



July 9, 2025

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48909

Via E-File

RE: MPSC Case No. U-21859

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Rebuttal Testimony and Exhibit of Caroline Palmer on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (MEC-24); and
- Proof of Service.

Thank you for your assistance in this matter. If you have any questions, please feel free to contact me.

Sincerely,

Christopher M. Bzdok
chris@tropospherelegal.com

CC: Parties to Case No. U-21859

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
CONSUMERS ENERGY COMPANY for U-21859
ex parte approval of certain amendments to
Rate GPD.

REBUTTAL TESTIMONY OF CAROLINE PALMER
ON BEHALF OF
MICHIGAN ENVIRONMENTAL COUNCIL,
NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB, AND
CITIZENS UTILITY BOARD OF MICHIGAN

July 9, 2025

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1 **I. INTRODUCTION**

2 **Q. Please state for the record your name, position, and business address.**

3 A. My name is Caroline Palmer. I am a Principal Associate at Synapse Energy Economics,
4 Inc. (“Synapse”), located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

5 **Q. On whose behalf do you offer this testimony?**

6 A. I am testifying on behalf of Michigan Environmental Council (MEC), Natural Resources
7 Defense Council (NRDC), Sierra Club (SC), and Citizens Utility Board of Michigan
8 (CUB), collectively referred to as “MNSC.”

9 **Q. Are you the same Caroline Palmer who submitted direct testimony in this docket?**

10 A. Yes.

11 **Q. What is the purpose of your rebuttal testimony?**

12 A. I respond to the Data Center Coalition’s (DCC) direct testimony regarding minimum
13 contract term, minimum billing demand, capacity reduction, exit fee, and applicability. I
14 continue to recommend a 20-year contract term at a minimum billing demand of 90% of
15 contract capacity and that exit fee waivers and contract capacity reductions be subject to
16 Commission review and approval of Consumers’ demonstration that the reduction will not
17 harm other customers.

18 **Q. Are you sponsoring any exhibits?**

19 A. Yes, I am sponsoring the following exhibits:

20 Exhibit MEC-24: MISO LRTP Tranche 1 Portfolio Detailed Business Case, presented
21 on June 25, 2022

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1 **II. THE COMMISSION SHOULD NOT LOWER RATE GPD’S CONTRACT TERM**
2 **OR MINIMUM BILLING DEMAND**

3 **Q. Does DCC agree with Consumers’ proposed contract term and minimum billing**
4 **demand?**

5 A. No. DCC recommends that the Commission adopt a 10-year mandatory minimum contract
6 term and a monthly minimum billing demand equal to 70% of the customer’s contract
7 capacity,¹ rather than Consumers’ proposed 15-year minimum contract term and 80%
8 minimum billing demand.

9 **Q. How does DCC justify lowering Consumers’ proposed minimum contract term and**
10 **minimum billing demand?**

11 A. DCC notes that the proposed minimum contract term and minimum billing demand work
12 in conjunction with generation, transmission, and distribution demand charges to establish
13 minimum payment obligations for data center customers. Based on its calculations, DCC
14 argues that the minimum incremental long-term revenues from Rate GPD transmission
15 charges – resulting from customers paying the minimum billing demand over the minimum
16 contract term – will greatly exceed the incremental long term revenue requirements
17 associated with estimated transmission investments.² Specifically, DCC calculates that the
18 estimated net present value (NPV) revenue requirement for new transmission infrastructure
19 investment to serve 2.65 GW of data center load is \$1.046 billion, which is less than the

¹ Direct Testimony of Justin Bieber, p.6.

² Direct Testimony of Justin Bieber, p.26-30.

