt from the operating requirements in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.4 of this GIA.

9.6.4.4 Electric Storage Resources. Interconnection Customer interconnecting an electric storage resource shall establish an operating range in Appendix C that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in Sections 9.6.4, 9.6.4.1, 9.6.4.2 and 9.6.4.3 of this GIA. Appendix C shall specify whether the operating range is static or dynamic, and shall consider (1) the expected magnitude of frequency deviations in the

interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Interconnection Customer, and in consultation with the relevant transmission owner or balancing authority as appropriate. If the operating range is dynamic, then Appendix C must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer's electric storage resource is required to provide timely and sustained primary frequency response consistent with Section 9.6.4.2 of this GIA when it is online and dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Interconnection Customer's electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer's electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

9.7 Outages and Interruptions.

9.7.1 Outages.

9.7.1.1 Outage Authority and Coordination. Interconnection Customer and Transmission Owner may each in accordance with Good Utility Practice in coordination with the other Party and Transmission Provider remove from service any of its respective Interconnection Facilities, System Protection Facilities, Network Upgrades, System Protection Facilities or Distribution Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to notify one another and schedule such removal on a date and time mutually acceptable to the Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Parties of such removal.

9.7.1.2 Outage Schedules. Transmission Provider shall post scheduled outages of transmission facilities on the OASIS. Interconnection Customer shall submit its planned maintenance schedules for the Generating Facility to Transmission Provider and Transmission Owner for a minimum of a rolling twenty-four (24) month period in accordance with the Transmission Provider's procedures. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Transmission System; provided, however, adequacy of generation supply shall not be a criterion in determining Transmission System reliability.

Transmission Provider shall compensate, pursuant to applicable Transmission Provider tariff or rate schedule, Interconnection Customer for any additional direct costs that Interconnection Customer incurs as a result of having to reschedule maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost Interconnection Customer would have incurred absent the Transmission Provider's request to reschedule maintenance. Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, Interconnection Customer had modified its schedule of maintenance activities.

Costs shall be determined by negotiation between Transmission Provider and Interconnection Customer prior to implementation of the voluntary change in outage schedules, or if such request is made by or on behalf of a Transmission Customer requesting firm service, costs and recovery of costs shall be determined through a bilateral agreement between the Transmission Customer and Interconnection Customer. Voluntary changes to outage schedules under this Article 9.7.1.2 are separate from actions and compensation required under Article 13 and for which costs are recovered in accordance with Transmission Provider's applicable tariff or rate schedule.

9.7.1.3 Outage Restoration. If an outage on either the Interconnection Customer's or Transmission Owner's Interconnection Facilities, Network Upgrades, System Protection Facilities or Distribution Upgrades adversely affects a Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Parties, to the extent such information is known, information on the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable

with written notice to the other Parties explaining the nature of the outage.

9.7.2 Interruption of Service. If required by Good Utility Practice to do so, Transmission Provider may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

9.7.2.1 The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

9.7.2.2 Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission or Distribution System, as applicable;

9.7.2.3 When the interruption or reduction must be made under circumstances which do not allow for advance notice, Transmission Provider shall notify Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

9.7.2.4 Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, Transmission Provider shall notify Interconnection Customer in advance regarding the timing of such scheduling and further notify Interconnection Customer of the expected duration. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to Interconnection Customer, Transmission Owner and Transmission Provider;

9.7.2.5 The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Generating Facility, Interconnection Facilities, and the Transmission or Distribution System, as applicable to their normal operating state, consistent with system conditions and Good Utility Practice.

9.7.3 Under-Frequency, Over-Frequency, Under-Voltage, and Over-Voltage Conditions. The Transmission System is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency or under-voltage system disturbance. Interconnection Customer shall implement under-frequency, over-frequency, under-voltage, and over-voltage relay set points for the Generating Facility as required by the

Applicable Reliability Council to ensure "ride through" capability of the Transmission System. Generating Facility response to frequency and/or voltage deviations of pre-determined magnitudes, including under-frequency, over-frequency, under-voltage, and over-voltage, shall be studied and coordinated with Transmission Provider in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the Transmission System during system disturbances within a range of under-frequency, over-frequency, under-voltage, and over-voltage conditions, in accordance with Good Utility Practice.

9.7.4 System Protection and Other Control Requirements.

9.7.4.1 System Protection Facilities. Interconnection Customer shall, at its expense, install, operate and maintain its System Protection Facilities as a part of the Generating Facility or the Interconnection Customer's Interconnection Facilities. Transmission Owner shall install at Interconnection Customer's expense any Transmission Owner's System Protection Facilities that may be required on the Transmission Owner's Interconnection Facilities or the Transmission Owner's transmission or distribution facilities as a result of the interconnection of the Generating Facility and the Interconnection Customer's Interconnection Facilities.

9.7.4.2 Interconnection Customer's and Transmission Owner's System Protection Facilities shall be designed and coordinated with Affected Systems in accordance with Good Utility Practice.

9.7.4.3 Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

9.7.4.4 Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of the Generating Facility.

9.7.4.5 Each Party will test, operate and maintain their respective System Protection Facilities in accordance with Good Utility Practice.

9.7.4.6 Prior to the In-Service Date, and again prior to the Commercial Operation Date, Interconnection Customer or Transmission Owner, or their respective agents, shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, Interconnection Customer or Transmission Owner shall each perform both calibration and functional trip tests of their

respective System Protection Facilities. These tests do not require the tripping of any in-service generating unit. These tests do, however, require that all protective relays and lockout contacts be activated.

9.7.5 Requirements for Protection. In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Generating Facility to any short circuit occurring on the Transmission or Distribution System, as applicable, not otherwise isolated by Transmission Owner's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Transmission or Distribution System, as applicable. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Generating Facility and the Transmission or Distribution System, as applicable, at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Generating Facility and Interconnection Customer's other equipment if conditions on the Transmission or Distribution System, as applicable, could adversely affect the Generating Facility.

9.7.6 Power Quality. Neither Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, and any applicable superseding electric industry standard, the applicable superseding electric industry standard shall control.

9.8 Switching and Tagging Rules. Prior to the Initial Synchronization Date, each Party shall provide the other Parties a copy of its switching and tagging rules that are applicable to the other Parties' activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

9.9 Use of Interconnection Facilities by Other Parties.

9.9.1 Purpose of Interconnection Facilities. Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Generating Facility to the Transmission or Distribution System, as applicable, and shall be used for no other purpose.

9.9.2 Other Users. If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld or delayed, to allow one or more Parties to use the Transmission Owner's Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Owner, all non-Party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any non-Party users based upon the pro rata use of the Interconnection Facilities by Transmission Owner, all non-Party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to Dispute Resolution pursuant to Section 12 of the Tariff.

9.10 **Disturbance Analysis Data Exchange.** The Parties will cooperate with one another in the analysis of disturbances to either the Generating Facility or the Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

ARTICLE 10. MAINTENANCE

10.1 **Transmission Owner Obligations.** Transmission Owner shall maintain the Transmission Owner's Interconnection Facilities in a safe and reliable manner and in accordance with this GIA and all Applicable Laws and Regulations.

10.2 **Interconnection Customer Obligations**. Interconnection Customer shall maintain the Generating Facility and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this GIA and all Applicable Laws and Regulations.

10.3 **Coordination.** The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Generating Facility and the Interconnection Facilities.

10.4 **Secondary Systems**. Each Party shall cooperate with the other in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a

Party's facilities and equipment which may reasonably be expected to impact another Party. Each Party shall provide advance notice to the other Parties before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

10.5 Operating and Maintenance Expenses. Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing Interconnection Service or Transmission Service to a non-Party and such non-Party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Transmission Owner's Interconnection Facilities to the extent required by Transmission Owner on a comparable basis.

ARTICLE 11. PERFORMANCE OBLIGATION

11.1 Interconnection Customer's Interconnection Facilities. Interconnection Customer shall design, procure, construct, install, own and/or control the Interconnection Customer's Interconnection Facilities described in Appendix A at its sole expense.

11.2 Transmission Owner's Interconnection Facilities. Transmission Owner shall design, procure, construct, install, own and/or control the Transmission Owner's Interconnection Facilities described in Appendix A at the sole expense of Interconnection Customer.

11.3 Network Upgrades, System Protection Facilities and Distribution Upgrades. Transmission Owner shall design, procure, construct, install, and own the Network Upgrades, Transmission Owner's System Protection Facilities and Distribution Upgrades described in Appendix A. Interconnection Customer shall be responsible for all costs related to Distribution Upgrades and/or Generator Upgrades. As required by Section 7.3.2.1 and 7.3.3.1 of Attachment X, Transmission Owner shall have provided Transmission Provider with written notice if Transmission Owner elects to fund the capital for the Network Upgrades and Transmission Owner's System Protection Facilities; otherwise, such facilities, if any, shall be solely funded by Interconnection Customer. In the event that the Transmission Owner elects to fund the capital costs of the Network Upgrades and/or Transmission Owner's System Protection Facilities, then the Parties shall enter into a Facilities Service Agreement. The Facilities Service Agreement shall take the form of the *pro forma* Facilities Service Agreement that is included as Appendix 14 of Attachment X to the MISO Tariff.

11.3.1 Contingencies Affecting Network Upgrades, System Protection Facilities and Distribution Upgrades**.** Network Upgrades, System Protection Facilities and Distribution Upgrades that are required to accommodate the Generating Facility may be modified because (1) a higher queued interconnection request withdrew or was deemed to have withdrawn, (2) the interconnection agreement associated with a higher queued interconnection request was terminated prior to the project's

In-Service Date, (3) the Commercial Operation Date for a higher queued interconnection request is delayed, or the project itself is delayed (including due to suspension) such that facilities required to accommodate lower queued projects or the project itself may be altered, (4) the queue position is reinstated for a higher-queued interconnection request whose queue position was subject to dispute resolution, (5) changes occur in Transmission Provider or Transmission Owner equipment design standards or reliability criteria giving rise to the need for restudy, (6) the facilities required to accommodate a higher queued Interconnection Request were modified constituting a Material Modification pursuant to Section 4.4 of the GIP, (7) a GIA with an effective date prior to this GIA is terminated, or (8) when ordered to restudy by FERC. The higher queued Interconnection Requests that could impact the Network Upgrades, System Protection Facilities and Distribution Upgrades required to accommodate the Generating Facility, and possible Modifications that may result from the above listed events affecting the higher queued Interconnection Requests, to the extent such modifications are reasonably known and can be determined, and estimates of the costs associated with such required Network Upgrades, System Protection Facilities and Distribution Upgrades, are provided in Appendix A.

11.3.2 Agreement to Restudy and Cost Reallocation**.** In the event that one of the contingencies listed in Article 11.3.1 occurs, at any time before the Network Upgrades, Common Use Upgrades, Shared Network Upgrades, System Protection Facilities and/or Distribution Upgrades associated with higher queued Interconnection Requests with GIA in effect prior to this GIA are completed, Transmission Provider may determine, in its discretion, that a restudy is required. If a restudy is required, Transmission Provider will provide notice to Interconnection Customer and Interconnection Customer agrees to enter into an Interconnection Study Agreement for such restudy. Transmission Provider will reevaluate the need for any Common Use Upgrade(s) and/or Shared Network Upgrade(s), and if still required, reallocate the cost and responsibility for any Common Use Upgrade and/or Shared Network Upgrade, without a restudy when possible, or with a restudy if the Transmission Provider deems it necessary in order to ensure reliability of the Transmission System. The Parties agree to amend Appendix A to this GIA in accordance with Article 30.10 to reflect the results of any cost reallocation required under this Article 11.3.2.

11.3.3 Agreement to Fund Shared Network Upgrades. Interconnection Customer agrees to fund Shared Network Upgrades, as determined by Transmission Provider. Where applicable, payments to fund Shared Network Upgrade(s) that are made to Transmission Provider by Interconnection Customer will be disbursed by Transmission Provider to the appropriate entities that funded the Shared Network Upgrades in accordance with Attachment X and Attachment FF of the Tariff. In the event that Interconnection Customer fails to meet its obligation to fund Shared Network Upgrades, Transmission Owner and Transmission Provider shall not be responsible for the Interconnection Customer's funding obligation.

11.4 Transmission Credits.

11.4.1 Repayment of Amounts Advanced for Network Upgrades. Interconnection Customer shall be entitled to a cash repayment by Transmission Owner(s) and the Affected System Owner(s) that own the Network Upgrades, of the amount paid respectively to Transmission Owner and Affected System Operator, if any, for the Network Upgrades, as provided under Attachment FF of this Tariff and including any tax gross-up or other tax-related payments associated with the repayable portion of the Network Upgrades, and not repaid to Interconnection Customer pursuant to Article 5.17.8 or otherwise, to be paid to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under the Tariff and Affected System's Tariff for Transmission Services with respect to the Generating Facility. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC's regulations at 18 C.F.R. § 35.19 (a)(2)(iii) from the date of any payment for Network Upgrades through the date on which Interconnection Customer receives a repayment of such payment pursuant to this subparagraph. Interest shall not accrue during periods in which Interconnection Customer has suspended construction pursuant to Article 11 or the Network Upgrades have been determined not to be needed pursuant to this Article 11.4.1. Interconnection Customer may assign such repayment rights to any person.

If the Generating Facility is designated a Network Resource under the Tariff, or if there are otherwise no incremental payments for Transmission Service resulting from the use of the Generating Facility by Transmission Customer, and in the absence of another mutually agreeable payment schedule any repayments provided under Attachment FF shall be established equal to the applicable rate for Firm Point-To-Point Transmission Service for the pricing zone where the Network Load is located multiplied by the portion of the demonstrated output of the Generating Facility designated as a Network Resource by the Network Customer(s) or in the absence of such designation, equal to the monthly firm single system-wide rate defined under Schedule 7 of the Tariff multiplied by the portion of the demonstrated output of the Generating Facility under contract to Network Customer(s) and consistent with studies pursuant to Section 3.2.2.2 of the GIP.

Notwithstanding the foregoing, as applicable and consistent with the provisions of Attachment FF of this Tariff, Interconnection Customer, Transmission Provider, Transmission Owner, and Affected System Operator may adopt any alternative payment schedule that is mutually agreeable so long as Transmission Owner and Affected System Operator take one of the following actions no later than five (5) years from the Commercial Operation Date: (1) return to Interconnection Customer any amounts advanced for Network Upgrades not previously repaid, or (2) declare in writing that Transmission Owner or Affected System Operator will continue to provide payments to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an

alternative schedule that is mutually agreeable and provides for the return of all amounts advanced for Network Upgrades not previously repaid; however, full reimbursement shall not extend beyond twenty (20) years from the Commercial Operation Date.

If the Generating Facility is installed in phases, the amount eligible for refund as each phase achieves Commercial Operation will be reduced by the proportional amount of generation capacity not yet installed. However, all facilities in Appendix A other than the Generating Facility shall be built without consideration for the phasing of the Generating Facility as though the entire Generating Facility will be placed in Commercial Operation for the full output or increased output of the Generating Facility constructed by Interconnection Customer under this GIA.

