S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion, to implement the provisions of Sections 22 through 49 and related definitions of Public Act 235 of 2023.	Case No. U-21568

At the April 25, 2024 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Katherine L. Peretick, Commissioner
Hon. Alessandra R. Carreon, Commissioner

ORDER

On November 28, 2023, Governor Gretchen Whitmer signed into law Public Act 235 of 2023 (Act 235), which, among other things, amends Sections 22 through 49 of Public Act 342 of 2016 (Act 342) to increase the renewable portfolio standards (RPS) for electric providers from 15% through 2029, to 50% in years 2030 through 2034, and 60% in 2035, and thereafter. Act 235 took effect on February 27, 2024.

Section 22(3) of Act 235 requires electric providers to file with the Commission their respective amended renewable energy plans (REPs) within one year of the effective date of Act 235. For rate-regulated electric providers, the amended REP shall include a mechanism for recovering the incremental cost of compliance within their rates and a forecast of the renewable energy resources needed to comply with the new RPS set forth in Section 28(1). For rate-regulated electric providers, the Commission shall conduct a contested case pursuant to the

Administrative Procedures Act of 1969, MCL 24.201 *et seq*., and the Commission shall issue a final order in these matters approving the REP, approving the REP with changes consented to by the provider, or rejecting the REP within 300 days from the date of filing.

On February 8, 2024, the Commission issued an order in this docket (February 8 order) setting a staggered schedule for the amended REP filings pursuant to Section 22 of Act 235 with DTE Electric Company (DTE Electric) filing no later than July 19, 2024; Consumers Energy Company (Consumers) filing no later than November 15, 2024; Alpena Power Company (Alpena), Indiana Michigan Power Company (I&M), Northern States Power Company, Upper Michigan Energy Resources Corporation (UMERC), and Upper Peninsula Power Company filing their respective amended REPs no later than January 17, 2025; and cooperatives, municipally owned utilities, and alternative electric suppliers (AESs) filing no later than February 27, 2025. In the February 8 order, the Commission also sought comments on the following topics:

1. What, if any, changes are needed to the Michigan Renewable Energy Certification System [MIRECS] to facilitate compliance with Act 235?

2. What changes to utility procurement practices might be helpful in supporting the accelerated renewable energy development needed to comply with Act 235?

3. Currently, biomass facilities are allowed to perform a calculation in which the effective heat rates of the individual fuel stocks are compared to the total megawatt-hours of the facility to determine the percentage of renewable fuel. Do the changes in how biomass facilities are defined under Act 235, including the change to the definition of a renewable energy system under Section 11(j) of Act 235, require changes to this calculation? Are there other changes relating to the operation of biomass facilities, including the use of railroad ties as a renewable fuel feedstock, that are required as a result of the enactment of Act 235?

4. Section 49(1) of Act 235 states that an electric provider that has recorded a regulatory liability or asset on the incremental cost of compliance for the last 12 months shall be subject to a renewable energy cost reconciliation. If the electric provider utilizes a rate base cost recovery methodology for renewables to comply with Act 235, is this considered a cost of compliance?

5. With respect to electric providers that may not have a renewable portfolio requirement going forward subject to the nuclear provision in Section 28(3)(b) of Act 235, could any regulatory liability balance from compliance with Act 342 be considered something other than a regulatory liability as defined in Act 235? What other considerations should inform how the Commission addresses issues associated with existing regulatory liabilities associated with past RPS deployment?

6. As the amount of renewable energy on the power system increases, certain energy-related attributes may have greater value to the power system as a whole. Some, but not all, renewable energy resources can continue to offer these attributes, which include dispatchability, voltage support, and a hedge against disruptions or price increases in other generation inputs. Consistent with the continuing requirements under MCL 460.6t(8)(a), which require the Commission to consider diversity of generation supply when evaluating a utility's resource mix, what changes, if any, are necessary to appropriately value these attributes and characteristics?

7. Finally, the Commission invites additional comments on any other anticipated issues regarding the requirements of Sections 22 through 49 of Act 235 not specified above.

February 8 order, pp. 2-3. Comments were due no later than 5:00 p.m. (Eastern time (ET)) on March 8, 2024, and reply comments were due no later than 5:00 p.m. (ET) on March 22, 2024. *Id*., p. 3.

The Commission received comments from the Michigan Energy Innovation Business Council and Advanced Energy United (EIBC/United); UMERC; Michigan Environmental Council, Natural Resources Defense Council, Ecology Center, and Sierra Club (together, as MNSC); Consumers; Alpena; DTE Electric; I&M; Great Lakes Renewable Energy Association (GLREA); Wolverine Power Supply Cooperative, Inc.; Virtus Solis Technologies, Inc. (Virtus Solis); the Coalition for Community Solar Access (CCSA); Michigan Municipal Electric Association (MMEA); L'Anse Warden Electric Company (L'Anse Warden);[1] Michigan Biomass; Cloverland Electric

[1] L'Anse Warden filed its comments confidentially under seal. These comments, along with several others, are located within the docket's Case Comments section. *See*, Case No. U-21568, filings #U-21568-0001-CC through -0008-CC.

Cooperative (Cloverland); and Dillon Power, LLC (Dillon Power). Reply comments were filed by Michigan Biomass, I&M, GLREA, DTE Electric, Energy Michigan, Consumers, and EIBC/United.

These comments are available in the docket and therefore, for brevity purposes, this order summarizes them only briefly and addresses relevant issues therein. Dillon Power's comments were limited to its indication that it is no longer serving customer load and has no plans to do so by the February 2025 deadline for filing amended REPs. Dillon Power's comments, filing #U-21568-0002-CC.

1. What, if any, changes are needed to the Michigan Renewable Energy Certification System to facilitate compliance with Act 235?

DTE Electric and Consumers comment that changes to the Michigan Renewable Energy Certification System (MIRECS) system are unnecessary. DTE Electric's comments, filing #U-21568-0011; Consumers' comments, filing #U-21568-0008. I&M agree and added that to the extent emission free energy credits (EFECs) associated with nuclear generation are needed for future compliance, it will be necessary to ensure that MIRECS can support the transfer of EFECs from the PJM Interconnection, L.L.C. (PJM) Generation Attribute Tracking System (GATS). I&M's comments, filing #U-21568-0012. Michigan Biomass commented that MIRECS administrators should make the necessary changes with external input and modest adjustments, but that the current MIRECS process for prorating RECs for biomass facilities should remain. Michigan Biomass's comments, filing #U-21568-0003-CC. Cloverland comments that timestamped RECs must be created to be able to match renewable and clean energy generated to energy consumed. Cloverland suggests a mechanism to facilitate entering hourly load to match hourly RECs, enabling the RPS fulfillment process to be accomplished within MIRECS.

Cloverland lastly questions whether more compatible registries can be added such as adding PJM's GATS. Cloverland's comments, filing #U-21568-0004.

Alpena comments that while changes to MIRECS may not be necessary to comply with Act 235, RECs are obtained per Section 28(5)(b) of Act 235 by acquiring renewable energy and capacity which will require the accommodation of market purchases where the generation source of RECs, energy, and capacity could all be different systems. Alpena's comments, filing #U-21568-0009.