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1 NPV transmission revenue that DCC estimates would be collected under Consumers’
2 proposal (\$2.128 billion) or DCC’s proposal (\$1.383 billion).³

3 **Q. What are your concerns with DCC’s analysis?**

4 A. I am concerned that DCC has 1) only considered the incremental transmission investments
5 needed to serve an additional 2.65 GW of data center load, rather than the full set of
6 transmission resources required to serve the load and 2) only attempted to evaluate
7 transmission costs, when its recommendations would impact other significant system costs.
8 I address each concern sequentially.⁴

9 **Q. Explain your concern that DCC only considered incremental transmission**
10 **investments.**

11 A. DCC’s calculation that serving 2.65 GW of data center load requires a \$1.046 billion
12 transmission revenue requirement is based on the Transmission Owner’s estimate of the
13 transmission infrastructure investment required to support 2.65 GW of large load
14 additions.⁵ DCC acknowledges that this transmission infrastructure investment would be
15 “new” and “incremental” to the currently planned and approved transmission system.⁶
16 However, it is unreasonable to compare data center customers’ expected transmission
17 revenues to only the *incremental* transmission investments they require.

³ Direct Testimony of Justin Bieber, p.30.

⁴ In identifying these two concerns, I have assumed but not had time to independently evaluate the reasonableness and accuracy of the various assumptions underlying witness Bieber’s NPV calculations - such as the chosen discount rate, GPD Rate annual escalation, and transmission revenue requirement levelized cost calculations.

⁵ Consumers Response to Discovery U21859-DCC-CE-0006.

⁶ Direct Testimony of Justin Bieber, p.26.

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1 The new large customers will likely also utilize and benefit from the existing and planned
2 transmission system, but DCC does not account for those embedded system costs. DCC
3 instead concludes that because paying embedded system pricing would result in revenues
4 that exceed *incremental* system costs, “it is not necessary to impose a 15-year Minimum
5 Contract Term and 80% Minimum Billing Demand on new large load customers.”⁷ DCC
6 even argues that “incremental generation or transmission assets provide benefits to both
7 new and existing customers,”⁸ yet DCC does not acknowledge that existing assets also
8 provide benefits to new customers and that the additional load from new customers will
9 likely impose additional wear and tear on existing assets, reducing their lifespan and
10 efficiency.⁹ Similarly, when DCC touts that “revenues from new large load customers
11 contribute to the cost recovery of both new and existing assets,” it does not acknowledge
12 that the customers *should* pay for the existing assets that they also benefit from.¹⁰

13 Finally, even DCC’s incremental cost estimate is likely understated, given that the
14 transmission owner’s estimate does not include additional transmission infrastructure
15 required to interconnect additional generation to support the load.¹¹

⁷ Direct Testimony of Justin Bieber, p.31.

⁸ Direct Testimony of Justin Bieber, p.33.

⁹ Additional load from data centers will increase load on a variety of equipment, causing it to operate closer to capacity and increasing the temperature of the equipment. This temperature increase results in greater losses and reduced lifespan of the equipment. *See*, for example, Copper Development Association, Inc. “Temperature Rise and Transformer Efficiency.” Available at: https://copper.org/environment/sustainable-energy/transformers/education/trans_efficiency.php.

¹⁰ Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities. 136 FERC ¶ 61,051 at P 535: “the cost causation principle provides that costs should be allocated to those who cause them to be incurred and those that otherwise benefit from them”

¹¹ U21859-DCC-CE-0006.

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1 **Q. How might the existing and planned transmission system serve data centers?**

2 A. The Midcontinent Independent System Operator (MISO) is currently in the process of
3 implementing Tranche 1 of its Long-Range Transmission Plan (“LRTP”), which increases
4 transmission capacity across North and Central MISO. Tranche 1 includes 18 projects
5 across the MISO Midwest subregion estimated at \$10.3 billion, including over \$1 billion
6 for two projects in Michigan. The projects have been justified based on the benefits that
7 they offer, including the avoided capital costs of local resource investments. LRTP Tranche
8 1 projects increase regional transfer capability, resulting in an optimized balance of local
9 resource investment and regional transmission capacity.¹² MISO estimates that the
10 economic value unlocked by the availability of least-cost resources across the footprint due
11 to an increase in transfer capability from the LRTP yields 20-to 40-year present value
12 benefits from \$624-\$893 million.¹³ MISO entirely attributes these savings to Zone 7, where
13 Consumers Energy is located. Neither Consumers nor DCC appear to have made an
14 assessment of any changes in the Zone 7 capacity import limits that might result from
15 development of data center load and associated supply resources, such as consuming a
16 portion of the capacity import limit and therefore reducing – or absorbing – some of those
17 estimated LRTP benefits that would have been experienced by existing customers.