If the Generating Facility fails to achieve Commercial Operation, but it or another generating facility is later constructed and makes use of the Network Upgrades, Transmission Owner and Affected System Operator shall at that time reimburse Interconnection Customer for the remaining applicable amounts that may be refundable pursuant to Attachment FF of this Tariff that were advanced for the Network Upgrades on their respective systems as described above. Before any such reimbursement can occur, Interconnection Customer, or the entity that ultimately constructs the Generating Facility, if different, is responsible for identifying the entity to which the reimbursement must be made.

11.4.2 Special Provisions for Transmission Provider as an Affected System to be covered under Separate Agreements. When the Transmission Owner's Transmission or Distribution System (including for this Article 11.4.2 independent distribution systems connected to the Transmission System) is an Affected System for an interconnection in another electric system, Transmission Provider will coordinate the performance of Interconnection Studies with the other system. Transmission Provider will determine if any Network Upgrades or Distribution Upgrades, which may be required on the Transmission System as a result of the interconnection, would not have been needed but for the interconnection. Unless Transmission Owner provides, under the interconnection agreement between Interconnection Customer and the other system, for the repayment of amounts advanced to Transmission Provider or an impacted Transmission Owner for Network Upgrades, Interconnection Customer, Transmission Provider, and the impacted Transmission Owner(s) shall enter into an agreement that provides for such repayment by Transmission Owner(s) as directed by Transmission Provider. The agreement shall specify the terms governing payments to be made by Interconnection Customer to the Affected System Operator as well as the payment of refunds by the Affected System Operator.

11.4.3 Notwithstanding any other provision of this GIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to

firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that Interconnection Customer, shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursement or transmission credits for transmission service that is not associated with the Generating Facility.

11.5 Initial Payment. Interconnection Customer shall elect (and provide its election to the Transmission Provider within five days of the commencement of negotiation of the GIA pursuant to Section 11.2 of the GIP) to make either 1) an initial payment equal to twenty (20) percent of the total cost of Network Upgrades, Transmission Owner Interconnection Facilities, Transmission Owner's System Protection Facilities, Distribution Upgrades and/or Generator Upgrades (if the In-Service Date is less than or equal to five (5) years of the initial payment date); or 2) an initial payment equal to ten (10) percent of the total cost of Network Upgrades, Transmission Owner Interconnection Facilities, Transmission Owner's System Protection Facilities, Distribution Upgrades and/or Generator Upgrades (if the In-Service Date exceeds the initial payment date by more than five (5) years); or 3) the total cost of Network Upgrades, Transmission Owner Interconnection Facilities, Transmission Owner's System Protection Facilities, Distribution Upgrades and/or Generator Upgrades in the form of security pursuant to Article 11.6. The initial payment shall be provided to Transmission Owner by Interconnection Customer pursuant to this Article 11.5 within the later of a) forty-five (45) Calendar Days of the execution of the GIA by all Parties, or b) forty-five (45) Calendar Days of acceptance by FERC if the GIA is filed unexecuted and the payment is being protested by Interconnection Customer, or c) forty-five (45) Calendar Days of the filing if the GIA is filed unexecuted and the initial payment is not being protested by Interconnection Customer. If the Interconnection Customer made its milestone payments in the form of cash and the Interconnection Customer elects a cash initial payment, then the Transmission Provider shall transfer those funds to the Transmission Owner on the Interconnection Customer's behalf.

11.6 Provision of Security. Unless otherwise provided in Appendix B, at least forty-five (45) Calendar Days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of an element, not otherwise funded under Article 11.5, of the Transmission Owner's Interconnection Facilities, Transmission Owner's System Protection Facilities, Network Upgrades, Distribution Upgrades or Stand-Alone Network Upgrades, or at the request of Transmission Owner if regulatory approvals are required for the construction of such facilities, Interconnection Customer shall provide Transmission Owner, at Interconnection Customer's selection, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Owner and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1. Such security for payment shall be in an amount sufficient to cover the applicable costs and cost commitments, in addition to those funded under Article 11.5, required of the Party responsible for building the facilities pursuant to the construction schedule developed in Appendix B for designing, engineering, seeking regulatory approval from any Governmental Authority, constructing, procuring and installing the applicable portion of the Transmission Owner's Interconnection Facilities, Transmission

Owner's System Protection Facilities, Network Upgrades, Distribution Upgrades or Stand-Alone Network Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to Transmission Owner for these purposes.

In addition:

11.6.1 The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Owner, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

11.6.2 The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Owner and must specify a reasonable expiration date.

11.6.3 The surety bond must be issued by an insurer reasonably acceptable to Transmission Owner and must specify a reasonable expiration date.

11.6.4 If the Shared Network Upgrade is not in service, Interconnection Customer will not be required to make a payment under Schedule 26-B until the Shared Network Upgrade is in service, but Interconnection Customer will provide, as applicable, an Irrevocable Letter of Credit to fund any Shared Network Upgrade pursuant to Attachment FF of the Tariff. The Irrevocable Letter of Credit shall be in an amount sufficient to cover the Interconnection Customer's share of the applicable costs and cost commitments associated with the Shared Network Upgrades. Transmission Provider may periodically adjust the Interconnection Customer's share of the applicable costs and cost commitment of Shared Network Upgrades and may require Interconnection Customer to adjust the amount of the Irrevocable Letter of Credit accordingly.

11.7 **Interconnection Customer Compensation.** If Transmission Provider requests or directs Interconnection Customer to provide a service pursuant to Article 13.4 of this GIA, Transmission Provider shall compensate Interconnection Customer in accordance with any tariff or rate schedule filed by Transmission Provider and approved by the FERC.

ARTICLE 12. INVOICE

12.1 **General.** Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due, if any, for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this GIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 **Final Invoice**. Within six (6) months after completion of the construction of the Transmission Owner's Interconnection Facilities, Transmission Owner's System

Protection Facilities, Distribution Upgrades and the Network Upgrades, Transmission Owner shall provide an invoice of the final cost of the construction of the Transmission Owner's Interconnection Facilities, Transmission Owner's System Protection Facilities, Distribution Upgrades and the Network Upgrades and shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Owner shall refund, with interest (calculated in accordance with 18 C.F.R. Section 35.19a(a)(2)(iii), to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 **Payment**. Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by a Party will not constitute a waiver of any rights or claims that Party may have under this GIA.

12.4 **Disputes**. In the event of a billing dispute among the Parties, Transmission Provider shall continue to provide Interconnection Service under this GIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or Transmission Owner or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may or, at Transmission Owner's request upon Interconnection Customer's failure to pay, Transmission Owner, shall provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to another Party shall pay the amount due with interest calculated in accord with the methodology set forth in 18 C.F.R. § 35.19a(a)(2)(iii).

ARTICLE 13. EMERGENCIES

13.1 **Obligations.** Each Party shall comply with the Emergency Condition procedures of Transmission Provider, NERC, the Applicable Reliability Council, and Applicable Laws and Regulations.

13.2 **Notice.** Transmission Provider or Transmission Owner shall notify the other Parties promptly when it becomes aware of an Emergency Condition that affects the Transmission Owner's Interconnection Facilities or the Transmission or Distribution System, as applicable, that may reasonably be expected to affect Interconnection Customer's operation of the Generating Facility or the Interconnection Customer's Interconnection Facilities.

Interconnection Customer shall notify Transmission Provider and Transmission Owner, which includes by definition if applicable, the operator of a Distribution System,

promptly when it becomes aware of an Emergency Condition that affects the Generating Facility or the Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the Transmission or Distribution System, as applicable, or the Transmission Owner's Interconnection Facilities.

To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Provider's or Transmission Owner's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.

13.3 Immediate Action. Unless, in a Party's reasonable judgment, immediate action is required, the Party exercising such judgment shall notify and obtain the consent of the other Parties, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Generating Facility or the Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by Transmission Provider or otherwise regarding the Transmission or Distribution System, as applicable.

13.4 Transmission Provider and Transmission Owner Authority.

13.4.1 General. Transmission Provider or Transmission Owner may take whatever actions or inactions with regard to the Transmission System or the Transmission Owner's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Transmission System or the Transmission Owner's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

Transmission Provider or Transmission Owner shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Generating Facility or the Interconnection Customer's Interconnection Facilities. Transmission Provider or Transmission Owner may, on the basis of technical considerations, require the Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Generating Facility; implementing a reduction or disconnection pursuant to Article 13.4.2; directing Interconnection Customer to assist with blackstart (if available) or restoration efforts; or altering the outage schedules of the Generating Facility and the Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of Transmission Provider's or Transmission Owner's operating instructions concerning Generating Facility real power and reactive power output within the manufacturer's design limitations of the Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.4.2 Reduction and Disconnection. Transmission Provider or Transmission Owner may reduce Interconnection Service or disconnect the Generating Facility or the Interconnection Customer's Interconnection Facilities, when such reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment of Transmission Provider pursuant to the Tariff. When Transmission Provider can schedule the reduction or disconnection in advance, Transmission Provider shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider shall coordinate with Interconnection Customer and Transmission Owner using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to Interconnection Customer, Transmission Owner and Transmission Provider. Any reduction or disconnection shall continue only for so long as reasonably necessary pursuant to Good Utility Practice. The Parties shall cooperate with each other to restore the Generating Facility, the Interconnection Facilities, and the Transmission System to their normal operating state as soon as practicable consistent with Good Utility Practice.

13.5 **Interconnection Customer Authority**. Consistent with Good Utility Practice and this GIA and the GIP, Interconnection Customer may take whatever actions or inactions with regard to the Generating Facility or the Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Generating Facility or the Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and the Transmission Owner's Interconnection Facilities. Transmission Provider and Transmission Owner shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.6 **Limited Liability**. Except as otherwise provided in Article 11.6 of this GIA, no Party shall be liable to any other for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

13.7 **Audit**. In accordance with Article 25.3, any Party may audit the performance of another Party when that Party declared an Emergency Condition.

ARTICLE 14. REGULATORY REQUIREMENTS AND GOVERNING LAW

14.1 **Regulatory Requirements.** Each Party's obligations under this GIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith

seek, and if necessary assist the other Party and use its Reasonable Efforts to obtain such other approvals. Nothing in this GIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act, the Public Utility Holding Company Act of 2005, as amended, or the Public Utility Regulatory Policies Act of 1978.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this GIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

14.2.2 This GIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

ARTICLE 15. NOTICES

15.1 General. Unless otherwise provided in this GIA, any notice, demand or request required or permitted to be given by any Party to the other Parties and any instrument required or permitted to be tendered or delivered by a Party in writing to the other Parties shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Either Party may change the notice information in this GIA by giving five (5) Business Days written notice prior to the effective date of the change.

15.2 Billings and Payments. Billings and payments shall be sent to the addresses set out in Appendix F.

15.3 Alternative Forms of Notice. Any notice or request required or permitted to be given by any Party to the other and not required by this GIA to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

15.4 Operations and Maintenance Notice. Each Party shall notify the other Parties in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

ARTICLE 16. FORCE MAJEURE

16.1 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 A Party shall not be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4 and 5), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Parties in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone, facsimile or email notices given pursuant to this Article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise Reasonable Efforts to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

ARTICLE 17. DEFAULT

17.1 Default

17.1.1 General. No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this GIA or the result of an act or omission of another Party. Upon a Breach, the non-Breaching Party or Parties shall give written notice of such Breach to the Breaching Party with a copy to the other Party if one Party gives notice of such Breach. Except as provided in Article 17.1.2, the Breaching Party shall have thirty (30) Calendar Days from receipt of the Breach notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the Breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Breach notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 Termination. If a Breach is not cured as provided in this Article, or if a Breach is not capable of being cured within the period provided for herein, the non-Breaching Party or Parties shall terminate this GIA, subject to Article 2.3.2 of this GIA, by written notice to the Breaching Party, with a copy to the other Party if one Party gives notice of termination, and be relieved of any further obligation hereunder and, whether or not that Party(ies) terminates this GIA, to recover from the Breaching Party all amounts due hereunder, plus all other damages and remedies to which it is (they are) entitled at law or in equity. The provisions of this Article will survive termination of this GIA.

17.1.3 Cross-Default. Pursuant to Article 11.3 of this GIA, the Parties shall enter into a Facilities Service Agreement if the Transmission Owner has elected to fund the capital for the Network Upgrades and/or Transmission Owner's System Protection Facilities. Notwithstanding anything to the contrary contained in this GIA, a breach by Interconnection Customer of any provision, covenant, or other term or condition contained in the Facilities Service Agreement shall be considered a breach under this GIA. Such breach shall be subject to the terms of Article 17 of this GIA. If a default under this GIA results from the Interconnection Customer's breach of the Facilities Service Agreement and subsequent failure to cure, the Transmission Owner and Transmission Provider shall be entitled, but in no event required, to apply all rights and remedies available by reason of default under the Facilities Service Agreement and this GIA.

ARTICLE 18. LIMITATION OF LIABILITY, INDEMNITY, CONSEQUENTIAL DAMAGES AND INSURANCE

18.1 **Limitation of Liability.** A Party shall not be liable to another Party or to any third party or other person for any damages arising out of actions under this GIA, including, but not limited to, any act or omission that results in an interruption, deficiency or imperfection of Interconnection Service, except as provided in this Tariff. The provisions set forth in the Tariff shall be additionally applicable to any Party acting in good faith to implement or comply with its obligations under this GIA, regardless of whether the obligation is preceded by a specific directive.

18.2 **Indemnity.** To the extent permitted by law, an Indemnifying Party shall at all times indemnify, defend and hold the other Parties harmless from Loss.

18.2.1 Indemnified Party. If an Indemnified Party is entitled to indemnification under this Article 18 as a result of a claim by a non-Party, and the Indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.2, to assume the defense of such claim, such Indemnified Party may at the expense of the Indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.2.2 Indemnifying Party. If an Indemnifying Party is obligated to indemnify and hold any Indemnified Party harmless under this Article 18, the amount owing to the Indemnified Party shall be the amount of such Indemnified Party's actual Loss, net of any insurance or other recovery.

18.2.3 Indemnity Procedures. Promptly after receipt by an Indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.2 may apply, the Indemnified Party shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to

the Indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably satisfactory to the Indemnified Party. If the defendants in any such action include one or more Indemnified Parties and the Indemnifying Party and if the Indemnified Party reasonably concludes that there may be legal defenses available to it and/or other Indemnified Parties which are different from or additional to those available to the Indemnifying Party, the Indemnified Party shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Party or Indemnified Parties having such differing or additional legal defenses.

The Indemnified Party shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Party and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Party, or there exists a conflict or adversity of interest between the Indemnified Party and the Indemnifying Party, in such event the Indemnifying Party shall pay the reasonable expenses of the Indemnified Party, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Party, which shall not be reasonably withheld, conditioned or delayed.

18.3 Consequential Damages. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this GIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided; however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.4 Insurance. Transmission Owner and Interconnection Customer shall, at their own expense, maintain in force throughout the period of this GIA pursuant to 18.4.9, and until released by the other Party, the following minimum insurance coverages, with insurers authorized to do business or an approved surplus lines carrier in the state where the Point of Interconnection is located:

18.4.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the

Point of Interconnection is located.