In their comments, MNSC notes that utilities must certify that they are acquiring and using both capacity and energy or just energy and that MIRECS must be updated to track the percentage of RECs that are unbundled and ensure that no utility has over 5% of its annual RECs from unbundled sources. Additionally, the system must ensure that the 5% unbundled RECs come from the territory of the regional transmission organization (RTO) to which a utility is a member. MNSC suggests that MIRECS should use the annual resource plans as the process for verifying that the utilities are using the capacity they are claiming and that MIRECS should require detailed reporting of the fuel type for all kilowatt-hours (kWh) certified. MNSC adds that the only locational requirement under Act 235 is for the unbundled RECs to ensure they come from within MISO or PJM. MNSC's comments, filing #U-21568-0007.

MMEA comments that MIRECS must incorporate functionality to import RECs from the MISO and PJM RTO footprints and streamline this import process to reduce delays on REC imports and develop functionality for aggregating accounts and retirements for joint action agencies to comply with Act 235. Also, the MIRECS sub-account view should be updated to allow all rows to be viewed on a single page to streamline REC transfer functionality. MMEA's comments, filing #U-21568-0005-CC. Wolverine suggests that the current MIRECS limits of

100 kilowatts (kW) for individual resources and 1 megawatt (MW) aggregations reduce efficiency and discourage registration. To accommodate anticipated growth of rooftop solar and other distributed energy resources (DERs), Wolverine proposes the minimum individual size for aggregation be increased to 550 kW, aligning with the latest distributed generation (DG) size limit, and a corresponding increase in the aggregated limit to 10 MW. Wolverine's comments, filing #U-21568-0015. Virtus Solis asks that explicit references to space-based solar power (SBSP) as a form of clean and renewable energy for Sections 3 and 11 of Act 235 be incorporated in rules adopted by the Commission. Virtus Solis asks the Commission to adopt several rules recognizing and qualifying SBSP for use in complying with Act 235. Virtus Solis's comments, filing #U-21568-0001-CC.

In response to Cloverland, I&M states that while the ability to time match RECs is important, it is not clear if Cloverland is suggesting that compliance with the RPS should be done on an hourly basis. Act 235 does not require this, and per I&M, consistent with current practices, RPS compliance should be done on an aggregate calendar year basis. Time matching renewable energy to load would require a significantly higher level of riskier investment and investment in technologies that are very early in the developmental phase. I&M replies that such resources present greater risks and uncertainty as to cost and viability that impact customer affordability, reliability, and resource adequacy. I&M's reply comments, filing #U-21568-0021. In its reply comments, GLREA agrees with MNSC that there are several changes to MIRECS are needed to implement Act 235, particularly the tracking of unbundled RECs. GLREA also supports Wolverine's recommendation that MIRECS support larger aggregations of small projects, such as rooftop solar, which will support utilities buying RECs from renewable energy system owners to meet RPS compliance at a lower cost. GLREA's reply comments, filing #U-21568-0020.

The Commission appreciates the commenters' insights on this issue. The Commission agrees that the locational requirement of RECs and the limitation on unbundled RECs required by Act 235 are additional measures that will need to be tracked in MIRECS to ensure compliance. However, the Commission is aware through communications between the Commission Staff (Staff) and the MIRECS administrators that MIRECS has already made and is prepared to make adjustments to its system to accommodate the changes in Act 235, namely tracking the unbundled RECs that make up the 5% limitation, the transfer of RECs from any certified RECs system within the MISO and PJM footprint, and reclassifying tire-derived fuel (TDF) as an ineligible fuel. Speaking to the need for timestamping within MIRECS, the Commission does not find that Act 235 requires certification and timestamping of RECs more frequently than is currently necessary for certifying on-peak and off-peak incentive RECs. The Commission also notes that a renewable energy resource and clean energy system are defined by statute, and the Commission does not see the need to clarify these defined terms further at this time.

2. What changes to utility procurement practices might be helpful in supporting the accelerated renewable energy development needed to comply with Act 235?

As a provider with no generation assets that purchases energy, capacity, and RECs obtained through competitively bid contractual agreements, Alpena asks the Commission to consider an expedited timeline for regulatory review and approval to reduce uncertainty following contract execution, leading to a more competitive cost for customers. Alpena's comments, filing #U-21568-0009. Cloverland comments that, if procurement means how a utility plans energy resource building or purchases through power purchase agreements (PPAs), the Commission should create a review board to quickly answer questions related to those resources and PPAs and whether they meet the requirements of Act 235. Cloverland's comments, filing #U-21568-0004. Consumers comments that the option to procure resources without the use of the competitive procurement process in certain situations will remain needed and be beneficial to renewables development. Also, Consumers states that it sees value in continuing to have the option to deviate from the target amounts of capacity identified in an annual solicitation. Consumers' comments, filing #U-21568-0008.

DTE Electric made three statements on the procurement topic, namely that: (1) utilities should continue to follow the Commission's Competitive Procurement Guidelines for Rate-Regulated Electric Utilities (Not for Public Utility Regulatory Policies Act (PURPA) Compliance) (competitive procurement guidelines); (2) contract approval filings with contracts consistent with a Commission-approved REP should continue to be heard *ex parte*, allowing for expedited approvals; and (3) an amended REP should allow flexibility in build plans to either accelerate capacity deployment or adjust capacity allocation depending on results of the competitive bidding process. DTE Electric contends that flexibility to allocate capacity between the company's traditional REP and the company's voluntary green pricing (VGP) program as well as between third-party and company-owned projects is critical in allowing the company to meet its commitments. DTE Electric's comments, filing #U-21568-0011. I&M asks that the Commission consider the following as a means to streamline the procurement review and approval process: (1) support acquisition outside the formal request for proposals (RFP) process to expand resource opportunities and flexibility, (2) support an expedited timeline for regulatory review and approval, (3) support pre-approval of reasonable risk contingency, (4) provide for special consideration of the utility's re-use of existing interconnections and capacity injection rights outside of a formal RFP process, and (5) ensure contract pricing and terms are not shared publicly. I&M's comments, filing #U-21568-0012.

GLREA comments that changes to the procurement processes should achieve the following: (1) more viable PURPA standard contract terms to minimize transaction costs and streamline contract negotiation and to utilize a 50/50 mix of utility-owned projects and PPAs; (2) complete cost estimates when seeking project approval of proposed projects, particularly for build-transfer agreements (BTAs) to include property procurement or leasing, engineering and decommissioning costs, or overhead and profit; (3) a level playing field when comparing smaller sites for DG procurement by means of higher DG compensation in recognition of its benefits; (4) higher and defined compensation for dispatchable generation projects with storage; and (5) better-quality solar panels purchased. GLREA's comments, filing #U-21568-0013. MNSC asks that the Commission strengthen the competitive procurement guidelines established in Case No. U-20852 and adopt transparent procurement practices. MNSC contends that independence of the procurement process from utility companies is paramount and that the Commission should reconsider requiring utilities to utilize an independent administrator (IA) for procurements in which the utility participates as a bidder. MNSC's comments, filing #U-21568-0007. EIBC/United comments that the Commission should require an IA in competitive procurements, that utilities should not be permitted to own all assets, and that the Commission should establish a community solar program with on-bill credits. EIBC/United's comments, filing #U-21568-0005. UMERC asks the Commission for flexibility in procurement in light of the need for an increase in renewable projects required for Act 235 compliance. UMERC's comments, filing #U-21568-0006.