18 Another LRTP benefit is increased regional transmission capacity, which can preempt the
19 need for reliability expansion projects and upgrades in the future.¹⁴ MISO estimated the

¹² https://d3u3c9e6sbajfk.cloudfront.net/wp-content/uploads/2023/10/LRTP_ITC-MI-FACT-SHEET-_Final-082523.pdf.

¹³ Exhibit MEC-24, MISO LRTP Tranche 1 Portfolio Detailed Business Case, presented on June 25, 2022, slides 27, 57-58.

¹⁴ https://d3u3c9e6sbajfk.cloudfront.net/wp-content/uploads/2023/10/LRTP_ITC-MI-FACT-SHEET-_Final-082523.pdf.

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1 NPV of the avoided cost of reliability upgrades and replacements that will not be required
2 in the future as a result of the addition of LRTP projects, projecting 20-to 40-year present
3 value benefits from \$1.3 billion to \$1.9 billion. At the low end of that range, \$74 million
4 of the \$1.3 billion estimated benefits flows to MISO local resource Zone 7.¹⁵ Some of these
5 avoided reliability upgrades and replacements may have reduced the transmission owner's
6 estimate of the cost to serve 2.65 GW of new data center load.

7 **Q. Explain your concern that DCC only evaluated transmission costs when**
8 **recommending a shorter contract term and lower minimum billing demand.**

9 A. DCC seeks to prove that data center customers will overpay for power system costs under
10 Consumers' proposed contract term and minimum billing demand but only evaluates
11 transmission system costs and revenues – using a flawed measure of transmission system
12 costs, as discussed above – when Consumers will likely incur equally if not more
13 significant generation costs to serve data center customers. DCC does not evaluate
14 generation costs because “the Company has not performed the analyses that would be
15 necessary to identify incremental generation investments to serve new large loads.”¹⁶
16 While this is true, the magnitude of potential generation costs necessitates considering
17 them, too, when evaluating a proposal as impactful as DCC's.

¹⁵ Exhibit MEC-24, MISO LRTP Tranche 1 Portfolio Detailed Business Case, presented on June 25, 2022, slides 31, 57-58.

¹⁶ Direct Testimony of Justin Bieber, p.26.

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1 **Q. Have you estimated hypothetical incremental generation costs associated with large**
2 **load customers?**

3 A. Yes. To enable a comparable generation analysis to DCC’s transmission analysis, I’ve
4 estimated a basic, hypothetical generation cost.¹⁷ I have assumed the Company would
5 invest in new combined cycle units, estimated at \$2,400/kW,¹⁸ to meet the new load. The
6 baseload capabilities of combined cycle plants enable them to meet the high energy
7 requirements of high load factor customers.¹⁹ I maintain DCC’s assumption of 2.65 GW
8 of new large load; however, the new combined cycle capacity needed to serve such level
9 of new load would be higher than 2.65 GW because Consumers would need to factor in
10 MISO’s Zone 7 reserve margin²⁰ and combined cycle capacity accreditation.²¹ Once those
11 factors are accounted for, the amount of new generating capacity that would be needed to
12 serve 2.65 GW of data center load would be approximately 3.38 GW.²² Thus, a reasonable
13 estimate of the installed capital cost of serving the new data center load is \$8.1 billion.²³
14 This estimate does not include any potential carbon capture and sequestration costs that

¹⁷ I presented some back-of-the envelope generation cost calculations in my direct testimony (p.27-29), intended to highlight the potential relative magnitude of incremental generation costs to serve data centers compared to current generation costs. I have refined those numbers for this more targeted analysis of data center costs versus revenues. For example, I updated the \$/kW resource cost based on a more recent industry source and incorporated MISO capacity requirements to reflect likely investment conditions. I do not use the Company’s PPA cost estimate for this targeted analysis because Consumers indicated that the estimate was not necessarily scalable.