18.4.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

18.4.3 Comprehensive Automobile Liability Insurance, for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers licensed for travel on public roads, with a minimum combined single limit of One Million Dollars ($1,000,000) each occurrence for bodily injury, including death, and property damage.

18.4.4 Excess Public Liability Insurance over and above the Employer's Liability, Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.4.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Parties, their parents, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this GIA against the Other Party Groups and provide thirty (30) Calendar Days' advance written notice to the Other Party Groups prior to anniversary date of cancellation or any material change in coverage or condition.

18.4.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

18.4.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a

Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this GIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by Transmission Owner and Interconnection Customer.

18.4.8 The requirements contained herein as to the types and limits of all insurance to be maintained by Transmission Owner and Interconnection Customer are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by Transmission Owner and Interconnection Customer under this GIA.

18.4.9 As of the date set forth in Appendix B, Milestones, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) Calendar Days thereafter, Interconnection Customer and Transmission Owner shall provide the other Party with certification of all insurance required in this GIA, executed by each insurer or by an authorized representative of each insurer.

18.4.10 Notwithstanding the foregoing, Transmission Owner or Interconnection Customer may self-insure to meet the minimum insurance requirements of Articles 18.4.1 through 18.4.8, to the extent it maintains a self-insurance program; provided that, Transmission Owner's or Interconnection Customer's senior secured debt is rated at investment grade, or better, by Standard & Poor's and that its self-insurance program meets minimum insurance requirements under Articles 18.4.1 through 18.4.8. For any period of time that a Transmission Owner's or Interconnection Customer's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.4.1 through 18.4.9. In the event that Transmission Owner or Interconnection Customer is permitted to self-insure pursuant to this article, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.4.9.

18.4.11 Transmission Owner and Interconnection Customer agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this GIA.

ARTICLE 19. ASSIGNMENT

19.1 **Assignment.** This GIA may be assigned by any Party only with the written consent of the other Parties; provided that a Party may assign this GIA without the consent of the other Parties to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this GIA; and provided further that Interconnection Customer shall have the right to assign this GIA, without the consent of either Transmission Provider or

Transmission Owner, for collateral security purposes to aid in providing financing for the Generating Facility, provided that Interconnection Customer will promptly notify Transmission Provider of any such assignment. Any financing arrangement entered into by Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify Transmission Provider of the date and particulars of any such exercise of assignment right(s), including providing Transmission Provider and Transmission Owner with proof that it meets the requirements of Article 11.5 and 18.4. Any attempted assignment that violates this Article is void and ineffective. Any assignment under this GIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

ARTICLE 20. SEVERABILITY

20.1 **Severability**. If any provision in this GIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this GIA; provided that if Interconnection Customer (or any non-Party, but only if such non-Party is not acting at the direction of either Transmission Provider or Transmission Owner) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

ARTICLE 21. COMPARABILITY

21.1 **Comparability**. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations including such laws, rules and regulations of Governmental Authorities establishing standards of conduct, as amended from time to time.

ARTICLE 22. CONFIDENTIALITY

22.1 **Confidentiality.** Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by a Party to another Party prior to the execution of this GIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential. The Parties shall maintain as confidential any information that is provided and identified by a Party as Critical

Energy Infrastructure Information (CEII), as that term is defined in 18 C.F.R. Section 388.113(c). Such confidentiality will be maintained in accordance with this Article 22.

If requested by the receiving Party, the disclosing Party shall provide in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 Term**.** During the term of this GIA, and for a period of three (3) years after the expiration or termination of this GIA, except as otherwise provided in this Article 22 or with regard to CEII, each Party shall hold in confidence and shall not disclose to any person Confidential Information. CEII shall be treated in accordance with Commission policy and regulations.

22.1.2 Scope. Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a non-Party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this GIA; or (6) is required, in accordance with Article 22.1.7 of this GIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this GIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the receiving Party that it no longer is confidential.

22.1.3 Release of Confidential Information. No Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, agents, consultants, or to non-parties who may be or are considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this GIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

22.1.4 Rights. Each Party retains all rights, title, and interest in the Confidential Information that it discloses to the receiving Party. The disclosure by a Party to the receiving Party of Confidential Information shall not be deemed a waiver by the disclosing Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 No Warranties. By providing Confidential Information, no Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to another Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 Standard of Care. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to another Party under this GIA or its regulatory requirements.

22.1.7 Order of Disclosure. If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires any Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the disclosing Party with prompt notice of such request(s) or requirement(s) so that the disclosing Party may seek an appropriate protective order or waive compliance with the terms of this GIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 Termination of Agreement. Upon termination of this GIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from another Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the requesting Party) or return to the requesting Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the requesting Party, except that each Party may keep one copy for archival purposes, provided that the obligation to treat it as Confidential Information in accordance with this Article 22 shall survive such termination.

22.1.9 Remedies**.** The Parties agree that monetary damages would be inadequate to compensate a Party for another Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the disclosing Party shall be entitled to equitable relief, by way of injunction or otherwise, if the receiving Party Breaches

or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the Breaching Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 Disclosure to FERC, its Staff or a State**.** Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 CFR § 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from a Party that is otherwise required to be maintained in confidence pursuant to this GIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Parties to this GIA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Parties to this GIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, any information that a disclosing Party claims is competitively sensitive, commercial or financial information under this GIA shall not be disclosed by the receiving Party to any person not employed or retained by the receiving Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the receiving Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the disclosing Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this GIA or as the Regional Transmission Organization or a Local Balancing Authority operator including disclosing the Confidential Information to a regional or national reliability organization. The Party asserting confidentiality shall notify the receiving Party in writing of the information that Party claims is confidential. Prior to any disclosures of that Party's Confidential Information under this subparagraph, or if any non-Party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the Party who received the Confidential Information from the disclosing Party agrees to promptly notify the disclosing Party in writing and

agrees to assert confidentiality and cooperate with the disclosing Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

ARTICLE 23. ENVIRONMENTAL RELEASES

23.1 Each Party shall notify the other Parties, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect another Party. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Parties copies of any publicly available reports filed with any Governmental Authorities addressing such events.

ARTICLE 24. INFORMATION REQUIREMENTS

24.1 **Information Acquisition**. Transmission Provider, Transmission Owner and Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 **Information Submission by Transmission Provider and Transmission Owner** The initial information submission by Transmission Provider to Interconnection Customer, with copy provided to Transmission Owner, shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include Transmission or Distribution System information, as applicable and available, necessary to allow Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise mutually agreed to by the Parties. On a monthly basis, Transmission Owner shall provide Interconnection Customer a status report on the construction and installation of Transmission Owner's Interconnection Facilities, Transmission Owner's System Protection Facilities, Distribution Upgrades and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 **Updated Information Submission by Interconnection Customer**. The updated information submission by Interconnection Customer to Transmission Provider, with copy to Transmission Owner, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Trial Operation. Interconnection Customer shall submit to Transmission Provider and Transmission Owner a completed copy of the Generating Facility data requirements contained in Appendix 1 to the GIP. It shall also include any additional information provided to Transmission Provider for the Interconnection Facilities Study. Information in this submission shall be the most current Generating Facility design or expected performance

data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, Interconnection Customer will work with a consultant mutually agreed to by Transmission Provider and Interconnection Customer to develop and supply a standard model and associated information.

If the Interconnection Customer's data is materially different from what was originally provided to Transmission Provider pursuant to the Interconnection Study Agreement between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on the Transmission System based on the actual data submitted pursuant to this Article 24.3. Interconnection Customer shall not begin Trial Operation until such studies are completed.

24.4 Information Supplementation. Prior to the Commercial Operation Date, the Parties shall supplement their information submissions described above in this Article 24 with any and all "as-built" Generating Facility information or "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. Interconnection Customer shall conduct tests on the Generating Facility as required by Good Utility Practice, such as an open circuit "step voltage" test on the Generating Facility to verify proper operation of the Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent (5 %) change in Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the responses in Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Generating Facility terminal or field voltages is provided. Generating Facility testing shall be conducted and results provided to Transmission Provider and Transmission Owner for each individual generating unit in a station.

Subsequent to the Commercial Operation Date, Interconnection Customer shall provide Transmission Provider and Transmission Owner any information changes due to equipment replacement, repair, or adjustment. Transmission Owner shall provide Interconnection Customer, with copy to Transmission Provider, any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Owner substation that may affect the Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

ARTICLE 25. INFORMATION ACCESS AND AUDIT RIGHTS

25.1 Information Access. Each Party (the "disclosing Party") shall make available to the other Parties information that is in the possession of the disclosing Party and is necessary in order for the other Parties to: (i) verify the costs incurred by the disclosing Party for which another Party is responsible under this GIA; and (ii) carry out its obligations and responsibilities under this GIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this GIA.

25.2 Reporting of Non-Force Majeure Events. A Party (the "notifying Party") shall notify the other Parties when the notifying Party becomes aware of its inability to comply with the provisions of this GIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this Article shall not entitle any Party receiving such notification to allege a cause for anticipatory breach of this GIA.

25.3 Audit Rights. Subject to the requirements of confidentiality under Article 22 of this GIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to the other Parties, to audit at its own expense the other Parties' accounts and records pertaining to the Parties' performance or the Parties' satisfaction of obligations under this GIA. Such audit rights shall include audits of the other Parties' costs, calculation of invoiced amounts, the Transmission Provider's efforts to allocate responsibility for the provision of reactive support to the Transmission or Distribution System, as applicable, the Transmission Provider's efforts to allocate responsibility for interruption or reduction of generation, and each Party's actions in an Emergency Condition. Any audit authorized by this Article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this GIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.4 Audit Rights Periods.

25.4.1 Audit Rights Period for Construction-Related Accounts and Records. Accounts and records related to the design, engineering, procurement, and construction of the Transmission Owner's Interconnection Facilities, Transmission Owner's System Protection Facilities, Distribution Upgrades and Network Upgrades shall be subject to audit for a period of twenty-four months following Transmission Owner's issuance of a final invoice in accordance with Article 12.2.

25.4.2 Audit Rights Period for All Other Accounts and Records. Accounts and records related to a Party's performance or satisfaction of all obligations under this GIA other than those described in Article 25.4.1 shall be subject to audit as

follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four (24) months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four (24) months after the event for which the audit is sought.

25.5 **Audit Results**. If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the Party or from whom the overpayment or underpayment is owed together with those records from the audit which support such determination.

ARTICLE 26. SUBCONTRACTORS

26.1 **General.** Nothing in this GIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this GIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this GIA in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

26.2 **Responsibility of Principal.** The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this GIA. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Transmission Provider or Transmission Owner be liable for the actions or inactions of Interconnection Customer or its subcontractors with respect to obligations of Interconnection Customer under Article 5 of this GIA. Any applicable obligation imposed by this GIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 **No Limitation by Insurance**. The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

ARTICLE 27. DISPUTES

27.1 **Submission.** In the event any Party has a dispute, or asserts a claim, that arises out of or in connection with this GIA or its performance, such Party (the "disputing Party") shall provide the other Parties with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the non-disputing Parties. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the non-disputing Parties' receipt of the Notice of Dispute, such claim or dispute shall be submitted for resolution in accordance with the dispute resolution procedures of the Tariff.

ARTICLE 28. REPRESENTATIONS, WARRANTIES AND COVENANTS

28.1 General. Each Party makes the following representations, warranties and covenants:

28.1.1 Good Standing. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this GIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this GIA.

28.1.2 Authority**.** Such Party has the right, power and authority to enter into this GIA, to become a Party hereto and to perform its obligations hereunder. This GIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 No Conflict. The execution, delivery and performance of this GIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 Consent and Approval. Such Party has sought or obtained, or, in accordance with this GIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this GIA, and it will provide to any Governmental Authority notice of any actions under this GIA that are required by Applicable Laws and Regulations.

ARTICLE 29. {RESERVED}

ARTICLE 30. MISCELLANEOUS

30.1 Binding Effect. This GIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.1.1 Reversion. If offered pursuant to an Agency Agreement under which this GIA is executed by Transmission Provider as agent for the relevant Transmission Owner, in the event that the relevant Agency Agreement terminates, any HVDC Service offered by Transmission Provider under this GIA shall revert to the relevant Transmission Owner and Transmission Provider shall be released from all

obligations and responsibilities under this GIA.

30.2 Conflicts. In the event of a conflict between the body of this GIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this GIA shall prevail and be deemed the final intent of the Parties.

30.3 Rules of Interpretation. This GIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this GIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this GIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this GIA or such Appendix to this GIA, or such Section to the GIP or such Appendix to the GIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this GIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including."

30.4 Entire Agreement. This GIA, including all Appendices and attachments hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this GIA. There are no other agreements, representations, warranties, or covenants, which constitute any part of the consideration for, or any condition to, any Party's compliance with its obligations under this GIA.

30.5 No Third Party Beneficiaries. This GIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 Waiver. The failure of a Party to this GIA to insist, on any occasion, upon strict performance of any provision of this GIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by any Party of its rights with respect to this GIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this GIA. Termination or Default of this GIA for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain Interconnection Service from Transmission Provider. Any waiver of this GIA shall, if requested, be provided in writing.

30.7 Headings. The descriptive headings of the various Articles of this GIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this GIA.

30.8 Multiple Counterparts. This GIA may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 Amendment. The Parties may by mutual agreement amend this GIA by a written instrument duly executed by all of the Parties.

30.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this GIA by a written instrument duly executed by all of the Parties. Such amendment shall become effective and a part of this GIA upon satisfaction of all Applicable Laws and Regulations.

30.11 Reservation of Rights. Transmission Provider shall have the right to make a unilateral filing with FERC to modify this GIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under Section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Transmission Owner and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this GIA pursuant to Section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this GIA shall limit the rights of the Parties or of FERC under Sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

30.12 No Partnership. This GIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership among or between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Parties.

IN WITNESS WHEREOF, the Parties have executed this GIA in multiple originals; each of which shall constitute and be an original GIA among the Parties.

Transmission Provider
Midcontinent Independent System Operator, Inc.

By: Jennifer Curran
Name: Jennifer Curran
Title: Vice President, System Planning & Chief Compliance Officer

DMK 4/23/2021

Transmission Owner
INTERNATIONAL TRANSMISSION COMPANY, a Michigan corporation

DocuSigned by:
By: Jon Jipping
16B37B2B6BB8435...
Name: Jon Jipping
Title: Executive Vice President & Chief Operating Officer

Interconnection Customer
Washtenaw Solar Energy LLC

DocuSigned by:
By: Michael Kaplan
9EE315750ZE0439...
Name: Michael Kaplan
Title: Vice President

LEGAL REVIEWED

Project No. J1062

APPENDICES TO GIA

Appendix A Interconnection Facilities, Network Upgrades, System Protection Facilities, Generator Upgrades and Distribution Upgrades

Appendix B Milestones

Appendix B-1 Pre-Certification Generation Test Notification Form

Appendix C Interconnection Details

Appendix D Security Arrangements Details

Appendix E Commercial Operation Date

Appendix F Addresses for Delivery of Notices and Billings

Appendix G Interconnection Requirements for a Non-synchronous Generating Facility

Appendix H Interconnection Requirements for Provisional GIA

Appendix I Requirements Applicable to Surplus Interconnection Service

Appendix A To GIA

Interconnection Facilities, System Protection Facilities, Distribution Upgrades, Generator Upgrades and Network Upgrades

1. Description of Generating Facility

Interconnection Customer shall install a 168 MVA facility 150 MW net, with all studies performed at or below these outputs. The Generating Facility is composed of fifty-six (56) PE FS3000MU solar inverter units rated at 3.0 MVA each. Interconnection Service provided under this agreement is 150 MW of conditional ERIS that will become 150 MW of ERIS and/or NRIS upon completion of all Network Upgrades, Common Use Upgrades and Affected System Upgrades listed under this GIA and transmission assumptions including those listed in Table A10-1.