Energy Michigan replied to Alpena, stating that AESs are similarly situated to Alpena in that many do not have generation within the state and currently purchase unbundled RECs for compliance. Energy Michigan asks the Commission to clarify any penalties and a cure period for compliance and for guidance on market-based contracts for compliance. Energy Michigan's comments, filing #U-21568-0018. In reply comments, Consumers responded to GLREA's statements regarding PURPA and contends that PURPA projects are not always less costly and that adding storage may not provide additional value. Responding to EIBC/United, Consumers states that a PPA is not always the least cost option and that third-party community solar is not economically better than utility-owned community solar or utility scale solar. Consumers' reply comments, filing #U-21568-0017.

GLREA agrees with MNSC that the competitive procurement guidelines should be revisited and strengthened but disagrees with I&M's and Consumers' request for consideration of procured projects outside of the RFP process. GLREA's reply comments, filing #U-21568-0020. EIBC/United similarly oppose the suggestion that resource procurement could be done outside of an RFP. EIBC/United's reply comments, filing #U-21568-0016. Michigan Biomass agrees with some comments that procurement may take place outside of the IRP process but states that unsolicited procurements should not become the standard. Michigan Biomass's reply comments, filing #U-21568-0008-CC.

In its reply comments, I&M responded to EIBC/United contending that they misunderstand the role of an independent monitor (IM) and maintaining the need to consider procurement outside of an RFP. In response to GLREA's calls for a 50/50 mix between utility-owned projects and PPAs, I&M states that for utilities with smaller footprints, such an arrangement would increase costs for utilities with smaller footprints. I&M's reply comments, filing #U-21568-0021.

The Commission thanks the commenters for their insights regarding potential changes to procurement practices that may be needed as Act 235 is implemented. The Commission notes the calls for flexibility in resource acquisition and expedited reviews. The Commission points out that

Act 235 (as did the previous statute, Act 342) allows the Commission to consider and approve contracts based on unsolicited proposals in certain circumstances, and so, the Commission does not foreclose the consideration of procurement outside of the RFP process. However, the Commission emphasizes that resource procurement must also be considered in the context of IRPs, as discussed below, and consistency between approved IRPs and REPs must be achieved. Further, Act 235 contemplates flexibility in Section 32 by allowing extensions for good cause. *See*, MCL 460.1032.

As to the competitive procurement guidelines, an extensive collaborative process went into the development and finalizing of these guidelines and the Commission does not find it advisable to re-open a proceeding to revise the guidelines at this time. The current guidelines allow for the use of an IM or an IA, as called for in some comments. However, as acknowledged in the development of the guidelines and order approving the guidelines, the guidelines were intended to be improved upon and revised periodically. Therefore, while declining to immediately open a proceeding to do so, the Commission does not foreclose their revision in the future.

Lastly, of note, Public Act 295 of 2008 (Act 295) contained the 50/50 utility ownership versus a PPA split requirement. Act 342, which amended Act 295, removed this requirement and Act 235 similarly omits this requirement. Therefore, the Commission shall continue to address ownership allocation through contested proceedings.

3. Currently, biomass facilities are allowed to perform a calculation in which the effective heat rates of the individual fuel stocks are compared to the total megawatt-hours of the facility to determine the percentage of renewable fuel. Do the changes in how biomass facilities are defined under Act 235, including the change to the definition of a renewable energy system under Section 11(j) of Act 235, require changes to this calculation? Are there other changes relating to the operation of biomass facilities, including the use of railroad ties as a renewable fuel feedstock, that are required as a result of the enactment of Act 235?

Consumers cites the change in Act 235 that excludes facilities that co-fire biomass with tires or TDF as renewable energy systems as that impacted the utility but states that no changes are necessary in the calculation to determine the percentage of renewable fuel. Consumers' comments, filing #U-21568-0008. Michigan Biomass commented that there should be a continued use of the heat rate calculation for co-firing with affidavits. Michigan Biomass asks the Commission to clarify Section 11(j) in Act 235, which states that a renewable energy system excludes facilities that co-fire biomass with tires or TDF but gives no instruction on how a biomass facility would establish itself as a renewable energy system when starting or ceasing co-firing with tires or TDF. Michigan Biomass also asked for clarity on the meaning of legacy facilities under Section 11 of Act 235 defining biomass facilities as renewable energy systems if in commercial operation on the effective date of the Act. Michigan Biomass's comments, filing #U-21568-0003-CC. MNSC comments that the heat rate calculation must be updated to exclude plastics, post-use polymers, and industrial waste for RECs for new biomass facilities. MNSC's comments, filing #U-21568-0007.

EIBC/United responded to MNSC stating that post-use polymers and industrial waste are not currently considered for RECs on the co-firing calculation, so MNSC's concern is moot. EIBC/United's reply comments, filing #U-21568-0016.

The Commission finds that the calculation of the effective heat rates for individual fuel stocks performed to determine the renewable fuel percentage does not require changes at this time and that special consideration for railroad ties as a renewable fuel stock is similarly not required at this time. With respect to biomass facilities, the Commission recognizes the changes made by the Legislature in Act 235 in terms of the definitions of renewable energy resources and renewable energy systems, namely, the exclusion of TDF as a qualifying renewable energy fuel for Act 235 compliance. *See*, MCL 460.1011(g) and (i). As a creature of statute, the Commission is tasked with carrying out the letter of the law and the Legislature's intent regarding the role of biomass facilities under Act 235. Consistent with the statute, the Commission finds that a biomass facility's qualification as a renewable energy system will depend on the derivation of its fuel mix at any given time. Understanding that a biomass facility may co-fire different fuel sources at different times, the tracking and heat rate calculation of these fuel sources is imperative to determinations of eligibility as a renewable energy system.

Specifically, while it seems clear that Section 11(j)(v) of Act 235 precludes a biomass facility from qualifying as a renewable energy system while co-firing biomass with tires or TDF, it also seems clear that the Legislature did not intend for a biomass facility that had ever co-fired biomass with TDF to be permanently disqualified from qualifying as a renewable energy system. Indeed, such an interpretation would be at odds with the reality that several existing biomass facilities have co-fired biomass with TDF since the enactment of Act 295. Rather, it seems that the Legislature intended the eligibility of a biomass facility as a renewable energy system to be tied to the fuel mix used to generate electricity at a particular time; when the fuel mix includes co-firing biomass with TDF, the facility does not qualify as a renewable energy system, but the same facility can again qualify as a renewable energy system when not co-firing biomass with TDF (subject to the proration with other non-renewable fuels as discussed above).

The Commission adds that the individual amended REP proceedings for electric providers relying on biomass facilities will serve as the best venue in which to address compliance and renewable energy resource eligibility issues.

4. Section 49(1) of Act 235 states that an electric provider that has recorded a regulatory liability or asset on the incremental cost of compliance for the last 12 months shall be subject to a renewable energy cost reconciliation. If the electric provider utilizes a rate base cost recovery methodology for renewables to comply with Act 235, is this considered a cost of compliance?