¹⁸ <https://gasoutlook.com/analysis/costs-to-build-gas-plants-triple-says-ceo-of-nextera-energy/>.

¹⁹ While I focus here on a single resource option – combined cycle gas units – as a simplifying assumption for this analysis, Consumers should evaluate other resource options, such as renewables paired with battery storage, when it carries out its resource planning for determining the most reasonable and prudent way to meet whatever data center load growth the utility ends up experiencing.

²⁰ <https://cdn.misoenergy.org/20231017%20LOLEWG%20Item%2003%20PY%202024-25%20LOLE%20Study%20Results630538.pdf>.

²¹ I used the summer capacity accreditation value of 91%. <https://www.in.gov/iurc/files/MISO-Resource-Accreditation-Reform-IRP-Contemporary-Issues-Technical-Conference-06062024.pdf>.

²² 2.65 GW * (1 + 0.161 reserve margin) / 0.91 capacity accreditation = 3.38 GW

²³ 3,381 MW * \$2,400/kW * 1,000 = \$8,114,241,758.

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1 would be needed for the gas combined cycle units to qualify as “clean energy” under
2 Michigan’s Clean Energy Standard.²⁴

3 **Q. How do the minimum generation revenues from data center customers compare to**
4 **the incremental generation costs?**

5 A. Using DCC’s workpapers to enable direct comparison, I replaced the weighted average
6 transmission \$/kW demand charge with the generation \$/kW demand charge, as well as
7 substituted Consumers’ WACC, 5.97%,²⁵ for Michigan Electric Transmission Company’s
8 rate of return. Per Table 1, the NPV of generation revenues expected from large Rate GPD
9 customers over Consumers’ proposed minimum contract term and minimum billing
10 demand total \$4.6 billion. Under DCC’s proposal, I calculated that expected generation
11 revenues would fall to \$2.9 billion. These revenues are about \$3.5 billion and \$5.2 billion
12 lower, respectively, than the installed capital costs of the incremental generation capacity.
13 Those amounts are significantly higher than the transmission revenue surplus that DCC
14 calculated.

15 Table 1: Minimum Generation Revenues under Consumers and DCC proposals

<u>Minimum Generation Revenues</u>	<u>Consumers Proposal</u>	<u>DCC Proposal</u>
Minimum Contract Term (Years)	15	10
Minimum Billing Demand (%)	80%	70%
Large Load Additions (MW)	2,650	2,650
GPD 1 Rate (\$/kW)(weighted avg summer/winter)	15.68	15.68
Annual Minimum Demand Charges (\$)	398,899,200	349,036,800
Proxy Discount Rate (%)	5.97%	5.97%
GPD Rate Annual Escalation	2.7%	2.7%
NPV of Minimum Demand Charges (\$)	4,572,954,831	2,870,895,648

²⁴ MCL 460.1003(e), (i), and 460.1051.

²⁵ Commission Order in Case No. U-21585, p. 433. March 21, 2025.

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1 **Q. What are the minimum generation revenues under your recommended 20-year**
2 **contract term and 90% minimum billing demand?**

3 A. I previously recommended a 20-year contract term at a minimum billing demand of 90%
4 of contract capacity.²⁶ Under those parameters, I calculated that the minimum NPV
5 generation revenues expected from large Rate GPD customers would be \$6.4 billion, or
6 \$1.7 billion lower than the incremental generation capital cost I identified.