Interconnection Customer shall install a switchyard with the appropriate protection equipment coordinated per Appendix C to this GIA. The Switchyard shall contain one (1) generator step-up transformer 345/34.5 kV 108/144/180 MVA, one (1) 345 kV circuit breaker connected in series fashion as shown in Exhibit A1.

Interconnection Customer shall install support as necessary to meet the FERC Order 827.

2. Interconnection Facilities

(a) Point of Interconnection. The Point of Interconnection shall be at the position DI at the J1062 345kV Interconnection station. The Point of Change of Ownership will be at the dead-end on the entrance structure at Transmission Owner's J1062 345kV Interconnection station. The Metering Point will be at J1062 collector station, compensated to the POI. See Exhibit A2.

(b) Interconnection Facilities (including metering equipment) to be constructed by Interconnection Customer. Interconnection Customer shall construct Interconnection Customer Interconnection Facilities and are detailed in Exhibit A1. These facilities shall include:

- 3.75 miles of 345 kV transmission line
- The interconnection customer should install billing metering equipment and OPGW. At least one bundle of OPGW will be required from J1062 345kV Interconnection station to J1062 Collector station to accommodate line current differential protection schemes.
- Customer shall install two SEL411L relays for protection of the 345kV line.
- Customer shall install two SEL-2506 devices to monitor the new 345 kV and 34.5 kV breaker status.
- Metering will be installed in the Generating Facility substation and compensated back to the POI.

(c) Transmission Owner Interconnection Facilities to be constructed by Transmission Owner. Transmission Owner will install an entrance structure and one set of disconnect switches to connect the generator at J1062 345kV Interconnection station. These upgrades are detailed in Exhibit A2.

Major Items:

- One (1) set of 345kV disconnect switches
- 594 feet of Bus, Wire and Cable
- Three (3) surge arresters

This TOIF is estimated to cost $544,494 with an accuracy of ± 20% and is detailed in Exhibit A6.

3. Network Upgrades

(a) Stand-Alone Network Upgrades to be installed by Transmission Owner. Transmission Owner shall construct J1062 345kV Interconnection station to support the interconnection. J1062 345kV Interconnection station will be a ring bus station with three sets of breakers. The station will be in Saline Township in Washtenaw County, Michigan about 26.9 miles from ITCT's Majestic 345kV station.

Major Items:

- Three (3) sets of 345kV Circuit Breakers
- Eight (8) sets of 345kV Disconnect Switches
- Six (6) 345kV Instrument Transformers
- Six (6) Surge Arresters
- Two (2) 345 kV Line Traps and Tuners
- 5095 feet of Bus, Wire, and Cable
- Two (2) 2205 Fiber Optic Current Differential Panel
- Three (3) 2100 Breaker Control Panel
- Two (2) 2201 Line Relaying Panel
- One (1) 2900 Synchronizing Control Panel
- One (1) SEL-2506

These facilities are estimated to cost $10,908,064 with ± 20% accuracy and are detailed in Exhibit A6.

(b) Network Upgrades to be installed by Transmission Owner. Transmission Owner will extend the Lemoyne - Majestic 345kV line to loop in the J1062 Interconnection station for transmission service. In addition, the system changes require ITCT to upgrade station equipment at Majestic 345kV station.

i. Extend the Lemoyne – Majestic 345kV line to loop in J1062 345kV

Interconnection station
ITCT will extend the Lemoyne - Majestic 345kV line by adding ~0.2 miles of 2-1431 ACSR 45/7 to loop in the J1062 Interconnection 345kV station for transmission service. ~26.9 miles of OPGW will be installed from ITCT's Majestic 345kV station to the J1062 station to support communications. This will require installing 4 new structures.

Major Items:
- Installation of ~0.2 (2*0.1) circuit miles of 2-1431 ACSR 45/7.
- Installation of ~0.1 circuit miles of shield wire to accommodate cut-in to J1062 station.
- Installation of ~26.9 miles of 48-Count OPGW.
- Removal of ~26.9 miles of existing shield wire from Majestic station to J1062 station.

These facilities are estimated to cost $5,274,000 with ± 20% accuracy and are detailed in Exhibit A6.

ii. Upgrade Majestic 345 kV station equipment
ITCT will replace current protection equipment with a line differential scheme operated with SEL-411L Relays.

Major Items:
- Installation of 200 feet of Bus, Wire and Cable
- Installation of One (1) RD2205 411L Line Relay Panel
- Removal of Two (2) Wave Traps and Tuners
- Removal of 122 feet of Bus, Wire, and Cable
- Removal of Two (2) 2205 411L Line Relaying Panels

These facilities are estimated to cost $252,456 with ± 20% accuracy and are detailed in Exhibit A6.

(c) Shared Network Upgrade(s) to be funded by Interconnection Customer. None.

4. System Protection Facilities

(a) System Protection Facilities not listed in Section 2 or 3 to be constructed by Interconnection Customer. None.

(b) System Protection Facilities not listed in 2 or 3 to be constructed by Transmission Owner. None.

5. Distribution Upgrades

(a) Distribution Upgrades to be constructed by Transmission Owner. None.

6. Contingency List See Exhibit A10.

7. Affected System Upgrades List Interconnection Customer is responsible to enter into Facilities Construction Agreements and/or Multi-Party Facilities Construction Agreement with Affected System Owner for the following upgrades:

First Energy Lemoyne station

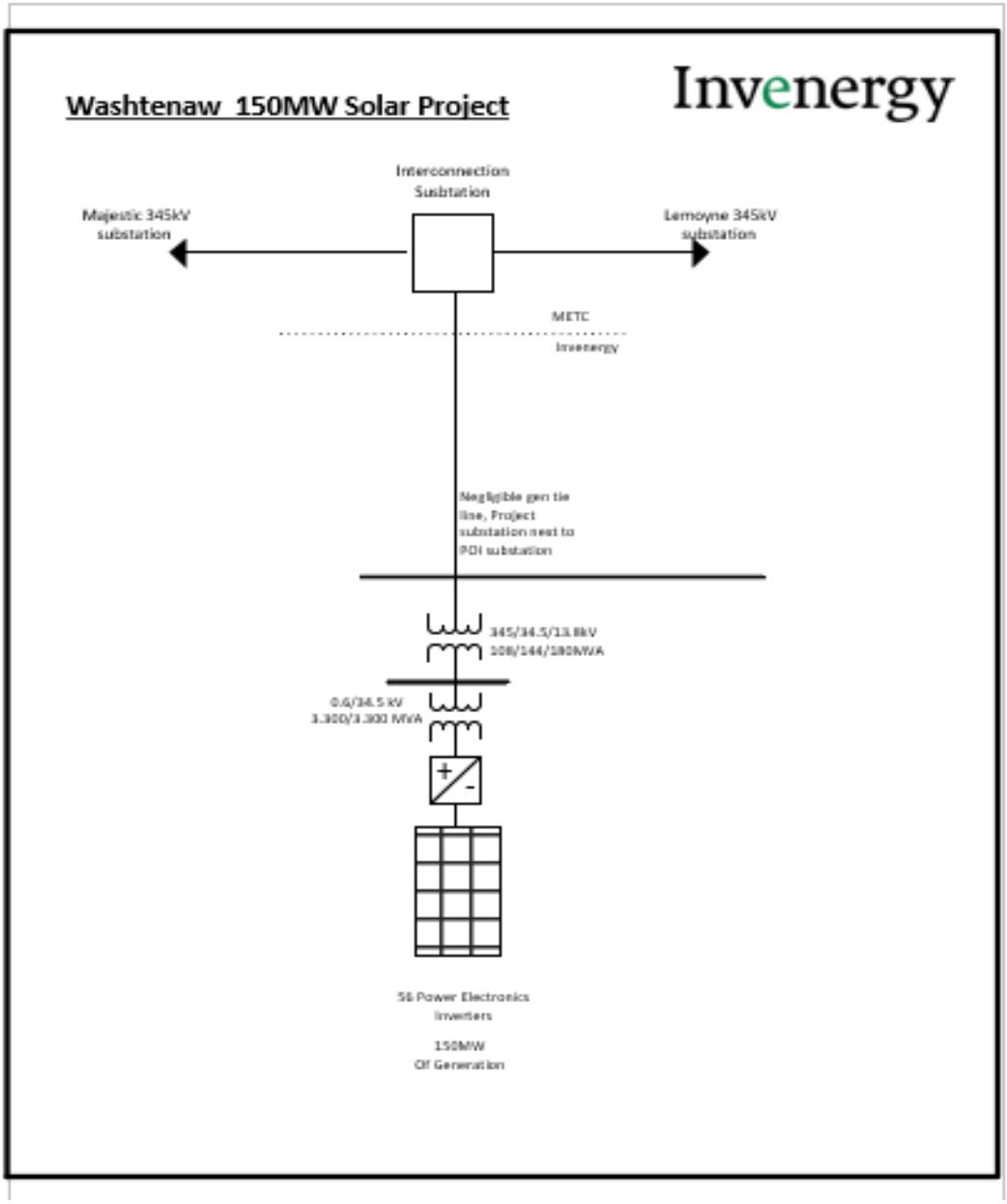
- Dual 421 Line Relaying with UPLC for DCB and transfer trip via PLC.
- Dual Frequency Wave Traps and Tuners (X & Z phases)

8. Exhibits – The following exhibits are included:

A1. Interconnection Customer One-Line and Site Map
A1-1: Interconnection Customer One-Line Diagram
A1-2: Interconnection Project Site Map
A2. Transmission Owner One-Line
A3. General Arrangement Drawings
A4. Transmission Owner Plan and Profile
A5. Facilities to be Constructed by Transmission Owner
A6. Detailed Costs of Facilities to be Constructed by Transmission Owner
A7. Network Upgrades to be Constructed by Interconnection Customer
A8. Details of Transmission Owner Facilities to be Constructed by Interconnection Customer
A9. Facilities Subject to Transmission Owner Reimbursement
A10. Contingent Facilities
A11. Interconnection Customer Milestones
A12. Construction and Coordination Schedules
A13. Permits, Licenses, Regulatory Approvals and Authorization
A14. Interconnection and Operating Guidelines

Original Sheet No. 88

Exhibit A1: Interconnection Customer One-Line and Site Map
A1-1: Interconnection Customer One-Line Diagram



A1-2: Interconnection Project Site Map

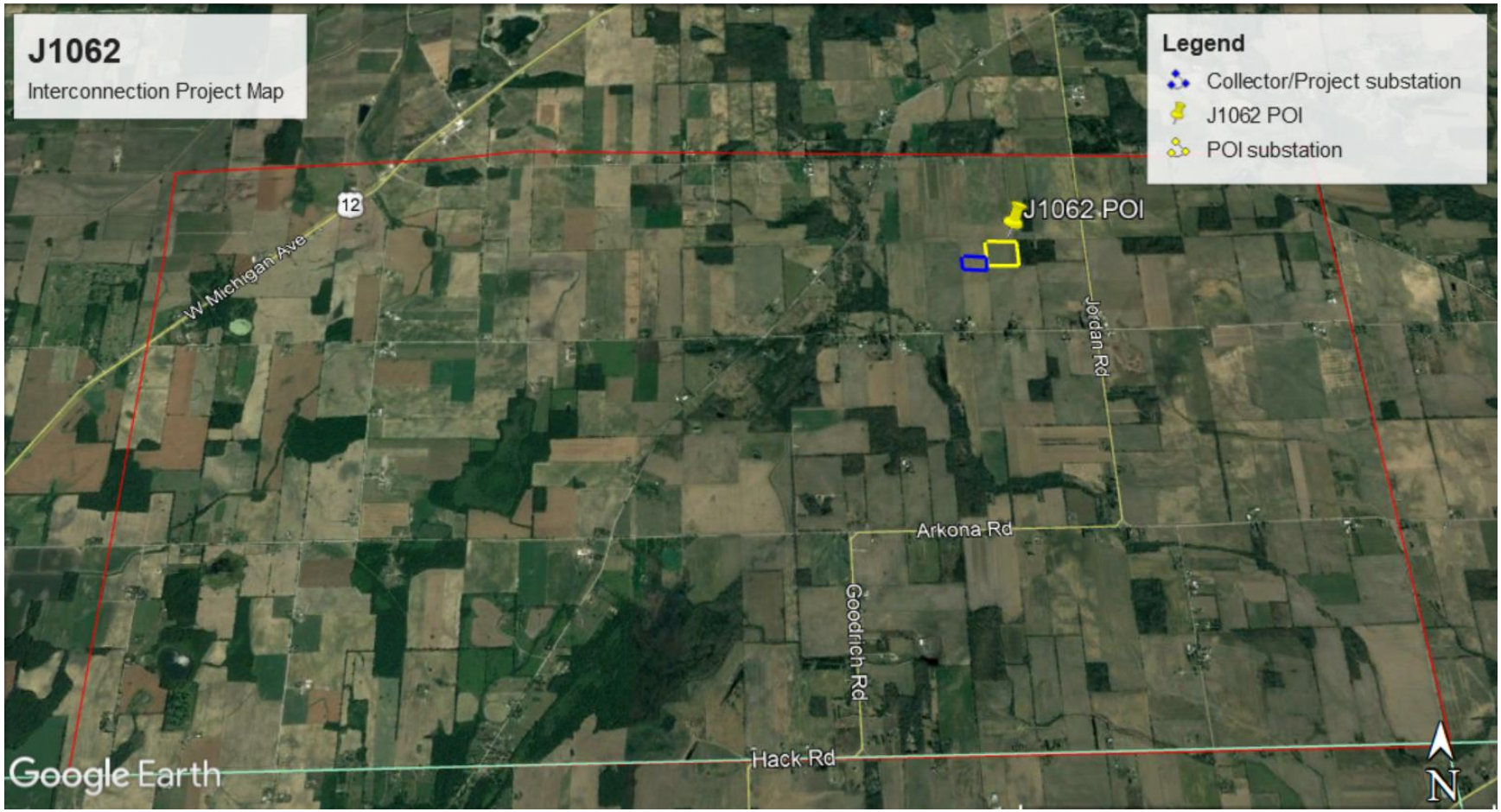


Exhibit A2: Transmission Owner One-Line

CUI//CEII MATERIAL – DO NOT RELEASE

Exhibit A3: General Arrangement Drawings

CUI//CEII MATERIAL – DO NOT RELEASE

Exhibit A4: Transmission Owner Plan and Profile

CUI//CEII MATERIAL – DO NOT RELEASE

Exhibit A5: Facilities to be Constructed by Transmission Owner

Type	Facilities to be Constructed by the Transmission Owner	Cost Estimate
Transmission Owner Interconnection Facilities	Add Position DI as TOIF	$ 544,494
Network Upgrade 1	Construct J1062 Interconnection station	$ 10,908,064
Network Upgrade 2	Extend Lemoyne - Majestic 345kV line to loop in J1062 Interconnection station	$ 5,274,000
Network Upgrade 3	Upgrade Majestic 345kV station equipment	$ 252,456
	TOTAL	**$ 16,979,014**

Exhibit A6: Detailed Costs of Facilities to be Constructed by Transmission Owner

Table A6-1 Add Position DI as TOIF

Engineering, Drafting, & Project Management	$ 42,000
Material	$ 179,755
Construction & Construction Oversight	$ 231,990
Overheads	$ 90,749
Total	$ 544,494

Table A6-2 Construct J1062 Interconnection Station

Engineering, Drafting, & Project Management	$ 492,000
Material	$ 4,320,677
Construction & Construction Oversight	$ 4,277,376
Overheads	$ 1,818,011
Total	$ 10,908,064

Table A6-3 Extend Lemoyne - Majestic 345kV to loop in J1062 Interconnection

Engineering, Drafting, & Project Management	$ 259,000
Material	$ 1,400,000
Construction & Construction Oversight	$ 2,696,000
Land Acquisition	$ 17,000
Other Costs	$ 23,000
Overheads	$ 879,000
Total	$ 5,274,000

Table A6-4 Upgrade Majestic 345kV Station Equipment

Engineering, Drafting, & Project Management	$ 52,000
Material	$ 64,000
Construction & Construction Oversight	$ 94,380
Overheads	$ 42,076
Total	$ 252,456

Exhibit A7: Network Upgrades to be Constructed by Interconnection Customer

None.