Alpena comments that electric providers should be permitted to transition costs to base rates in future proceedings. Alpena's comments, filing #U-21568-0009. Consumers comments that a regulatory asset or regulatory liability must be reflected in rate base for cost recovery. Consumers' comments, filing #U-21568-0008. In its comments, DTE Electric states that a regulatory asset or regulatory liability should be considered a cost of compliance even if recovered through base rates as Sections 47(2) and (3) of Act 235 do not exclude such mechanisms. DTE Electric's comments, filing #U-21568-0011. I&M states that the Commission should maintain the regulatory asset and regulatory liability treatment utilizing a rider for flexibility but allow for the conversion to base rates. I&M's comments, filing #U-21568-0012.

GLREA recommends that the Commission should reconcile approved regulatory assets or liabilities in accordance with Section 49(1) and exclude costs if a utility's performance does not meet expectations. GLREA's comments, filing #U-21568-0013. MNSC contends that providers should be subject to renewable reconciliations regardless of the incremental cost of compliance recovery method. MNSC's comments, filing #U-21568-0007.

In its reply comments, DTE Electric responds to GLREA that the performance of assets can be impacted by many factors outside of the utility's control and thus, disagrees with GLREA's suggested cost disallowance. DTE Electric's reply comments, filing #U-21568-0019. I&M

disagrees with GLREA that costs approved in rate base should then be reviewed in renewable reconciliations because it would be duplicative. I&M's reply comments, filing #U-21568-0021.

The Commission appreciates the commenters' insights into this issue pertaining to cost recovery. As discussed in the comments, Act 235 allows for recovery mechanisms in base rates or as a regulatory liability or regulatory asset with annual reconciliations. The Commission finds that the requirements of Act 235 are likely to produce the same need for rate-regulated utilities to record regulatory assets and liabilities subject to contested reconciliation proceedings.

5. With respect to electric providers that may not have a renewable portfolio requirement going forward subject to the nuclear provision in Section 28(3)(b) of Act 235, could any regulatory liability balance from compliance with Act 342 be considered something other than a regulatory liability as defined in Act 235? What other considerations should inform how the Commission addresses issues associated with existing regulatory liabilities associated with past RPS deployment?

In DTE Electric's comments, it supports the continuation of the incremental cost of compliance regulatory liability reserve fund combined with the transfer price. DTE Electric's comments, filing #U-21568-0011. I&M states that the existing regulatory liability balances can be maintained and used to offset future costs of compliance with the increasing renewable standards under Act 235. I&M's comments, filing #U-21568-0012. MNSC comments that any regulatory balance from Act 342 should continue to be a regulatory balance under Act 235 and that renewable reconciliations should be filed accordingly. MNSC's comments, filing #U-21568-0007. UMERC supports clearing regulatory balances from prior RPS requirements. UMERC's comments, filing #U-21568-0006.

In reply comments, I&M agrees with MNSC that regulatory liability balances should be maintained to mitigate rate volatility. I&M's reply comments, filing #U-21568-0021.

The Commission agrees that any regulatory liability balances should continue forward and be addressed in renewable reconciliation proceedings as is the current practice.

6. As the amount of renewable energy on the power system increases, certain energy-related attributes may have greater value to the power system as a whole. Some, but not all, renewable energy resources can continue to offer these attributes, which include dispatchability, voltage support, and a hedge against disruptions or price increases in other generation inputs. Consistent with the continuing requirements under MCL 460.6t(8)(a), which require the Commission to consider diversity of generation supply when evaluating a utility's resource mix, what changes, if any, are necessary to appropriately value these attributes and characteristics?

In its comments, Alpena expresses concern that it has far fewer opportunities for renewable energy resource acquisition than larger suppliers and will be subject to much higher pricing in resource procurement. Additionally, Alpena suggests that small power producers should be compensated for ancillary benefits. Alpena's comments, filing #U-21568-0009. CCSA encourages the Commission to use a data-driven technology-neutral analysis that should incorporate both generation and transmission and distribution benefits and understand both the present and future value of distributed community solar in its implementation of Sections 22 through 49 of Act 235. CCSA asserts that generation benefits should include the value of avoided energy, avoided generation capacity, avoided ancillary services, avoided line losses, hedging/wholesale risk premium, and wholesale market price suppression benefits through Demand Reduction Induced Price Effect Benefits. CCSA also states that distribution benefits should include avoided transmission charges, avoided transmission capacity costs, and avoided distribution capacity costs. CCSA's comments, filing #U-21568-0006-CC. Cloverland contends that base-load assets, off-peak assets, and assets that are subject to regulation as defined by regulatory agencies such as MISO should be valued higher than intermittent assets, by offering more renewable energy attributes for the purpose of compliance with both the renewable and clean energy standards. Cloverland's comments, filing #U-21568-0004.

Consumers comments that this question should be addressed in discussions involving IRPs and MCL 460.6t because an IRP, and its associated process, provide a more wholistic evaluation of a utility's supply portfolio and take into consideration the different aspects of value related to diversity. Consumers' comments, filing #U-21568-0008. DTE Electric states a similar position in its comments advising that IRPs are the appropriate venue for considering resource diversity, not REPs. DTE Electric's comments, filing #U-21568-0011. I&M comments that when evaluating renewable resources relative to diversity of generation supply, the amount and diversity of generators a utility will have as part of its total portfolio needs to be considered, along with the flexibility of the generation supply. From an operational reliability perspective, when considering renewable resources as part of a utility's portfolio of generation resources, I&M contends that a wide array of coordinated decisions between the utility, RTOs, and the Commission is needed to support operational flexibility. I&M states that the Commission should work with the RTOs to ensure that their market rules and designs continue to evolve in a way that favors the needed attributes and sends appropriate price signals in support of these attributes; I&M also states that the Commission should limit its consideration to observable system costs (incurred or avoided). I&M's comments, filing #U-21568-0012. Similarly, Michigan Biomass states that the Commission should quantify attributes like fuel diversity, volts-amp reactive and voltage support, line loss mitigation, and baseload generation in IRPs. Michigan Biomass's comments, filing #U-21568-0003-CC.

GLREA addresses this question as it relates to capacity and pricing, demand response (DR), fuel-price hedging, voltage and frequency regulation, grid resilience, and generation input prices. Broadly, GLREA suggests that critical peak pricing and valuing generation should match as the transition from traditional base-load generation resources continues. GLREA contends that

Michigan will require more DR, such as electric vehicles or on-site storage, to reduce peak load and that renewable generation acts as a fuel price hedge that should be valued. GLREA further comments that generation co-located with load would help avoid outages, that battery-inverter systems can provide black start, and that compensation for such resources should reflect this ability. GLREA's comments, filing #U-21568-0013. Per MNSC, renewables have energy-related attributes that provide value to the power system and should therefore be considered within IRPs. However, MNSC believe that before undertaking changes to how the Commission evaluates a utility's resource mix, these energy-related attributes must be fully valued. MNSC recommends that the Commission undertake these valuation analyses and integrate the findings into the IRP process. MNSC's comments, filing #U-21568-0007. EIBC/United also recommended a value of storage analysis, including behind the meter storage. EIBC/United's comments, filing #U-21568-0005.