7 **Q. Have you calculated the NPV of the generation revenue requirement?**

8 A. Yes. I estimated a levelized, annual revenue requirement based on a 40-year book life and
9 using Consumers' WACC. I calculate the 40-year NPV of the upfront capital cost to be
10 \$8.6 billion. This approach also allows for calculating the NPV of a shorter period of
11 levelized costs. For example, the NPV of the levelized costs for 15 years out of the 40-year
12 life would total \$5.5 billion. Thus, even if a new large load customer replaced the original
13 customer after the 15-year term and began paying equivalent generation demand costs –
14 which of course cannot be guaranteed – the original customer would need to contribute
15 \$5.5 billion in revenues to cover their portion of the levelized costs. Per the calculation
16 above, revenues under Consumers' proposal would be roughly \$1 billion short of that
17 target. Alternatively, the NPV of the levelized costs for just 10 years out of the 40-year life
18 would total \$4.2 billion. DCC's proposal would fall short of that target by more than \$1.3
19 billion. Although I do not support assuming that a replacement customer will smoothly
20 substitute for the original customer after their contract term, these calculations demonstrate
21 that the hypothetical data center customers under both DCC's and Consumers' proposals

²⁶ Direct Testimony of Caroline Palmer, p.4.

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1 would not even contribute the cost of the levelized revenue requirement attributable to their
2 generation needs during the life of their contract term.

3 **Q. What do you conclude regarding DCC’s recommended contract term and minimum
4 billing demand?**

5 A. Although DCC states that Consumers’ proposal “is excessive and not supported and should
6 be rejected,”²⁷ DCC’s proposal is insufficient and not supported and should be rejected. I
7 continue to recommend a 20-year contract term at a minimum billing demand of 90% of
8 contract capacity.

9 **III. THE COMMISSION SHOULD NOT LOWER THE EXIT FEE PERIOD OR
10 PERMIT REFUNDS**

11 **Q. Describe DCC’s exit fee recommendations.**

12 A. DCC recommends modifying the Exit Fee to be calculated as the Minimum Billing
13 Demand multiplied by the lesser of 60 months or the remaining months in the Contract
14 Term. DCC further recommends that data center customers receive refunds of Exit Fees
15 that are paid if Consumers later manages to mitigate the costs.²⁸

16 **Q. Describe your concerns with DCC’s exit fee recommendations.**

17 A. As with its contract term and minimum billing demand recommendations, DCC justifies
18 its exit fee period recommendation based on incremental transmission costs. As I discussed
19 above, the transmission cost estimate should not only be limited to the incremental
20 transmission investment required to serve data center customers. Further, I demonstrated

²⁷ Direct Testimony of Justin Bieber, p.34.

²⁸ Direct Testimony of Justin Bieber, p.46.

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1 that when evaluating hypothetical generation costs – even when limited to incremental
2 generation costs – data center customers will not contribute sufficient revenues over the
3 proposed 15-year term to pay for the annual, levelized costs associated with those 15 years.

4 In the event that Consumers cannot mitigate the exit fee payment, data center customers
5 should therefore certainly continue to be held responsible for paying system costs for the
6 entire period of their original contract.

7 Regarding the recommendation to refund a customer if Consumers subsequently reassigns
8 the capacity or otherwise mitigates associated costs, it is reasonable to refund a customer
9 if Consumers subsequently reassigns the capacity to a new or expanded data center
10 customer. However, if Consumers secures capacity- and energy-market revenues, those
11 should be allocated among the customer classes consistent with Consumers’ established
12 revenue allocation practices, not preferentially allocated to data center customers.
13 Consumers cannot use a specific amount of market revenues to offset a particular portion
14 of data center costs, given that the Company proposes to treat its entire power system as a
15 shared resource. This might be different if Consumers attributed specific costs to data
16 centers and directly assigned them. Given that data center customers would have paid into
17 the shared system costs (via their exit fee), it would be reasonable to make them eligible
18 for Rate GPD’s allocation of the system benefits, though likely administratively
19 burdensome to do so, given potential required departure from established practice.