Exhibit A8: Details of Transmission Owner Facilities to be Constructed by Interconnection Customer

None.

Exhibit A9: Facilities Subject to Transmission Owner Reimbursement

Type	Facilities to be Constructed by the Transmission Owner	Cost Estimate
Network Upgrade 1	Construct J1062 Interconnection station	$ 10,908,064
Network Upgrade 2	Extend Lemoyne - Majestic 345kV line to loop in J1062 Interconnection station	$ 5,274,000
Network Upgrade 3	Upgrade Majestic 345kV Station Equipment	$ 252,456
	TOTAL	**$ 16,434,520**

If Interconnection Customer fails to achieve Commercial Operation of the Generating Facility by the Commercial Operation Date indicated in Appendix B Milestones of this GIA for reasons other than Transmission Owner delay of the In-Service Date, interest due to Interconnection Customer, under Article 11.4 of the GIA, for funding of Network Upgrade costs will not accrue for dates beyond that Commercial Operation Date.

Interconnection Customer funding for Network Upgrades is estimated at **$16,434,520**. Network Upgrades shall be eligible for up to 100% reimbursement per Attachment FF of the Tariff.

Exhibit A10: Contingent Facilities

Higher queue and/or same DPP group study Interconnection Requests that may create contingencies pursuant to Article 11.3.1 are listed in tables below. Table A10-1 describes transmission assumptions modeled in the studies that were deemed necessary to allow for the Interconnection Service as described in Appendix A of this GIA and is not related to Article 11.3.1, i.e., does not describe projects associated with a higher queued and/or same DPP group study Interconnection Request. Nevertheless, if the transmission assumptions are not completed or significantly modified, the Interconnection Service granted under this GIA may be restricted until such time as the Interconnection Customer funds a study to determine the applicable ERIS and NRIS level that results due to the changes in Table 1.

The list of higher-queued and/or same DPP group study projects in Tables A10-2 and A10-3, not yet in service, were included in the interconnection study for queue project J1062. However, a project's inclusion in the System Impact Study does not necessarily mean that these facilities would be contingencies for the Interconnection Customer's Generating Facility. In the event that any of the higher queued and/or same DPP group study generators were to drop out, then the Interconnection Customer may be subject to restudy pursuant to Article 11.3.2.

Table A10-1 Transmission Assumptions

MTEP ID	Facility	Facility IDs	Description	Expected Completion Date	Status	Note
	NONE					A10 analysis

Table A10-2 Higher Queued Projects

MISO Higher Queued Project	Service Type	TO	County, State	Point of Interconnection	Summer MW (Net)	Fuel Type	Status	Comments
J228	NRIS	METC	Mason, MI	Ludington Substation	70	Hydro	Under Construction	expected 5/31/2021
J466	NRIS	ITCT	Huron, MI	Stein 345 kV Substation	30	Battery Storage	Under Construction	Not In-service
J419	NRIS	ITCT	Washtenaw, MI	Milan 120kV Substation	100	Solar	Under Construction	Not In-service
J538	NRIS	METC	Hillsdale, MI	Moore Rd to Dowling 138kV line	150	Wind	DPP-2016-FEB-MI	expected 2/1/2021
J717	NRIS	CONS	Isabella, MI	Edenville Junction-Warren 138 kV line	200.1	Wind	2017-FEB-East (ITC)	expected 1/8/2021
J728	NRIS	CONS	Isabella, MI	Edenville Junction-Warren 138 kV line	186.3	Wind	2017-FEB-East (ITC)	expected 1/8/2021
J758	NRIS	METC	Calhoun, MI	Verona-Foundry 138 kV	200	Solar	2017-FEB-East (ITC)	Not In-service
J793	NRIS	ITC Transmission	St. Clair , MI	Belle River - Fitz #2 345 kV Line Tap	1209	Combined Cycle	2017--AUG-EAST (ITC)	Not In-service
J796	NRIS	METC	Shiawassee , MI	Goss 138kV Substation	189	Solar	2017--AUG-EAST (ITC)	in service (partial 50MW, the rest expected 8/1/21 & 11/1/21)
J799	NRIS	ITC Transmission	Washtenaw , MI	Milan - Pioneer 120kV Line Tap	149	Solar	2017--AUG-EAST (ITC)	Not In-service
J806	NRIS	Consumers Energy	Calhoun , MI	Rice Creek - Vrooman 138kV Line Tap	91	Solar	2017--AUG-EAST (ITC)	Not In-service
J832	NRIS	METC	Cheboygan , MI	Port Calcite - Riggsville 138kV Line	50	Solar	2017--AUG-EAST (ITC)	Not In-service
J833	NRIS	ITC Transmission	Washtenaw , MI	Milan-Pioneer 120kV line tap	124.95	Solar	2017--AUG-EAST (ITC)	Not In-service
J857	NRIS	METC	Calhoun , MI	Verona - Foundry 138 kV Line Tap	150	Solar	2017--AUG-EAST (ITC)	Not In-service
J875	NRIS	METC	Lenawee , MI	Par - Raisin Road 138kV Line	535	Solar	2017--AUG-EAST (ITC)	Not In-service

Table A10-3 Similar Queued Projects

MISO Similar Queued Project #	Service Type	TO	County, State	Point Of Interconnection	Fuel Type	Pmax (MW)	ERIS/NRIS
J984	NRIS	METC	Gratiot County, MI	Nelson Rd. 345 kV Substation	Wind	200	200
J996	NRIS	METC	Lenawee County, MI	Beecher - Moraco 138kV Line	Solar	80	80
J1043	NRIS	METC	Montcalm County, MI	Vergennes - Nelson Rd 345 kV Line Tap	Wind	374.4	374.4
J1062	NRIS	ITC Transmission	Washtenaw County, MI	Majestic - Lemoyne 345 kV Line Tap	Solar	150	150
J1071	NRIS	METC	Oceana County, MI	Donaldson 138 kV Substation	Solar	100	100
J1088	NRIS	METC	Shiawassee County, MI	Cornell - Layton 138 kV Line Tap	Solar	150	150
J1089	NRIS	METC	Shiawassee County, MI	Cornell - Bell Rd 138 kV Line Tap	Solar	170	170
J1090	NRIS	METC	Ingham County, MI	Tompkins - Churchill Jct 138 kV Line Tap	Solar	90	90
J1172	NRIS	METC	Genesee County, MI	Dort - Garfield 138 kV Line Tap	Solar	50	50
J1178	NRIS	METC	Eaton County, MI	Oneida 138 kV Substation	Solar	65	65

Exhibit A11: Interconnection Customer Milestones

The details below are for reference only. The binding milestones are listed in Appendix B.

Customer Milestones

Item	Date
Initial Energization (Backfeed Date)	6/1/2023
Commercial Operations Date	12/31/2023

Cash Flow Schedule

The following table identifies the major activities of the project based on the Transmission Owner provided schedule. The cash flow is a one possible suggestion and needs to be agreed upon by the Interconnection Customer and Transmission Owner. This information is provided for reference purposes only. The actual schedule shall be negotiated during GIA negotiation and listed in Appendix B.

Item No.	Description of the Major Activity	Date	Cash flow from Customer to ITC
1	Within 45 days of GIA execution and/or FERC Approval (Network Upgrades).	6/15/2021	100% Security in form acceptable to the TO
2	Within 45 days of GIA execution and/or FERC Approval (Transmission Owner Interconnection Facilities – TOIF)	6/15/2021	100% Cash
3	Design and Procurement	2/2/2022	0%
4	Construction Begins	4/2/2022	0%
5	Backfeed	6/1/2023	0%

Notes:

1. A suggested cash flow from the Interconnection Customer to Transmission Owner is based on the major activities started Transmission Owner.
2. Amount of cash flow is the percentage of total project cost as agreed by the Customer and Transmission Owner.
3. Dates for payments are based on the proposed schedule in the FS by the Transmission Owner. If there are mutually agreed changes in the schedule, payment dates will be adjusted accordingly.
4. E&P funds will be reflected in Appendix B of the cash milestone in the GIA to the extent that they are applicable.

Exhibit A12: Construction and Coordination Schedules

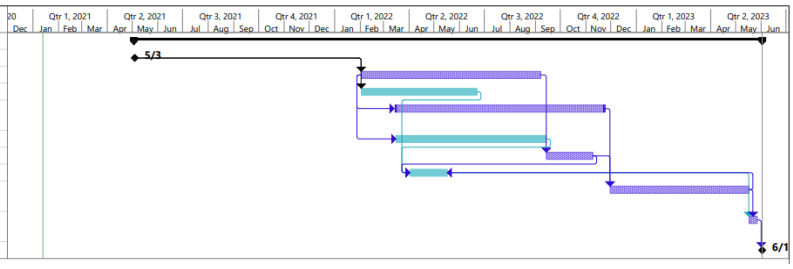
This exhibit is provided for reference purpose only. Actual schedule shall be negotiated during GIA negotiation and listed in Appendix B.

This exhibit includes project schedules for the various construction activities. The project schedules include brief descriptions of construction activities, outage requirements, and overall progress. Exhibits are labeled as follows:

The project schedules are prepared based on the normal activities and time frame required by the Transmission Owner. It may not match with the Interconnection Customer requirements and in-service dates. At the time of executing an Interconnection Agreement (IA) a project schedule will be developed that will integrate with other work/projects performed by the Transmission Owner.

The construction sequence provided in the Exhibit is prepared based on the inputs from the Transmission Owner. Actual outages (dates and durations) are not known and will impact the construction sequence. Following major construction stages are defined.

ID		Task Name	Duration	Start	Finish
0		**J1062 Interconnection**	**544 days**	**Mon 5/3/21**	**Thu 6/1/23**
1		GIA Signed	1 day	Mon 5/3/21	Mon 5/3/21
2		Substation Design	155 days	Wed 2/2/22	Tue 9/6/22
3		Overhead Line Design	100 days	Wed 2/2/22	Tue 6/21/22
4		Major Materials - Substation	180 days	Wed 3/16/22	Tue 11/22/22
5		Major Materials - Line	130 days	Wed 3/16/22	Tue 9/13/22
6		Contractor Selection	40 days	Wed 9/14/22	Tue 11/8/22
7		Overhead Line Construction	32 days	Sat 4/2/22	Mon 5/16/22
8		Substation Construction	120 days	Wed 11/30/22	Tue 5/16/23
9		Testing and Commissioning	8 days	Wed 5/17/23	Fri 5/26/23
10		Energize	1 day	Thu 6/1/23	Thu 6/1/23



Notes:

1. Line outage dates, indicated in the schedule, are placeholders only. The system outage schedule will not be accurately known until a later date. If outages cannot be achieved by the indicated date or sooner, the schedule will be delayed accordingly.
2. The Transmission Owner proposed schedule dates may not match or align with the Customer requested in-service date.

Exhibit A13: Permits, Licenses, Regulatory Approvals and Authorization

The Transmission Owner will be responsible for all permits and community approvals for station projects on fee owned property. Planning approvals and permitting typically take between four and ten months. The process could take longer if unforeseen obstacles are encountered. Since field surveys and design has not begun it is unclear what permits will be required for the project.

Permits/Approvals that may be required for the project include, but are not limited to, the following:

	Permit Description	Required for this Project	Entity Responsible for Obtaining Permit
1	Building Permit	Yes	Transmission Owner
2	Driveway Permit	Yes	Transmission Owner
3	MDEQ Wetland Permit	Maybe	Transmission Owner
4	MDEQ NPDES Permit	Maybe	Transmission Owner
5	MDEQ Floodplain Permit	Maybe	Transmission Owner
6	Soil Erosion Permit	Maybe	Transmission Owner
7	Drain Commissioner Permit	Maybe	Transmission Owner
8	Township Planning Commission Approval	Maybe	Transmission Owner
9	SHPO Approval	No	Transmission Owner
10	US Fish & Wildlife Threatened & Endangered Species	Maybe	Transmission Owner
11	MDNR Threatened & Endangered Species	Maybe	Transmission Owner

Exhibit A14: Interconnection and Operating Guidelines

If required by Good Utility Practice to do so, Transmission Owner or Transmission Operator may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Owner's or Transmission Operator's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Appendix:

1. The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

2. Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission or Distribution System, as applicable;

3. When the interruption or reduction must be made under circumstances which do not allow for advance notice, the Transmission Owner or Transmission Operator shall notify the Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

4. Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, the Transmission Owner or Transmission Operator shall notify the Interconnection Customer in advance regarding the timing of such scheduling and further notify the Interconnection Customer of the expected duration. The Transmission Owner or Transmission Operator shall coordinate with the Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to the Interconnection Customer, Transmission Owner, Transmission Operator and the Transmission Provider;

5. The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Generating Facility, Interconnection Facilities, and the Transmission or Distribution System, as applicable to their normal operating state, consistent with system conditions and Good Utility Practice.

Voltage Guidelines

Reactive power, voltage regulation and operating requirements will be per Transmission Operator (TOP) and Transmission Provider directives. Interconnection Customer will operate the Generating Facility to a voltage schedule target of 356 kV (1.032 pu) within a bandwidth of +/- 5kV (0.014 pu) at the Point of Interconnection (POI). The Interconnection Customer will regulate the Generating Facility's voltage to the specified voltage set-point within the defined bandwidth stated above using an automatic voltage controller. The Generating Facility shall be designed to eliminate reactive power injection into or withdrawal from the system, measured at the high side of the generator substation, when the Generating Facility is not producing real power. This includes reactive power injection caused by collector systems.