MMEA comments that the referenced attributes in the Commission's question are wholesale market products, and therefore, these attributes should be addressed within the MISO and PJM tariffs. Also, MMEA states that advocacy for these attributes should take place through the RTO participant processes. MMEA's comments, filing #U-21568-0005-CC. UMERC comments that the value of all generation resources, including those procured or constructed to meet the enhanced RPS requirements included in Act 235, should reflect all value streams, including those set by MISO. UMERC contends that the complete value of a resource to its customers should be included in the evaluation of resource selection, procurement, construction and deployment to meet the RPS compliance requirements set forth in Act 235. UMERC's comments, filing #U-21568-0006. Virtus Solis's comments focus on the attributes of SBSP as a dispatchable, firm, always-on resource that can be installed with limited land use and will lower costs associated with over-building local grids and unnecessary storage and transmission. Virtus Solis's comments, filing #U-21568-0001-CC.

Responding to MNSC, GLREA, and EIBC/United, DTE Electric maintains that resource diversity is best addressed in IRPs. DTE Electric's reply comments, filing #U-21568-0019. I&M replies that coordination with RTOs is needed as transmission attribute considerations are an important factor. Responding to MNSC, I&M states that energy and capacity are important values in planning, adding that as more renewables are included in resource portfolios, coordination with transmission owners becomes increasingly important. I&M's reply comments, filing #U-21568-0012. In its reply comments, GLREA disagrees with Consumers that certain attributes need to be defined by MISO or PJM, stating that the Commission can determine these. GLREA then reiterates that generation co-location can improve reliability. Lastly, responding to the investor-owned utilities (IOUs), GLREA argues that combined portfolio attributes need to be considered to evaluate diversity. GLREA's reply comments, filing #U-21568-0013. Michigan Biomass agrees with DTE Electric and Consumers regarding the importance of resource diversity and agrees with Alpena that small power producers should be compensated for ancillary benefits. However, Michigan Biomass disagrees with MNSC that ancillary valuation be limited to non-emitting resources. Michigan Biomass's reply comments, filing #U-21568-0008-CC.

The Commission agrees with several comments 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 (including the consideration of the value of the various resource types and attributes as expressed by commenters). In turn, future amended REPs should reflect the assumptions included in the providers' most recently approved IRP; however, the initial amended REP filed pursuant to the schedule set in this docket may not align with the most recently approved IRP. The Commission recognizes that for the initial round of amended REPs pursuant to Act 235, the most recently approved IRP may not reflect the renewable energy build out necessary under Act 235. Therefore, the initially filed amended REP should reflect the utility's plans to comply with Act 235. Conversely, a future IRP should also reflect the providers' approved amended REP. Further, if decisions made in IRPs necessitate a change to the provider's REP, the provider shall then be required to file within six months an amended REP consistent with the approved IRP.

The Commission also agrees with I&M, Cloverland, and MMEA that many of the attributes identified are indeed wholesale market products and that coordination with the RTOs is necessary to ensure that the RTO market rules send appropriate price signals to support the attributes that contribute to operational flexibility. The Commission will continue to encourage reforms to RTO market design to appropriately value these attributes as the power sector continues to evolve even as it considers a broad array of resources to promote generation diversity in individual IRPs.

7. Additional comments on any other anticipated issues regarding the requirements of Sections 22 through 49 of Act 235 not specified above.

Alpena requests Commission guidance on market-based contracts to procure long-term resources avoiding duplicative energy and capacity purchases. Alpena's comments, filing #U-21568-0009. Cloverland asks for: (1) clarity on the compliance period and penalties for non-compliance with Act 235, (2) clarity on the 5% limit on unbundled RECs to meet Act 235 compliance in terms of whether the cap applies to RECs generated in prior years and whether the exemption for municipalities but not electric cooperatives was intentional, (3) clarity on various aspects of the limits and requirements for RECs under Act 235, (4) the reason electric cooperatives and municipalities were excluded from the Upper Peninsula legislative study, (5) clarity as to whether the storage requirement applies to electric cooperatives and municipalities, and (6) clarity on whether behind-the-meter generation reduces the annual retail sales used to calculate the RPS requirement. Cloverland's comments, filing #U-21568-0004.

Consumers comments that the unpredictability issue of commercial operation dates for renewable projects remains largely due to local permitting processes, which is expected to be improved with the enactment of Public Act 233 of 2023 granting the Commission siting authority. Consumers adds that another issue that remains an open risk for adding renewable resources in a timeframe that is compliant with Act 235 is the continued uncertainty of the MISO generator interconnection queue. Consumers states that it is anticipated that the 2024 queue will open in the second half of 2024; however, the exact schedule is unknown at this time. Consumers explains that the impact of the approved queue reforms on interconnection timelines is yet to be seen. Consumers' comments, filing #U-21568-0008. Also commenting on the MISO interconnection queue, DTE Electric states that ongoing policy evaluations by both the Federal Energy Regulatory Commission and MISO, including reforms to the MISO interconnection queue, assessment of reliability attributes, and resource accreditation changes, hold potentially significant implications for planning processes in the coming years. DTE Electric contends that it is critical that there is adequate consideration of potential impacts of policy proposals on planning, development, and costs as providers file and implement amended REPs. DTE Electric's comments, filing #U-21568-0011.

GLREA's comments covered several topics, namely that: (1) DG compensation should include grid service costs, (2) real time DER utilization and compensation should be employed, (3) energy-to-home and energy-to-grid need to be developed with appropriate compensation rates, (4) behind-the-meter DR approaches must be developed, and (5) non-wires alternatives (NWAs) need to be expanded. GLREA's comments, filing #U-21568-0013. In its comments, MNSC noted that Act 235 requires that VGP programs cannot result in increased costs for non-participating customers. The new renewable energy standards will drive significant renewable energy development, including in VGP programs. MNSC states that the Commission must monitor how renewable projects costs are assigned across these two programs to ensure that utilities allocate the cheaper projects for general service and the most expensive for VGP, as MNSC believes is required by Act 235. MNSC's comments, filing #U-21568-0007. Virtus Solar touts the virtues of SBSP as a viable energy solution in the face of climate change and its affordability as baseload energy priced at $30 per megawatt. Virtus Solis's comments, filing #U-21568-0001-CC.

In reply comments, Energy Michigan requests that the Commission allow interested persons the opportunity to review and comment on the proposed REP filing requirements before they are finalized so that filers have sufficient notice of the requirements pertaining to the filing. In terms of Act 235 implementation, Energy Michigan further states that it would help if the Commission: (1) provides guidance on allowing market-based contracts for RECs that will continue to enable smaller providers to maximize long-term procurement options and avoid costly and duplicative purchases for energy and capacity, (2) clarifies what the penalty structure and potential cure period would be for any provider that fails to meet their RPS requirements, and (3) finalizes the new REP filing requirements in a timely manner after allowing all interested parties an opportunity to comment on the revised REP filing requirements before enactment. Energy Michigan's comments, filing #U-21568-0018.