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1 **IV. THE COMMISSION SHOULD NOT PERMIT A 15% ONE-TIME CAPACITY**
2 **REDUCTION**

3 **Q. Describe DCC’s recommendation regarding a one-time capacity reduction.**

4 A. DCC recommends that the Commission allow large customers on Rate GPD a one-time
5 capacity reduction equal to 15% of the contract capacity, without any review or approval
6 by Consumers or the Commission and without payment of any exit fee, provided that the
7 customer provides written notice of the requested reduction at least 36 months in advance.

8 **Q. Would a one-time capacity reduction risk harming other customers?**

9 A. Yes. If, for example, a 667 MW facility reduced its capacity by 15%, the reduction would
10 total 100 MW, or the entire capacity of a small Rate GPD data center customer. The 15%
11 reductions of even larger facilities would of course exceed the size of some Rate GPD data
12 center customers. Given that Consumers and stakeholder have deemed it necessary to
13 protect against the departure of 100 MW of load – or even less – via the numerous
14 provisions at issue in this case, it is not reasonable to allow a customer to eliminate such a
15 substantial amount of load. I continue to recommend, per my direct testimony, that exit fee
16 waivers and contract capacity reductions be subject to Commission review and approval of
17 Consumers’ demonstration that the reduction will not harm other customers.

18 **V. APPLICABILITY**

19 **Q. DCC argues that Consumers’ proposed Rate GPD data center provisions should**
20 **apply to all large new loads, not just data centers. Do you agree?**

21 A. Some of the issues that arise with new large data center load also arise with large new loads
22 in different lines of business, but some are unique to data centers. I do not object to the

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1 application of provisions arising from this case to other new large loads, but I also
2 recognize that there are some risks to Consumers' other customers that are more specific
3 to data centers.

4 **Q. What issues are common to large new loads, whether for data centers or other lines**
5 **of business, that necessitate robust consumer protections?**

6 A. Large new loads that trigger resource additions beyond normal load growth will typically
7 require significant and costly incremental transmission infrastructure and generation
8 resources. These conditions make it likely that allocation of these new costs using
9 Consumers' typical cost of service methods will increase the costs assigned to existing
10 customers in various classes. This will be true whether the large new load is a data center
11 or some other type of facility.

12 **Q. Are there issues that are more specific to data centers?**

13 A. Yes. Consumers' application highlighted specific risks associated with data centers.²⁹
14 Although DCC is correct that Consumers did not provide specific evidence to demonstrate
15 that data centers are more inclined to reduce or eliminate electric loads, rapid development
16 of hyperscale data centers is an unprecedented phenomenon, and thus there cannot be much
17 relevant evidence. However, there have been cases of significant change in data center
18 operator plans. Microsoft recently cancelled about 2 GW of announced data center
19 projects.³⁰ Amongst the data centers cancelled by Microsoft were three data centers in
20 Ohio, one of which had been granted a tax abatement and set to commence construction in

²⁹ Connolly Direct p. 9-10.

³⁰ Data Center Dynamics, published on March 27, 2025, available from <https://www.datacenterdynamics.com/en/news/microsoft-cancels-up-to-2gw-of-data-center-projects-says-td-cowen/>.

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1 July 2025.³¹ Industry literature also considers data center customers to have a higher
2 likelihood of shifting to a different location if grid or economic conditions are not
3 favorable, compared to manufacturing facilities or conventional commercial and industrial
4 loads.³²

5 Although I do not consider it unreasonable to apply Consumers' provisions to other large
6 new loads, there is a clear need for robust consumer protections and reevaluation of cost
7 allocation methods in light of any large, unprecedented, and risky new potential customers.

8 **Q. Does that complete your testimony?**

9 A. Yes.

³¹ <https://www.benzinga.com/25/04/44733013/microsoft-shelves-1-billion-ohio-data-center-plans-amid-global-project-withdrawals-we-are-slowing-or-pausing-some-early-stage-projects>.

³² Jeffrey Sward, Lauren Shwisberg, Katerina Stephan, and Jacob Becker, Get a Load of This: Regulatory Solutions to Enable Better Forecasting of Large Loads, RMI, 2025, <https://rmi.org/insight/get-a-load-of-this>. p. 6.