The above voltage schedule is subject to change. If the need for a change is identified, it will be done within the limits of the GIA provisions stated in Section 9.6 and the Generating Facility's power factor design criteria. If a schedule change is needed, appropriate written documentation of the change will be provided to the Interconnection Customer.

The Generating Facility shall not cause voltage flicker in accordance with Section 9.7.6. In addition to the standards outlined in Section 9.7., the perception of light flicker in the short-term index (Pst) shall not exceed 1, per IEEE Standard 1453 measurements.

The Interconnection Customer is required to have a generator operator available for 24/7 communication with the TOP. The TOP may, at any time request a variance from the schedule in response to system operating/security requirements.

Appendix B To GIA

Milestones

1. Selected Option pursuant to Article 5.1: Interconnection Customer selects the Standard Option as described in Article 5.1.1. Articles 5.1.2, 5.1.3 and 5.1.4 shall not apply to this GIA.

2. Milestones: The description and date entries listed in the following tables are provided solely for the convenience of the Parties in establishing their applicable Milestones consistent with the provisions of this GIA and the GIP.

A. Interconnection Customer Milestones

No.	Description	Date
1.	Pick one: Provide initial payment to Transmission Owner (GIA 11.5). Provide initial payment to Transmission Owner (GIA 11.5) in the form of Letter of Credit for the amount of $16,434,520 (100% of total Transmission Owner Network Upgrade costs) and Cash Payment in the amount of $544,494 (100% of the Transmission Owned Interconnection Facilities .	Within the later of a) 45 Calendar Days of the execution of the GIA by all Parties, or b) 45 Calendar Days of acceptance by FERC if the GIA is filed unexecuted and the payment is being protested by Interconnection Customer, or c) 45 Calendar Days of the filing if the GIA is filed unexecuted and the initial payment is not being protested by Interconnection Customer.
2.	Provide Certificate of Insurance (GIA 18.4.9).	The earlier of the construction work commencement date or the milestone date; thereafter, within 90 Calendar Days of end of fiscal year or insurance renewal date.
3.	i) Provide to Transmission Provider evidence of continued Site Control after execution of this GIA (GIP 7.2.2). ii) Provide evidence of one or more of the following milestones being achieved: (1) execution of contract for (a) fuel supply or transport; (b) cooling water supply; (c) engineering procurement of major equipment or construction; (d) execution	As may be agreed to by the Parties. Within 180 Calendar Days of Effective Date.

	of a contract for the sale of electric energy or capacity from the Generating Facility, or a statement signed by an officer or authorized agent of Interconnection Customer attesting that the Generating Facility is included in an applicable state resource adequacy plan; or other information that Transmission Provider deems to be reasonable evidence that the Generating Facility will qualify as a designated network resource; or (2) documentation of application for state or local air, water, land, or federal nuclear or hydroelectric permits and that the application is proceeding per regulations (GIP 11.3).	
4.	Pre-construction meeting.	As may be agreed to by the Parties.
5.	Provide initial design and specifications for Interconnection Customer's Interconnection Facilities to Transmission Owner and Transmission Provider for comment (GIA 5.10.1).	180 Calendar Days prior to initial synchronization date.
6.	Provide final design and specifications for Interconnection Customer's Interconnection Facilities to Transmission Owner and Transmission Provider for comment (GIA 5.10.1).	90 Calendar Days prior to initial synchronization date.
7.	Deliver to Transmission Owner and Transmission Provider "as-built" drawings, information and documents regarding Interconnection Customer's Interconnection Facilities (GIA 5.10.3).	Within 120 Calendar Days of Commercial Operation Date.
8.	Notify Transmission Provider and Transmission Owner in writing of Local Balancing Authority where Generating Facility is located (GIA 9.2).	Three months prior to Initial Synchronization Date.
9.	Pre-energization meeting.	As may be agreed to by the Parties.
10.	Initial Synchronization Date.	6/1/2023
11.	Commercial Operation Date.	12/31/2023*
12.	Interconnection Customer shall provide the Parties with notice on the status of the Generating Facility, including COD, under Article 15 of this GIA and shall also send such notice by email to ResourceIntegration@misoenergy.org. Notification shall include Interconnection Customer's name, and as applicable Market Participant(s) name(s), and project number.	6 months prior to Initial Synchronization Date.
13.	Interconnection Customer shall provide notice to the Parties of a test plan in advance of conducting tests for the Generating Facility. The notice shall be in the form below and should be provided under Article 15	5 Business Days prior to testing.

	of this GIA, and a copy of such notice should be emailed to ResourceIntegration@misoenergy.org.	
14.	In the event the Interconnection Customer makes any modifications to the design of the site layouts or interconnection facility routes after execution of this GIA, Interconnection Customer shall notify the Parties of such changes immediately upon identifying the need for such changes. After providing such notification, the Interconnection Customer shall provide to Transmission Provider evidence of continued Site Control for land sufficient to accommodate the changes in site layouts and/or interconnection facility routes (GIP 7.2.2).	90 Calendar Days after Interconnection Customer provides notice to Parties.

* Modified from the original Commercial Operation Date of December 31, 2021 contained in the Interconnection Request.

B. Transmission Owner Milestones

No.	Description	Date
0.	Transmission Owner to enter Network Upgrade information into Transmission Provider's MTEP database and model on demand.	10 Business Days after Effective Date.
1.	Provide Certificate of Insurance (GIA 18.4.9).	The earlier of the construction work commencement date or the milestone date; within 90 Calendar Days of end of fiscal year or insurance renewal date.
2.	• Commence design of Interconnection Facilities (GIA 5.5 et seq.). • Commence equipment procurement.	As agreed to by the Parties (after completion of Interconnection Facilities Study, receipt of written authorization from Interconnection Customer and Interconnection Customer's deposit of security.
3.	Commence construction of Interconnection Facilities (GIA 5.6 et seq.).	As agreed to by the Parties (after receiving approval of Governmental Authority, receipt of written authorization and security from Interconnection Customer).
4.	Comment on Interconnection Customer's final design	Within 30 Calendar Days of

	and specifications.	Interconnection Customer's submission of final design and specifications.
5.	Deliver to Interconnection Customer and Transmission Provider "as-built" drawings, information and documents regarding Transmission Owner's Interconnection Facilities (GIA 5.11).	Within 120 Calendar Days of Commercial Operation Date.
6.	Provide Interconnection Customer final cost invoices (GIA 12.2 *et seq.*).	Within (6) six months of completion.
7.	Refund overpayment of estimated costs (GIA 12.2).	90 Calendar Days prior to initial synchronization date. Refunds within 30 Calendar Days.
8.	In-Service Date/Backfeed Date.	6/1/2023

C. Affected System Owner Milestones

Task	**Date Due**
First Energy Lemoyne station ▪ Dual 421 Line Relaying with UPLC for DCB and transfer trip via PLC. ▪ Dual Frequency Wave Traps and Tuners (X & Z phases)	Prior to Commercial Operation Date

D. Transmission Provider Milestones

No.	**Description**	**Date**
1.	Transmission Provider to determine conditional limit for interconnection service.	Prior to Commercial Operation.
2.	Transmission Provider to provide Notice to the Parties when unconditional interconnection service is achieved. Unconditional Service requires completion of MTEP Contingent Facilities listed in Exhibit A10 and all Interconnection Studies .	Within 30 Calendar days of unconditional service being achieved.

Appendix B-1
To GIA
Pre-Certification Generation Test Notification Form

The following form would need to be submitted to MISO Real Time Operations at least five (5) Business Days prior to the first date of testing.

Project Number:

Project Name:

Point of Interconnection:

Dispatcher Contact Information:

Date	Start Time (in EST)	End Time (in EST)	Expected MW Output	Expected MVAR Output (Only needed if beyond normal power factor)

Appendix C To GIA
Interconnection Details

1. GENERAL INTERCONNECTION AND OPERATING GUIDELINES

1.1 Applicable Standards. In addition to applicable design standards identified in the GIA, Interconnection Customer agrees to comply with the most recent Transmission Owner substation/transmission/protection design guides, standards, and specifications, where applicable, for the design of and procurement for this interconnection. The Transmission Owner design guides, standards, and specifications are available upon request.

In the event that such Transmission Owner design guides, standards or specifications do not address a particular item or issue, Interconnection Customers shall use any other nationally or regionally recognized standard, guide or specification. In the event that there is a conflict between any other standard, guide or specification used by Interconnection Customers and Transmission Owner's design guides, standards and material/construction specifications, Transmission Owner's design guides, standards and specifications shall apply.

1.2 Communication Requirements. Interconnection Customer shall provide analog and digital signals including hardened voice communications, as requested by the Transmission Owner and/or the Transmission Provider for RTU/frame relay/or public switched telephone systems, as further defined during detailed engineering and design of the Interconnection Facilities. Interconnection Customer agrees to transmit these signals to Transmission Owner's control building or to such other location as specified by the Transmission Owner during the detailed design of the Interconnection Facilities and Network Upgrades. Transmission Owner shall provide Interconnection Customer with the necessary substation information at the Transmission Owner's signals demarcation point. Interconnection Customer will pay all costs associated with receiving such information from Transmission Owner. The specific location of the demarcation point will be established during the detailed design of the Interconnection Facilities.

1.3 Metering Requirement. Interconnection Customer shall be responsible for the all of the interconnection metering.

1.4 Grounding Requirements. Interconnection Customer shall design, install, and maintain grounding facilities to ground the Interconnection Customer's Interconnection Facilities, in accordance Applicable Reliability Standards and Good Utility Practice. Interconnection Customer shall be responsible for detailed modeling and evaluation of the interconnected grounding system at the location of the Transmission Owner's Interconnection Facilities and Interconnection Customer's Interconnection Facilities. If Transmission Owner so chooses, Transmission Owner shall have the right to approve the grounding system design to insure that the grounding system properly protects the Transmission Owner's Interconnection Facilities.

1.5 Transmission Line and Substation Connection Configurations. The Parties agree that the connections between Interconnection Customer's Interconnection Facilities and Transmission Owner's Interconnection Facilities will be as configured in Exhibit A2-2. Exact transmission line locations will be developed by Transmission Owner during the detailed design and regulatory process. Interconnection Customer shall provide the space necessary for the Transmission Owner's placement of the transmission line facilities.

1.6 Unit Stability Requirements. Interconnection Customer agrees to operate its Generating Facility in accordance with the stability requirements identified in the Interconnection Evaluation Study and Interconnection Facilities Study reports, or their equivalent, prepared for this interconnection and which have been posted on the Transmission Provider OASIS. Interconnection Customer agrees to operate its Generating Facility within the operating requirements of the Transmission System, and the rules of the NERC, Reliability Coordinator and Transmission Provider.

1.7 Equipment Ratings. Transmission Owner will determine the individual equipment ratings for specific Transmission Owner's Interconnection Facilities and Network Upgrades during the detailed design of the facilities. Interconnection Customer shall size the Interconnection Customer's Interconnection Facilities using Applicable Reliability Standards, Good Utility Practice and the information provided in the Interconnection Evaluation Study in order that the Interconnection Customer's Interconnection Facilities appropriately coordinate with the Transmission Owner's Interconnection Facilities.

1.8 Short Circuit Requirements. Transmission Owner will determine the required short circuit ratings for all Transmission Owner's Interconnection Facilities and Network Upgrades during the detailed design of such items. Interconnection Customer agrees to provide appropriately sized or short circuit-rated Interconnection Customer's Interconnection Facilities comparable to those required by Transmission Owner using Applicable Reliability Standards, Good Utility Practice and the information provided in the Interconnection Evaluation Study.

1.9 Synchronizing Requirements. In addition to requirements defined in Section 2 of this Appendix C, Transmission Owner will furnish Transmission System bus potentials that may be used by Interconnection Customer for synchronizing the combined Generating Facility to Transmission Owner's Transmission System. These potentials will be provided to the Interconnection Customer at the Transmission Owner's signal demarcation point, as necessary.

1.10 Generation Control Requirements. In addition to the requirements set forth elsewhere in this Appendix C, the Generating Facility shall be designed and installed with voltage and var controls. These controls shall comply with any Applicable Reliability Standards, industry standards or Good Utility Practice. The Interconnection Customer, prior to completion of the Generating Facility, shall contact Transmission Owner for the information required to properly design the phase of the Generating Facility. Interconnection Customer further agrees to comply with

any control requirements as specified in the Interconnection Facilities Study and as directed by the Transmission Operator, and shall design and construct each generating unit of its Generating Facility, if more than one unit, to include the capability to install power system stabilizers if later required.

1.11 Power Factor Design Criteria. Interconnection Customer's Generating Facility is designed to be capable of maintaining power factor between 0.95 leading to 0.95 lagging at the Point(s) of Interconnection. Interconnection Customer agrees to operate its Generating Facility, as directed, to produce or absorb reactive power at the Point(s) of Interconnection within the design limitations of the Generating Facility.

1.12 Energization, Inspection and Testing Requirements. Before final approval for interconnection is given per Appendix E, Interconnection Customer shall demonstrate to the Transmission Provider and Transmission Owner, through witnessed tests and/or certified test documentation, that the combined Generating Facility will not have adverse impact on the operation of the Transmission System. Such tests and inspections shall include pre-energization testing of equipment connected to the transmission bus, protection and control systems and pre-commercial testing of the governor, excitation and/or power system stabilizer controls. Specific test requirements and documentation need to be arranged with Transmission Owner prior to tests being performed. Protection and control systems include, but are not limited to, AC auxiliary, DC systems, relaying systems, potential and current circuits, and communication systems.

1.13 If applicable, the unique requirements, if any, of the Transmission Owner to which the Generating Facility will be physically interconnected. None identified.

1.14 Other. Interconnection Customer shall provide all necessary easements over all property owned, leased or otherwise controlled by Interconnection Customer, including easements for ingress/egress by Transmission Owner for access to all Transmission Owner's Interconnection Facilities and Network Upgrades that are on the property of Interconnection Customer. Specific real estate requirements will be determined during the final design. Interconnection Customer agrees to grant Transmission Owner reasonable easements in a form that is acceptable to Transmission Owner. It is expressly understood and agreed that Transmission Owner may, during the term of the GIA, make changes to its Transmission System. Interconnection Customer agrees to make any modifications, additions or changes to the Interconnection Customer's Interconnection Facilities that are reasonably necessary or required as a result of such change, modification or addition to Transmission Owner's Transmission System and at Interconnection Customer's sole cost and expense.

2. SPECIFIC SYSTEM PROTECTION REQUIREMENTS

General. The Transmission Owner will construct a protective relaying scheme to protect the Transmission System from faults occurring on the Interconnection Customer's Interconnection Facilities or the Generating Facility, and from faults occurring on the

Transmission Owner's Interconnection Facilities and Transmission System. Interconnection Customer will be responsible for providing protection for the Generating Facility and all associated equipment from faults occurring on its facilities, and from faults occurring on the Transmission Owner's Transmission System. E.g. When the only source behind a fault on the transmission line is the generator, local line relaying may not trip and will require the generator to clear the fault.