In its reply comments, DTE Electric agrees with Consumers' comments regarding the MISO interconnection queue. DTE Electric disagrees, however, with GLREA and MNSC, stating that DG issues are beyond the scope of this docket and that resources should be allocated equally among RPS and VGP portfolios. DTE Electric's reply comments, filing #U-21568-0019. I&M

also replied to GLREA's comments, stating that any perceived savings from DG requirements, decreasing loads, or by forestalling necessary upgrades are site-specific, subject to numerous factors, and would need to be identified and analyzed by the utility before being assumed to exist and quantified. I&M restates that utility rates are cost-based and not based on any externalities and that there are implementation challenges and costs associated with a real-time pricing system and compensation model. If implemented, I&M argues that DG customers should be responsible for these costs through a rider or tracking mechanism that ensures the utility can recover these costs from DG customers and not be at risk of loss if the number of DG customers or load and excess energy characteristics of DG customers changes in the future. I&M's reply comments, filing #U-21568-0021. GLREA also filed reply comments noting that related comment dockets and litigation in upcoming contested cases may raise additional issues related to this question. GLREA's comments, filing #U-21568-0013.

Again, the Commission notes its appreciation for the participation in this docket and the responsiveness to the issues raised. While this process is helpful to the Commission in its implementation of Act 235 moving forward, the Commission notes that specific action related to the amended REPs, the circumstances of each electric provider, and determinations on resources portfolios will be reserved for the appropriate contested proceeding. Further, issues related to DG and DER compensation, DR, and NWAs are beyond the scope of this proceeding and are being considered in other dockets.

Speaking to the specific issues raised here, the Commission first notes that Section 22 of Act 235 requires electric providers to file their amended REPs within one year of after the effective date of Act 235 and within two years after the Commission has issued an order approving the provider's last amended REP. The Commission then must issue a final order on the provider's amended REP within 300 days. Thus, the compliance period will be specific to each provider and will begin at the time the amended REP is approved. Turning to the request for clarification regarding potential penalties or a cure period, the Commission relies on its authority granted by the Legislature to administer Act 235 as well as its enforcement authority available under MCL 460.558 in ensuring that providers comply with Act 235. Violations of the Act will be addressed on an individual basis as needed in the appropriate proceeding.

Speaking to the 5% limit on unbundled RECs, the Commission understands there is concern from some providers that this limitation creates a burden for smaller providers who rely on REC purchases to meet RPS compliance. However, the 5% limit is a statutory requirement. *See*, MCL 460.1028(5)(c). The Commission, as a creature of statute, is not authorized to alter such a legislative directive. The Commission will, however, employ its tool of statutory interpretation in each electric providers' amended REP proceeding and will utilize the flexibility included in Act 235 when justified by the circumstances of the provider.

Turning to MNSC's comments regarding the allocation of assets between a utility's VGP program and its REP portfolio, the Commission agrees that more expensive assets should be allocated to VGP programs while less expensive assets should always be reserved for RPS compliance. As stated in the January 18, 2024 order in Case No. U-21361 (January 18 order), the Commission has acknowledged and continues to support electric providers' consideration of applying lower cost projects to RPS and IRP compliance as the cost for those projects is borne by all customers as opposed to VGP customers only who take on those program costs voluntarily. *See*, January 18 order, p. 3. The Commission encourages DTE Electric to continue its collaboration with the Staff in the selection of projects between the programs.

Lastly, with respect to the amended REP filing requirements, the Commission agrees that comment on the proposed amended REP filing requirements is advisable prior to the scheduled deadlines for the Act 235 amended REPs. Therefore, the Commission invites comment from interested persons on the draft amended REP filing requirements attached to this order as Exhibit A. The Commission will accept comments on these draft filing requirements until 5:00 p.m. (ET) on May 10, 2024. Written comments should be mailed to: Executive Secretary, Michigan Public Service Commission, P.O. Box 30221, Lansing, Michigan 48909. Comments submitted in electronic format may be filed via the Commission's E-Dockets website, or for those persons without an E-Dockets account, via e-mail to mpscedockets@michigan.gov. Any person requiring assistance prior to filing comments may contact the Staff at (517) 241-6180. All comments should be paginated and reference the above-captioned case, Case No. U-21568. All filed comments will become public information available on the Commission's E-dockets website either under the Filings or Case Comments section and will be subject to disclosure.

With respect to the upcoming amended REP filings, AESs that are no longer serving customers in Michigan will not be required to file an amended REP upon a filing with the Commission indicating the cessation of service with a supporting affidavit.

THEREFORE, IT IS ORDERED that interested persons may file comments on the draft amended renewable energy plan filing requirements attached to this order as Exhibit A. Comments must be filed no later than 5:00 p.m. (Eastern time) on May 10, 2024.

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 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

Katherine L. Peretick, Commissioner

Alessandra R. Carreon, Commissioner

By its action of April 25, 2024.

Lisa Felice, Executive Secretary

Michigan Public Service Commission
2023 Public Act 235

Filing Requirements and Instructions for Renewable Energy Plans for Michigan Investor-Owned Retail Rate-Regulated Electric Utilities

PA 235 of 2023 Section 22 *Within 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 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.*

PA 235 of 2023 Section 28 (1) *An electric provider shall achieve a renewable energy credit portfolio of at least the following:*

(a) Through 2029, 15%.
(b) In 2030 through 2034, 50%.
(c) In 2035 and each year thereafter, 60%.

(2) An electric provider's renewable energy credit portfolio shall be calculated as follows:

(a) Determine the number of renewable energy credits used to comply with this subpart during the applicable year.

(b) Divide by 1 of the following at the option of the electric provider as specified in its renewable energy plan:

(i) The number of weather normalized megawatt hours of electricity sold by the electric provider during the previous year to retail customers in this state, less the amount of sales attributable to customers participating in an electric provider's voluntary green pricing program under section 61 and the outflow from customers participating in the distributed generation program under section 173 for that year.

(ii) The average number of megawatt hours 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 program under section 61 and the outflow from customers participating in the distributed generation program under section 173 for that year.

(c) Multiply the quotient under subdivision (b) by 100.

(3) Notwithstanding subsection (1) and subject to subsection (4), in any year a cooperative electric provider or a multistate electric provider may calculate its maximum renewable energy credit portfolio requirement as follows:

(a) Determine the number of megawatt hours of electricity sold by the electric provider to retail customers in this state using the option the electric provider selected under subsection (2)(b).

(b) Subtract the number of megawatt hours of nuclear energy that the electric provider obtained from a system located in this state that the electric provider owned or from which the electric provider had contracted to receive nuclear energy on or before January 1, 2024.

(4) An electric provider described in subsection (3) is required to achieve a renewable energy credit portfolio equal only to the electric provider's maximum renewable energy credit portfolio requirement if the electric provider's maximum renewable energy credit portfolio requirement is less than the number of renewable energy credits required to comply with the applicable standard in subsection (1). If the electric provider is a multistate electric provider, and the electric provider's maximum renewable energy credit portfolio requirement is less than the number of renewable energy credits required to comply with the applicable standard in subsection (1), then the electric provider is required to achieve a renewable energy credit portfolio equal only to the electric provider's maximum renewable energy credit portfolio requirement if all of the following requirements are met:

(a) The electric provider's electricity generation systems located within this state produce energy exceeding the electric provider's electricity sales in this state.

(b) All of the electric provider's electricity generation systems located within this state are clean energy systems.

(c) All of the renewable energy credits generated in this state are used by the electric provider toward compliance with the renewable energy credit portfolio as calculated under subsection (2).

(d) Renewable energy and clean energy generated in this state equal to or exceeding the provider's electricity sales in this state are not used by the provider or any other provider to comply with any similar standards.