LRTP Tranche 1 Portfolio Detailed Business Case

June 25, 2022

Summary



- Long Range Transmission Planning (LRTP) addresses the future challenges of the resource fleet evolution
- The LRTP Detailed Business Case summarizes the analysis of the reliability and economic benefits used to demonstrate that the value exceeds the total cost of the projects and supports recommendation of the portfolio
- The LRTP Tranche 1 portfolio provides a total 20-year present value benefit to cost ratio of 2.6

MISO Transmission Planning Objectives

- The goal of MISO Planning is to identify and support development of transmission infrastructure that is sufficiently robust to meet reliability needs and support a competitive energy market, policy goals and competitive transmission development
- MISO Board of Directors Guiding Principles
 - Ensure a reliable and resilient transmission system to meet operational needs
 - Make benefits of an economically efficient electricity market available to customers by identifying transmission solutions that enable access to the electricity at the lowest total electric system cost
 - Support federal, state and local energy policy and member goals by planning for access to a changing resource mix
 - Provide an appropriate cost allocation mechanism that ensures that costs are allocated in a manner roughly commensurate with the projected benefits
 - Analyze system scenarios and make results available to energy policy makers and stakeholders to provide context and inform their choices
 - Coordinate planning process with neighbors and work to eliminate barriers to reliable and efficient operations

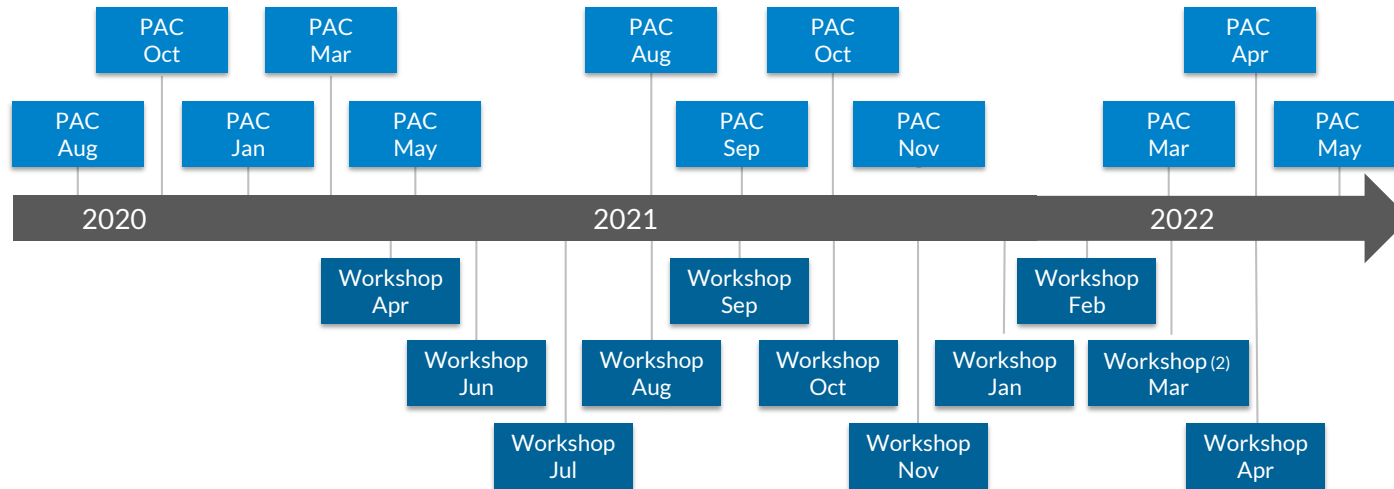
Long range focus on system planning needed in response to unprecedented industry changes

- The initial 2019 MISO Forward report began to examine industry trends around resource and technology developments that highlighted growing challenges around resource availability, flexibility and visibility of the resource fleet in meeting future energy needs
- The Renewable Integration Impact Assessment explored challenges of increased renewable penetration and identified significant reliability issues that would need to be addressed through possible reinforcements to maintain robust performance
- In recognition of the need for more long-term proactive planning to meet the pace of change, Long Range Transmission Planning began with a conceptual roadmap of ideas to help guide development of planning analysis that would be needed to identify possible transmission solutions