Firmware changes on interconnecting relays need to be coordinated with and receive approval by the Transmission Owner prior to being placed into service.

Transmission Owner has identified the following specific requirements to ensure prompt removal of any contribution of the Generating Facility to any short circuit occurring on the Transmission System and not otherwise isolated by the Transmission Owner equipment:

2.1 **Frequency Protection (IEEE 81).** Over-frequency protection for the Generating Facility shall be set at the discretion of Interconnection Customer. Under-frequency protection shall be in accordance with the, applicable Reliability First or its successor Standards/Guides as applicable and as amended from time to time.

2.2 **Interconnection Customer Breaker Failure Protection (IEEE 50BF).** Interconnection Customer agrees to have breaker failure protection as an integral part of the redundant relaying protection in support of its breakers on the high side of the generator step-up transformers. This relay protection shall be coordinated with Transmission Owner in order to trip adjacent substation breakers, in the event the generator breaker fails to successfully open for any reason.

2.3 **Synchronism Check Relay (IEEE 25).** Interconnection Customer shall sync check the Generating Facility to the Transmission System across the Interconnection Customer-owned breaker installed on the high side of the generator step-up transformers. The Transmission Owner will provide bus voltages to be used for synchronism. Each generating unit of the Generating Facility, if more than one unit, shall include automatic or manual synchronization of the unit to Transmission Owner's Transmission System.

2.4 **Bus Differential Protection (IEEE 87).** Interconnection Customer shall provide Line Current Differential relay with fiber to be connected into an identical Transmission Owner Current Differential relay which will overlap the bus or step-up transformer's protection. This is to accomplish a bus differential protection scheme to provide coordinated bus differential protection of Transmission Owner's bus.

2.5 **Protection Redundancy.** In accordance with Good Utility Practice, Interconnection Customer shall design protection schemes such that no single component failure will prevent the isolation of faults and failed equipment. Interconnection Customer acknowledges that meeting this requirement generally means providing redundant or backup protective schemes, with separate sensing sources, separate trip paths, dual trip coils on breakers, separate control power supplies, etc., provided that Interconnection Customer will provide only one battery system.

3. SPECIFIC TELEMETRY REQUIREMENTS.

General: Telemetry is required for the monitoring and status of Interconnection Customer's and Transmission Owner's equipment. Details of the specific telemetry requirements will be provided during the detailed design of the facilities. Interconnection Customer shall install and pay the installation cost and monthly communication costs of all required telemetry for the Generating Facility. In general, Transmission Owner requires continuous telemetry of the following:

3.1 Appropriate relaying status of all installed relay equipment.

3.2 Status of all circuit breaker(s) capable of disconnecting the Generating Facility from the Transmission Owner's Transmission System.

3.3 Instantaneous MW and MVAR of the Generating Facility.

3.4 Instantaneous revenue quality MW and MVAR; and cumulative revenue quality MWhr and MVARhr at all (or possibly corrected to) Points of Interconnection with Transmission Owner and from the Generating Facility.

3.5 Status of auxiliary station service circuit breaker(s).

3.6 Instantaneous 345 bus voltage(s).

3.7 Transfer trip communication and generation site transfer trip communication status.

3.8 Changes in energy production of the Generating Facility.

3.9 Other telemetry as required and mutually agreed upon by the Interconnection Customer and Transmission Owner.

4. SPECIFIC OPERATIONAL REQUIREMENTS.

4.1 **System Protection Facilities (Relays As They Relate To Operations).** Interconnection Customer shall report all generator protective relay events to the Transmission Owner system control center, immediately following Interconnection Customer's discovery of the event. Interconnection Customer shall provide status indication of automatic voltage regulator equipment and any other items that are identified during the detailed design.

4.2 **Communication Requirements.** Interconnection Customer will provide any communication protocols for proper function between Interconnection Customer's operating systems and Transmission Owner's operating systems. Interconnection Customer shall pay all fees for such communication facilities and associated monthly services, as necessary, for the Generating Facility.

4.3 **Data Reporting Requirements.** Interconnection Customer shall supply all information regarding events and status of equipment within the Facility upon request

for any event that noticeably affects the operation of the Transmission System. Interconnection Customer shall provide outage schedules, daily/hourly load profiles, and other data upon request of Transmission Owner.

4.4 Emergency Operations, Including System Restoration and Black Start Arrangements. Interconnection Customer is not able to operate as a Black Start Unit as of the effective date of this GIA. However, in accordance with Good Utility Practice, Interconnection Customer agrees to participate when called upon by Transmission Provider or Transmission Owner, in Transmission Owner's Black Start Plan for the Generating Facility and Transmission Owner's Transmission System, as well as any verification testing.

4.5 Identified Must-Run Conditions. None noted for this Generating Facility.

4.6 Specific Transmission Requirements of Nuclear Units to Abide by All NRC Requirements and Regulations. Not applicable to this interconnection.

4.7 Stability Requirements, Including Output. Interconnection Customer agrees to comply with the requirements of the reliability coordinator, Transmission Dispatch Center or ("TDC"), Transmission Provider and/or Transmission Owner in the operation of the Generating Facility.

4.8 Limitations of Operations in Support of Emergency Response. Interconnection Customer agrees to comply with the requirements of the reliability coordinator, Transmission Dispatch Center or ("TDC"), Transmission Provider and/or the Transmission Owner in the operation of the Generating Facility.

5. Transmission Owner shall provide the "as-built" drawings, information and documents regarding the Transmission Owner's Interconnection Facilities pursuant to Article 5.11 of the GIA.

6. In accordance with Section 9.4 of the GIA, the operating limits established for the Generating Facility under this GIA shall be as provided by Transmission Provider each quarter, as described in Appendix A. Any operating guides necessary following Commercial Operation will be established in accordance with Section 9.3.

7. Use of SPS or Operating Guide. Implementation of an Operating Guide will constitute an interim solution that will permit Interconnection Customer to obtain conditional Interconnection Service until planned for Network Upgrades are constructed. Any Operating Guide will be subject to the approval of the Transmission Owner and Transmission Provider. Minimum requirements for an Operating Guide are as indicated below.

- Transmission Owner will control Transmission Owner's breaker(s) protecting the Interconnection Customer Interconnection Facilities located at the Generating Facility and shall be able to trip the Interconnection Customer's Generating Facility.
- Protection schemes must be tested and operative.

- Interconnection Customer will operate its Generating Facility as directed by the Transmission Provider and the Transmission Owner.
- A termination date consistent with completion of Network Upgrades will be mutually agreed to as part of all Operating Guides accepted by the Transmission Owner and the Transmission Provider.

Transmission Owner does not allow the addition of an SPS to the Transmission Owner's system. The Transmission Owner will also not allow the addition of an SPS on a system, including the Generating Facility, where the purpose of that SPS is to mitigate a constraint on the Transmission Owner's system.

Appendix D
To GIA

Security Arrangements Details

Infrastructure security of Transmission or Distribution System equipment and operations, as applicable, and control hardware and software is essential to ensure day-to-day Transmission and Distribution System reliability and operational security. The Commission will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission or Distribution System, as applicable, to comply with the recommendations provided by Governmental Authorities regarding Critical Energy Infrastructure Information ("CEII") as that term is defined in 18 C.F.R. Section 388.113(c) and best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

Appendix E
To GIA

Commercial Operation Date

This Appendix E is a part of this GIA between Transmission Provider, Transmission Owner and Interconnection Customer.

[Date]

Midcontinent Independent System Operator, Inc.
Attn: Director, Transmission Access Planning
720 City Center Drive
Carmel, IN 46032

Re: _____ Generating Facility

Dear _____:

On **[Date] [Interconnection Customer]** has completed Trial Operation of Unit No. ___. This letter confirms that **[Interconnection Customer]** commenced commercial operation of Unit No. ___ at the Generating Facility, effective as of **[Date plus one Calendar Day]**.

Thank you.

[Signature]

[Interconnection Customer Representative]

cc: Transmission Owner

Appendix F
To GIA

Addresses for Delivery of Notices and Billings

Notices:

Transmission Provider:

MISO
Attn: Director, Transmission Access Planning
720 City Center Drive
Carmel, IN 46032

Transmission Owner:

International Transmission Company
Attn: Legal Department – Commercial Contracts
27175 Energy Way
Novi, MI 48377
Fax: (248) 946-3552

Interconnection Customer:

Washtenaw Solar Energy LLC
General Counsel
One South Wacker Suite 1800
Chicago IL 60606
Interconnection-notices@invenergy.com
GeneralCounsel@invenergy.com
312-224-1400

Billings and Payments:

Transmission Provider:

MISO
Attn: Director, Transmission Access Planning
720 City Center Drive
Carmel, IN 46032

Transmission Owner:

International Transmission Company
P.O. Box 673963
Detroit, MI 48267-3963

Interconnection Customer:

Washtenaw Solar Energy LLC
Asset Management
One South Wacker Suite 1800
Chicago IL 60606
Interconnection-notices@invenergy.com
312-224-1400

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

Transmission Provider:

Phone: (317) 249-5700
Email: misotap@misoenergy.org or
MISOTransmissionAccessPlanning@misoenergy.org

Transmission Owner:

International Transmission Company
Attn: Planning Department – Vice President
27175 Energy Way
Novi, MI 48377

Interconnection Customer:

Washtenaw Solar Energy LLC
General Counsel
One South Wacker Suite 1800
Chicago IL 60606
Interconnection-notices@invenergy.com
GeneralCounsel@invenergy.com
312-224-1400

Appendix G
Interconnection Requirements for a Non-synchronous Generating Facility

Appendix G sets forth requirements and provisions specific to a non-synchronous generating facility. All other requirements of this GIA continue to apply to non-synchronous generating facility interconnections.

A. Technical Standards Applicable to a Non-synchronous Generating Facility

i. Abnormal Voltage Ride-Through Capability

A non-synchronous generating facility shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below.

1. Non-synchronous generating facilities are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4-9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the non-synchronous generating facility substation location, as determined by and documented by the transmission provider. The maximum clearing time the non-synchronous generating facility shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the non-synchronous generating facility may disconnect from the transmission system. A non-synchronous generating facility shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the GSU.

2. This requirement does not apply to faults that would occur between the non-synchronous Generator terminals and the high side of the GSU.

3. Momentary cessation (ceasing to inject current into the transmission grid during a fault without mechanical isolation) is prohibited in North American Electric Reliability Corporation (NERC) reliability standard PRC-024 no trip zone.

4. Non-synchronous generating facility inverters may not trip or cease to inject current for momentary loss of synchronism. Any inverter may trip if the phase lock loop is unable to regain synchronism 150 milliseconds after loss of synchronism.

5. Non-synchronous generating facilities may be tripped after the fault period if this action is intended as part of a Special Protection System.

6. Non-synchronous generating facilities may meet the abnormal voltage ride-through requirements of this standard by the dynamic performance capability of the generators, by installing additional equipment (*e.g.* Static VAr Compensator) within the non-synchronous generating facility or by a combination of generator performance and additional equipment.

7. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G abnormal voltage ride-through Standard are exempt from meeting the Appendix G abnormal voltage ride-through Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G abnormal voltage ride-through Standard.

ii. Power Factor Design Criteria (Reactive Power)

The following reactive power requirements apply only to a newly interconnecting non-synchronous generating facility that has completed a System Impact Study as of the effective date of the Final Rule establishing the reactive power requirements for non-synchronous generators in section 9.6.1 of this GIA (Order No. 827). A non-synchronous generating facility to which this provision applies shall maintain a factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all Generating Facilities in the Local Balancing Authority on a comparable basis, measured at the high side of the generator substation. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by Transmission Provider, or a combination of the two. Interconnection Customer shall not disable power factor equipment while the non-synchronous generating facility is in operation. Non-synchronous generating facilities shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system.

iii. Supervisory Control and Data Acquisition (SCADA) Capability

The non-synchronous generating facility shall provide SCADA capability to transmit data and receive instructions from Transmission Provider to protect system reliability. Transmission Provider and Interconnection Customer shall determine what SCADA information is essential for the proposed non-synchronous generating facility, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

iv. Transient Data Recording Equipment for Facilities above 20 MW

Non-synchronous generating facilities with generating capacities of more than 20 MW must monitor and record data for all frequency ride-through events, transient low-voltage disturbances that initiated reactive current injection, reactive current injection or momentary cessation for transient high-voltage disturbances, and inverter trips. The data may be recorded and stored in a central plant control system. The following data must be recorded:

Plant Level

(1) Plant three-phase voltage, current and power factor
(2) Status of ancillary reactive devices
(3) Status of all plant circuit breakers
(4) Status of plant controller

(5) Plant control set points
(6) Status of main plant transformer no load taps
(7) Status of main plant transformer tap changer (if applicable)
(8) Protective relay trips (relay target data)

Inverter Level Data
(1) Frequency, current, and voltage during frequency ride-through events
(2) Voltage and current during momentary cessation for transient high-voltage events (when used)
(3) Voltage and current during reactive current injection for transient low or high-voltage events
(4) Inverter alarm and fault codes
(5) DC current
(6) DC voltage

The data must be time synchronized to a one millisecond level of resolution. All data except phase angle measuring unit data must be sampled at least every 10 milliseconds.

The non-synchronous generating facility shall store this data for a minimum of 60 calendar days. The non-synchronous generating facility, upon request from MISO or the transmission owner, shall make this data available within 10 calendar days of the request.

v. <u>Protection Settings</u>

A non-synchronous generating facility, while complying with the under-frequency and over-frequency ride through requirements, shall use accurately calculated and filtered frequency measurement over a time window to set frequency protection and should not use an instantaneously calculated value to set frequency protection.

A non-synchronous generating facility, while complying with the under-voltage and over-voltage ride through requirements should use filtered Root-Mean-Squared (RMS) voltage measurement to set voltage protection.

Inverter rate-of-change-of-frequency (ROCOF) protection shall be disabled unless an equipment limitation exists that requires the inverter to trip on high ROCOF.

Appendix H – Not Applicable
Interconnection Requirements for Provisional GIA

Provisional Agreement

This GIA is being provided in accordance with Section 11.5 of the Transmission Provider's GIP, which provides among other things, that an Interconnection Customer may request that Transmission Provider provide Interconnection Customer with a provisional GIA that limits the transfer of energy by Interconnection Customer commensurate with that allowed for Energy Resource Interconnection Service. Interconnection Customer requested Transmission Provider to provide a provisional GIA for limited operation at the discretion of Transmission Provider based upon the results of available studies (by Interconnection Customer and by Transmission Provider).

A Provisional Interconnection Study, the results of which are posted on the confidential portion of the Transmission Provider's internet website, was performed by Transmission Provider in order to confirm the facilities that are required for provisional Interconnection Service and to require them to be in place prior to commencement of service under the GIA.