(5) Each electric provider shall meet the renewable energy credit standard, subject to subsection (3), with renewable energy credits 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.

PA 235 of 2023 Section 45 (1) *For an electric provider whose rates are regulated by the commission, the commission shall determine a revenue recovery mechanism, subject to section 47, for the electric provider's tariffs that permit recovery of the incremental cost of compliance to implement the amended renewable energy plan.*

(2) An electric provider's incremental cost of compliance shall be recovered through a revenue recovery mechanism that is designed consistent with the production allocation approved in the provider's most recent general rate case under section 6a of 1939 PA 3, MCL 460.6a. An electric provider may propose a revenue recovery mechanism in an amended renewable energy plan to include all or a portion of the electric provider's incremental cost of compliance in base

rates. If an electric provider proposes to include all or a portion of the incremental cost of compliance in base rates, the commission shall review and approve, approve with modifications, or deny the revenue recovery mechanism proposed by the electric provider.

(3) The incremental cost of compliance shall be calculated for a 20-year period beginning with approval of the amended renewable energy plan and may be recovered on a levelized basis.

The following suggests several elements that address the specific items to be included in the amended plan filings. These elements are based on current rate case standard filing requirements, PSCR filing requirements as well as RPS filing requirements of other utilities across the country. These suggestions are intended to be used only as initial guidance. They are not necessarily exhaustive. For any sections that are not applicable, please state as such.

1. Detailed renewable resource plan.

a) Forecast expected compliance levels by year to meet the renewable portfolio targets.
b) Identify key assumptions used in developing these forecasts and the proposed resource portfolio.
c) Identify risks which may drive performance to vary.

2. Sales forecast through 2045 for compliance with the renewable energy standard in PA 235 Section 28.

a) Specify whether megawatt hours of electricity used in the calculation is weather-normalized or based on the average number of megawatt hours of electricity sold by the electric provider annually during the previous 3 years to full-service retail customers in the state.

3.) Forecasted megawatt hour outflow from distributed generation customers through 2045.

a) Specify if renewable energy credits from distributed generation outflow are utilized towards compliance with the standard.

4. Forecasted megawatt hours attributable to the voluntary green pricing program through 2045.

5. Forecasted megawatt hours from nuclear energy for electric providers subject to PA 235 Sections (3) and (4) through 2045.

a) Include the energy system type of each electric generating system within the state.

b) Confirm that all renewable energy credits generated within the state are used to comply with the portfolio standard.

6. Forecast of meters by customer class through the end of the plan period if a monthly per meter surcharge is being utilized for recovery of the incremental cost of compliance.

7. Quantity of renewable energy credits

a) Outline the quantity of renewable energy credits the Company forecasts it must obtain each year to meet the renewable standard (PA 235 of 2023 Section 28(1)).
b) Forecast of renewable energy credits subject to the 5% limit as defined by PA 235 Section 28(5)(c) through 2035.
c) Forecast of energy waste reduction credits substituted in each year.
d) Describe the Company's planned renewable portfolio forecasted renewable energy credits obtained via the Michigan incentive renewable energy credits as provided for in PA 235 of 2023 Section 39

8. "Transfer Price" forecast

a) Forecast a price per MWh for each year of the remaining plan period ending in 2045 for renewable sold to full service retail customers, which will be used in calculating net incremental cost. (PA 235 Section 47)

9. Revenue requirement and cost recovery mechanism

a) Explain in detail the method to recover incremental cost of compliance.
b) Forecast incremental cost of compliance through the end of the plan period in 2045.
c) If applicable, forecast through the end of the plan period in 2045, the regulatory asset/liability balance.
d) Include the forecasted incremental cost of compliance over the plan period. Per (PA 342 of 2016 Section 47) Incremental costs of compliance shall be calculated to include the following:

- Capital, operating, and maintenance costs of renewable energy systems, including property taxes, insurance, and return on equity associated with an electric provider's renewable energy systems, including the electric provider's renewable energy portfolio established to achieve compliance with the renewable energy standards and any additional renewable energy systems that are built or acquired by the electric provider to maintain compliance with the renewable energy standards.

- Financing costs attributable to capital, operating, and maintenance costs of capital facilities associated with renewable energy systems used to meet the renewable energy standard.
- Costs that are not otherwise recoverable in rates approved by the Federal Energy Regulatory Commission and that are related to the infrastructure required to bring renewable energy systems used to achieve compliance with the renewable energy standards on to the transmission system, including interconnection and substation costs for renewable energy systems used to meet the renewable energy standard.
- Ancillary service costs determined by the commission to be necessarily incurred to ensure the quality and reliability of renewable energy used to meet the renewable energy standards, regardless of the ownership of a renewable energy system.
- Expenses incurred as a result of state or federal governmental actions related to renewable energy systems attributable to the renewable energy standards, including changes in tax or other law.
- Any additional electric provider costs determined by the commission to be necessarily incurred to ensure the quality and reliability of renewable energy used to meet the renewable energy standards.
- Subtract from the sum of costs not already included in electric rates determined under subdivision (a) PA 235 Section 47 2(a)(i-vii) – ex. transfer price, environmental attributes, interest on regulatory liability etc.

e) Recovery to include the authorized rate of return on equity, will remain fixed at the rate of return and debt to equity ratio that was in effect in base rates when the renewable plan was approved for any renewable energy system included in plans prior to February 27, 2024. For all renewable energy systems approved by the commission after amended plans are approved, the electric providers shall use it authorized rate of return to be recovered through base rates. (PA 235 Section 47(1)).

10. Tariff filings reflecting the cost recovery mechanism if applicable.

Michigan Public Service Commission
2023 Public Act 235

Filing Requirements and Instructions for Renewable Energy Plans for Alternative Electric Suppliers

PA 235 of 2023 Section 22 *Within 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 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.*

PA 235 of 2023 Section 28 (1) *An electric provider shall achieve a renewable energy credit portfolio of at least the following:*

(a) Through 2029, 15%.
(b) In 2030 through 2034, 50%.
(c) In 2035 and each year thereafter, 60%.

(2) An electric provider's renewable energy credit portfolio shall be calculated as follows:

(a) Determine the number of renewable energy credits used to comply with this subpart during the applicable year.

(b) Divide by 1 of the following at the option of the electric provider as specified in its renewable energy plan:

(i) The number of weather normalized megawatt hours of electricity sold by the electric provider during the previous year to retail customers in this state, less the amount of sales attributable to customers participating in an electric provider's voluntary green pricing program under section 61 and the outflow from customers participating in the distributed generation program under section 173 for that year.

(ii) The average number of megawatt hours 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 program under section 61 and the outflow from customers participating in the distributed generation program under section 173 for that year.

(c) Multiply the quotient under subdivision (b) by 100.

(5) Each electric provider shall meet the renewable energy credit standard, subject to subsection (3), with renewable energy credits 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.

The following suggests several elements that address the specific items to be included in the amended plan filings. These suggestions are intended to be used only as initial guidance. They are not necessarily exhaustive. For any sections that are not applicable, please state as such.

1. Detailed renewable resource plan.

    a. Forecast expected compliance levels by year to meet the renewable portfolio targets.
    b. Identify key assumptions used in developing these forecasts and the proposed resource portfolio.
    c. Identify risks which may drive performance to vary.