Interconnection Customer represents that the Interconnection Customer facilities (including Network Upgrades, Interconnection Facilities, Distribution Upgrades, System Protection Upgrades and/or Generator Upgrades) that are necessary to commence provisional Interconnection Service and meet the requirements of NERC, or any applicable regional entity for the interconnection of a new generator are in place prior to the commencement of generation from the Generating Facility and will remain in place during the term of the service. The requisite Interconnection Studies were performed for the Generating Facility. Interconnection Customer shall meet any additional requirements (including reactive power requirements) pursuant to the results of applicable future Interconnection System Impact Studies. Until such time as the applicable Interconnection Studies and any identified facilities are completed, the output of the Generating Facility will operate within the output limit prescribed in a future, if applicable, operating guide.

The maximum permissible output of the Generating Facility under Appendix A will be updated by Transmission Provider on a quarterly basis, determined in accordance with Section 11.5 of the GIP, by finding the transfer limit of energy commensurate with the analysis for Energy Resource Interconnection Service ("ERIS"). This study shall be performed assuming the system topology represented by the base cases used to calculate Available Flowgate Capability, as described in Attachment C of the Tariff, with dispatch and optimization algorithms posted on the MISO internet site and operation above those limits will be deemed as unauthorized use of the Transmission System and subject to provisions in the Tariff surrounding that use.

Use of interim operating guide

Implementation of interim operating guide, if applicable, will constitute an interim solution that will permit Interconnection Customer to operate the Generating Facility under conditional Interconnection Service until planned Network Upgrades are constructed. Any interim operating

guide will be subject to the approval of Transmission Owner and Transmission Provider. Minimum requirements for an interim operating guide are as indicated below.

* Transmission Operator will have control of breaker(s) dedicated to the Generating Facility and will be able to trip the Interconnection Customer's Generating Facility
* Protection schemes must be tested and operative
* Interconnection Customer will provide continuous communication capability with the Generator Operator
* Interconnection Customer and the owner of the Existing Generating Facility will enter into an operating agreement or similar agreement which designates, among other things, the responsibilities and authorities of each of the parties and shall be subject to the acceptance of Transmission Provider and Transmission Owner.
* A termination date consistent with completion of construction of Network Upgrades will be included as part of all operating guides accepted by Transmission Owner and Transmission Provider.

Interconnection Customer assumes all risks and liabilities with respect to changes, which may impact the Generator Interconnection Agreement including, but not limited to, change in output limits and responsibilities for future Network Upgrade and cost responsibilities that have not yet been identified on the direct connect Transmission System as well as all affected Transmission, Distribution or Generation System(s) including non-Transmission Provider Systems. Such upgrades will be determined pursuant to the Tariff and Policies in effect at the time of the Interconnection Studies.

Appendix I – Not Applicable
Requirements Applicable to Surplus Interconnection Service

Where this GIA provides for Surplus Interconnection Service, Interconnection Customer acknowledges, agrees to, and will be required to operate under the following conditions:

1) The combined Real-Time Offers, including Energy and Operating Reserves, of the Generating Facility and the Existing Generating Facility with which Interconnection Customer has an executed Energy Displacement Agreement must be less than or equal to Interconnection Service limit (MW, MVAR, MVA output) provided in Exhibit I-1 (Monitoring and Consent Agreement) (hereinafter, "Interconnection Service limit").
   In the event that the sum of the simultaneous energy output of the Surplus Interconnection Service Generating Facility and the Existing Generating Facility exceeds such Interconnection Service limit, MISO reserves the right to curtail and/or disconnect the Generating Facility immediately.

   In the event that the sum of the emergency and/or economic maximum offer limits of the Generating Facility and the Existing Generating Facility exceeds the Interconnection Service limit, MISO reserves the right to curtail and/or disconnect the Generating Facility immediately.

2) The total MW, MVAR, MVA output at the Point of Interconnection resulting from the combined output of the Generating Facility with Surplus Interconnection Service and the Existing Generating Facility with which Interconnection Customer has an executed Energy Displacement Agreement shall not at any time exceed the Interconnection Service limit.

3) The Existing Generating Facility with which Interconnection Customer has an executed Energy Displacement Agreement is not relieved of any applicable requirements under the RAR of the Tariff.

4) The Interconnection Customer shall submit to the Transmission Provider a report by the seventh Calendar Day of each month showing the prior month's output, by 15 minute increment, the combined real-time offers and cleared energy injection. The Existing Generating Facility and the Interconnection Customer shall cooperate consistent with other provisions in the Tariff to the extent necessary to ensure accuracy of the report. Transmission Provider shall provide a template for this report.

Exhibit I-1 (Completed Monitoring and Consent Agreement - Appendix 11 of the GIP)

Exhibit I-2 (Completed Energy Displacement Agreement - Appendix 12 of the GIP)

Appendix B: FERC Waiver

191 FERC ¶ 61,060
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Mark C. Christie, Chairman;
Willie L. Phillips, David Rosner,
Lindsay S. See, and Judy W. Chang.

Washtenaw Solar Energy LLC Docket No. ER25-1424-000

ORDER GRANTING WAIVER REQUEST

(Issued April 21, 2025)

1. On February 26, 2025, pursuant to Rules 207(a)(5) and 212 of the Commission's Rules of Practice and Procedure,[1] Washtenaw Solar Energy LLC (Washtenaw) filed a request for waiver of: (1) section 4.4.4 in Attachment X (Generator Interconnection Procedures (GIP)) of Midcontinent Independent System Operator, Inc.'s (MISO) Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff); and (2) Article 2.3.1 of the Generator Interconnection Agreement among Washtenaw as interconnection customer; International Transmission Company, doing business as ITC Transmission (ITC Transmission), as transmission owner; and MISO as transmission provider (Washtenaw GIA). Washtenaw requests that the Commission grant waiver to allow for a 24-month extension of the commercial operation deadline for its planned 150 MW solar generating facility (Project), from December 31, 2026 to December 31, 2028. As discussed below, we grant Washtenaw's waiver request.

I. Background

2. GIP section 4.4.4 provides, in relevant part, that:

> Consistent with Article 2.3.1 of the GIA, once that GIA is executed or filed unexecuted, if the Generating Facility fails to reach Commercial Operation by the Commercial Operation Date set forth in the GIA, such Commercial Operation Date as set forth in the GIA may be extended by Interconnection Customer for a period up to three (3) consecutive years, after

[1] 18 C.F.R. §§ 385.207(a)(5), 385.212 (2024).

> which Transmission Provider shall terminate the GIA if the Generating Facility has still failed to reach Commercial Operation.[2]

3. Article 2.3.1 of the Washtenaw GIA provides, in relevant part, that:

> This GIA shall be terminated by Transmission Provider if the Generating Facility or a portion of the Generating Facility fails to achieve Commercial Operation by the Commercial Operation Date established in accordance with Section 4.4.4 of Attachment X, including any extension provided thereunder . . . .[3]

4. Appendix B of the Washtenaw GIA establishes milestones for the interconnection of the Project, including a commercial operation date of December 31, 2023.[4] Pursuant to GIP section 4.4.4 and Article 2.3.1 of the Washtenaw GIA, MISO must terminate the Washtenaw GIA if the Project fails to achieve commercial operation by December 31, 2026.

5. Washtenaw states that it is developing the Project in Saline Township and Bridgewater Township, Michigan, and that the Project will interconnect to the transmission system owned by ITC Transmission and operated by MISO.[5] Washtenaw explains that it has invested approximately $10 million in developing the Project, including securing thousands of acres under solar easements, conducting environmental studies, completing engineering studies and design diligence, and ordering long-lead items like the main power transformer. Washtenaw states that it has also contracted with Consumers Energy Company for the Project's output to serve load.

6. Washtenaw states that, shortly after executing the Washtenaw GIA in 2021, Saline Township passed an ordinance increasing the required utility-scale solar setbacks from 100 feet to 600 feet from all road rights-of-way and non-contiguous property lines.[6] Washtenaw states that this ordinance drastically reduced the Project's buildable area and

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[2] MISO, Tariff, attach. X, § 4.4.4 (167.0.0). Capitalized terms used but not otherwise defined in this order have the meanings ascribed to them in the Tariff.

[3] Washtenaw GIA, art. 2.3.1.

[4] *Id.*, app. B, Interconnection Customer Milestone No. 11.

[5] Waiver Request at 1, 4.

[6] *Id.* at 5.

has prevented Washtenaw from being able to secure a local permit to construct the Project. Accordingly, Washtenaw explains that it cannot begin construction activities for the Project until it receives the local permit, which Washtenaw states it will not receive with sufficient time to reach commercial operation by December 31, 2026, as required in the Washtenaw GIA.

7. Washtenaw states that it is actively working to mitigate the local setback ordinance and obtain the local permit by contracting for additional land and rights-of-way, continuing project development activities, and engaging with Saline Township to revert to the previous setback requirements.[7] Washtenaw asserts that, if it does not reach a resolution with Saline Township to obtain a local permit, it will apply for a state permit in the summer of 2025. Washtenaw explains that, pursuant to a recent state law, which became effective on November 29, 2024, the Michigan Public Service Commission is able to issue permits through a new state permit process if a project cannot get a local permit or faces local ordinances incompatible with state requirements.[8] Washtenaw further explains that, if it applies for a state permit, it anticipates receiving the permit in the third quarter of 2026 and that the Project's construction and testing activities will take approximately 18 months after issuance of the permit.

II. Waiver Request

8. Washtenaw requests a limited waiver of GIP section 4.4.4 and Article 2.3.1 of the Washtenaw GIA to allow a 24-month extension of the Project's commercial operation deadline, from December 31, 2026 to December 31, 2028.[9] Washtenaw asserts that, absent the requested waiver, it faces termination of the Washtenaw GIA, thereby jeopardizing significant development efforts including, among other things, ordering long-lead time equipment, funding network upgrades, and actively pursuing the necessary permits to complete the Project. Washtenaw asserts that its waiver request satisfies the Commission's criteria for granting waiver.

9. First, Washtenaw argues that it acted in good faith to diligently pursue the Project.[10] Washtenaw contends that, due to significant permit challenges resulting from the local setback ordinance, Washtenaw needs a commercial operation deadline extension to continue Project development. Washtenaw asserts that, despite these delays, it is

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[7] *Id.* at 5-6.

[8] *Id.* (citing Mich. Pub. Act 233).

[9] *Id.* at 2, 7, 10.

[10] *Id.* at 6-8.

continuing to develop the Project in good faith and has taken steps to resolve the local permit challenges through the state permit process.

10. Second, Washtenaw argues that its waiver request is limited in scope because it seeks a 24-month extension of the commercial operation deadline milestone limited to one project.[11] Washtenaw also states that the requested waiver would not relieve it of any financial requirements. Washtenaw contends that the requested waiver is tailored to account for the impact of unanticipated permitting challenges and Michigan's late-stage change in law and the resulting delays on the Project's development schedule.

11. Third, Washtenaw contends that the requested waiver addresses a concrete problem because, absent waiver, MISO will terminate the Washtenaw GIA if the Project does not achieve commercial operation by December 31, 2026.[12] Washtenaw states that it is actively developing the Project but will not meet the current commercial operation deadline due to circumstances outside of its control. Washtenaw states that it anticipates receiving the necessary state permit by the third quarter of 2026, which could extend into 2027. Washtenaw contends that it will then take approximately 18 months to finish construction, project testing, and backfeed. Washtenaw asserts that the requested waiver will provide sufficient time for Washtenaw to secure a permit and complete construction of the Project without having the Washtenaw GIA terminated.

12. Finally, Washtenaw argues that the requested waiver will not have undesirable consequences, such as harming third parties.[13] Washtenaw states that it has fully securitized the network upgrades and commits to funding the assigned network upgrades on the originally contemplated timelines. Therefore, Washtenaw asserts that the waiver would not negatively impact other interconnection customers and would allow the Project to move forward without disrupting the interconnection queue.

13. Washtenaw states that it is authorized to represent that MISO supports and ITC Transmission does not oppose the waiver request.[14]

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[11] *Id.* at 8.

[12] *Id.* at 9.

[13] *Id.*

[14] *Id.* at 2.

III. Notice and Responsive Pleadings

14. Notice of Washtenaw's filing was published in the *Federal Register*, 90 Fed. Reg. 11537 (Mar. 7, 2025), with interventions and protests due on or before March 19, 2025. MISO filed a timely motion to intervene.

IV. Discussion

A. Procedural Matters

15. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2024), MISO's timely, unopposed motion to intervene serves to make it a party to this proceeding.

B. Substantive Matters

16. We grant Washtenaw's waiver request. Specifically, we grant Washtenaw's request for waiver of GIP section 4.4.4 and Article 2.3.1 of the Washtenaw GIA to allow a 24-month extension of the commercial operation deadline for the Project, from December 31, 2026 to December 31, 2028. The Commission has granted waiver of tariff provisions where: (1) the applicant acted in good faith; (2) the waiver is of limited scope; (3) the waiver addresses a concrete problem; and (4) the waiver does not have undesirable consequences, such as harming third parties.[15] We find that the circumstances of Washtenaw's waiver request satisfy these criteria.

17. First, we find that Washtenaw has acted in good faith to develop the Project in accordance with the GIP and the Washtenaw GIA. Washtenaw states that it has expended significant resources and effort developing the Project and ensuring that the Project remains viable, notwithstanding its challenges.[16] Washtenaw asserts that it has invested approximately $10 million to date to secure land, permits, design and engineering diligence, and long-lead equipment and has sought to mitigate delays and resolve the local setback ordinance issue so that the Project can move forward.[17]

18. Second, we find that the requested waiver is of limited scope because it represents a one-time waiver of GIP section 4.4.4 and Article 2.3.1 of the Washtenaw GIA to allow for a 24-month extension of the commercial operation deadline for the Project, from

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[15] *See, e.g.*, *Citizens Sunrise Transmission LLC*, 171 FERC ¶ 61,106, at P 10 (2020); *Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,059, at P 13 (2016).

[16] Waiver Request at 1-2, 7-8.

[17] *Id.*

December 31, 2026 to December 31, 2028. The limited waiver only applies to this deadline and does not relieve Washtenaw of any financial requirements in the Washtenaw GIA. Further, if the Project does not achieve commercial operation by December 31, 2028, the Washtenaw GIA will be subject to termination by MISO.

19. Third, we find that granting waiver will remedy a concrete problem. Absent waiver, MISO must terminate the Washtenaw GIA if the Project does not achieve commercial operation by the December 31, 2026 deadline. However, Washtenaw states that circumstances beyond its control have delayed the development of the Project such that it is unable to achieve commercial operation by December 31, 2026.[18] We find that granting waiver will provide Washtenaw the additional time needed to secure necessary permits, construct the Project, and achieve commercial operation by December 31, 2028.

20. Finally, we find that granting waiver will not have undesirable consequences, such as harming third parties. Washtenaw asserts that no other interconnection customers will be negatively affected by the extension of the Project's commercial operation deadline. In addition, Washtenaw commits to fund all required network upgrades on the originally contemplated timelines.[19]

The Commission orders:

Washtenaw's waiver request is hereby granted, as discussed in the body of this order.

By the Commission.

Debbie-Anne A. Reese,
Secretary.

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[18] *Id.* at 1.

[19] *Id.* at 9.

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