2. Sales forecast through 2045 for compliance with the renewable energy standard in PA 235 Section 28.

    a. Specify whether megawatt hours of electricity used in the calculation is weather-normalized or based on the average number of megawatt hours of electricity sold by the electric provider annually during the previous 3 years to full-service retail customers in the state.

3. Forecasted megawatt hour outflow from distributed generation customers through 2045.

    a. Specify if renewable energy credits from distributed generation outflow are utilized towards compliance with the standard.

4. Forecasted megawatt hours attributable to the voluntary green pricing program through 2045.

5. Quantity of renewable energy credits

    a. Outline the quantity of renewable energy credits the Company forecasts it must obtain each year to meet the renewable standard (PA 235 of 2023 Section 28(1)).
    b. Forecast of renewable energy credits subject to the 5% limit as defined by PA 235 Section 28(5)(c) through 2035.

c. Describe the Company’s planned renewable portfolio forecasted renewable energy credits obtained via the Michigan incentive renewable credits as provided for in PA 235 of 2023 Section 39.

Michigan Public Service Commission
2023 Public Act 235

Filing Requirements and Instructions
for Renewable Energy Plans
for Member-Regulated Electric Cooperatives

PA 235 of 2023 Section 22 Within 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 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.

PA 235 of 2023 Section 28 (1) An electric provider shall achieve a renewable energy credit portfolio of at least the following:

(a) Through 2029, 15%.
(b) In 2030 through 2034, 50%.
(c) In 2035 and each year thereafter, 60%.

(2) An electric provider's renewable energy credit portfolio shall be calculated as follows:

(a) Determine the number of renewable energy credits used to comply with this subpart during the applicable year.

(b) Divide by 1 of the following at the option of the electric provider as specified in its renewable energy plan:

(i) The number of weather normalized megawatt hours of electricity sold by the electric provider during the previous year to retail customers in this state, less the amount of sales attributable to customers participating in an electric provider's voluntary green pricing program under section 61 and the outflow from customers participating in the distributed generation program under section 173 for that year.

(ii) The average number of megawatt hours 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 program under section 61 and the outflow from customers participating in the distributed generation program under section 173 for that year.

(c) Multiply the quotient under subdivision (b) by 100.

(3) Notwithstanding subsection (1) and subject to subsection (4), in any year a cooperative electric provider or a multistate electric provider may calculate its maximum renewable energy credit portfolio requirement as follows:

(a) Determine the number of megawatt hours of electricity sold by the electric provider to retail customers in this state using the option the electric provider selected under subsection (2)(b).

(b) Subtract the number of megawatt hours of nuclear energy that the electric provider obtained from a system located in this state that the electric provider owned or from which the electric provider had contracted to receive nuclear energy on or before January 1, 2024.

(4) An electric provider described in subsection (3) is required to achieve a renewable energy credit portfolio equal only to the electric provider's maximum renewable energy credit portfolio requirement if the electric provider's maximum renewable energy credit portfolio requirement is less than the number of renewable energy credits required to comply with the applicable standard in subsection (1).

(5) Each electric provider shall meet the renewable energy credit standard, subject to subsection (3), with renewable energy credits 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.

The following suggests several elements that address the specific items to be included in the amended plan filings. These suggestions are intended to be used only as initial guidance. They are not necessarily exhaustive. For any sections that are not applicable, please state as such.

1. Detailed renewable resource plan.

   a. Forecast expected compliance levels by year to meet the renewable portfolio targets.
   b. Identify key assumptions used in developing these forecasts and the proposed resource portfolio.
   c. Identify risks which may drive performance to vary.

2. Sales forecast through 2045 for compliance with the renewable energy standard in PA 235 Section 28.

   a. Specify whether megawatt hours of electricity used in the calculation is weather-normalized or based on the average number of megawatt hours of electricity sold by the electric provider annually during the previous 3 years to full-service retail customers in the state.

3. Forecasted megawatt hour outflow from distributed generation customers through 2045.

a. Specify if renewable energy credits from distributed generation outflow are utilized towards compliance with the standard.

4. Forecasted megawatt hours attributable to the voluntary green pricing program through 2045.

5. Forecasted megawatt hours from nuclear energy for electric providers subject to PA 235 Sections (28)(3) and (4) through 2045.

6. Quantity of RECs

a. Outline the quantity of renewable energy credits (REC) the Company forecasts it must obtain each year to meet the RPS (PA 235 of 2023 Section 28(1)).

b. Forecast of RECs subject to the 5% limit as defined by PA 235 Section 28(5)(c) through 2035.

Michigan Public Service Commission
2023 Public Act 235

Filing Requirements and Instructions
for Renewable Energy Plans
For Municipally-Owned Electric Utilities

PA 235 of 2023 Section 22 Within 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 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.

PA 235 of 2023 Section 28 (1) An electric provider shall achieve a renewable energy credit portfolio of at least the following:

(a) Through 2029, 15%.

(b) In 2030 through 2034, 50%.

(c) In 2035 and each year thereafter, 60%.

(2) An electric provider's renewable energy credit portfolio shall be calculated as follows:

(a) Determine the number of renewable energy credits used to comply with this subpart during the applicable year.

(b) Divide by 1 of the following at the option of the electric provider as specified in its renewable energy plan:

(i) The number of weather normalized megawatt hours of electricity sold by the electric provider during the previous year to retail customers in this state, less the amount of sales attributable to customers participating in an electric provider's voluntary green pricing program under section 61 and the outflow from customers participating in the distributed generation program under section 173 for that year.

(ii) The average number of megawatt hours 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 program under section 61 and the outflow from customers participating in the distributed generation program under section 173 for that year.

(c) Multiply the quotient under subdivision (b) by 100.

The following suggests several elements that address the specific items to be included in the amended plan filings. These suggestions are intended to be used only as initial guidance. They are not necessarily exhaustive. For any sections that are not applicable, please state as such.

1. Detailed renewable resource plan.

a. Forecast expected compliance levels by year to meet the renewable portfolio targets.
b. Identify key assumptions used in developing these forecasts and the proposed resource portfolio.
c. Identify risks which may drive performance to vary.

2. Sales forecast through 2045 for compliance with the renewable energy standard in PA 235 Section 28.

a. Specify whether megawatt hours of electricity used in the calculation is weather-normalized or based on the average number of megawatt hours of electricity sold by the electric provider annually during the previous 3 years to full-service retail customers in the state.

3. Forecasted megawatt hour outflow from distributed generation customers through 2045.

b. Specify if renewable energy credits from distributed generation outflow are utilized towards compliance with the standard.

4. Forecasted megawatt hours attributable to the voluntary green pricing program through 2045.

5. Forecasted megawatt hours from nuclear energy for electric providers subject to PA 235 Sections (28)(3) and (4) through 2045.

6. Quantity of RECs

a. Outline the quantity of renewable energy credits (REC) the Company forecasts it must obtain each year to meet the RPS (PA 235 of 2023 Section 28(1)).

P R O O F   O F   S E R V I C E

STATE OF MICHIGAN)

Case No. U-21568

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on April 25, 2024 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 J. Brown

Brianna Brown

Subscribed and sworn to before me
this 25th day of April 2024.

Angela P. Sanderson

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2024

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