Timeline of LRTP development

- MISO introduced the LRTP conceptual roadmap to stakeholders in June 2020 to begin discussions on the study scope and approach
- MISO began a series of technical discussions in Aug 2020 to seek input from stakeholders on the study methods and assumptions and to provide regular status updates on the ongoing work and analysis findings
- MISO initiated discussions on cost allocation mechanisms with the Regional Expansion Criteria and Benefits Working Group in Feb 2021 to investigate possible Tariff changes that would be needed before recommendation of projects
- MISO introduced Business Case development in the Sept 2021 LRTP workshop to begin identifying the benefit components and defining the metrics for quantifying the benefits provided by the initial portfolio of LRTP transmission investments

Workshops and Stakeholder feedback are critical to the LRTP process and success



L RTP Projects must meet one of three MVP criteria defined in the MISO Tariff

MISO Tariff - Attachment FF, II.C.2...

- a. *Criterion 1. A Multi-Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade*
- b. *Criterion 2. A Multi-Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit -to-Cost ratio is described in Section II.C.7 of this Attachment FF. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value.*
- c. *Criterion 3. A Multi-Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.7 of Attachment FF.*

The MISO MVP Tariff further defines the ‘specific types of economic value’ which may be included

MISO Tariff - Attachment FF, II.C.5...

- a. Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be realized through reductions in both transmission congestion and transmission energy losses. Production cost savings can also be realized through reductions in Operating Reserve requirements within Reserve Zones and, in some cases, reductions in overall Operating Reserve requirements for the Transmission Provider.*
- b. Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.*
- c. Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.*
- d. Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.*
- e. Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the transmission system and related to the provisions of Transmission Service.*

The objective of LRTP is to enable reliable and economic delivery of energy in the future with lower-carbon resources

Provide a cost-effective solution to allow future resources to serve load throughout the footprint

Enable access to lower-cost energy production

Provide more flexibility in fuel mix for customer choice

Maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply

The scope of LRTP business case analysis includes quantifying the reliability and economic benefits

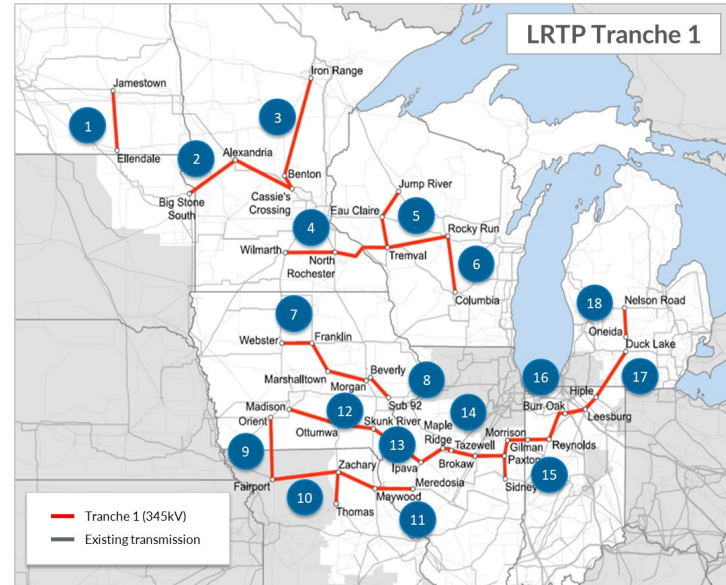
- A. Congestion and fuel savings
- B. Avoided capital costs of local resource investments
- C. Avoided transmission investment
- D. Reduced resource adequacy requirements
- E. Avoided risk of load shedding
- F. Decarbonization
- G. Reliability issues addressed by LRTP
- H. Other qualitative and indirect benefits

LRTP business case analysis uses a range of variables

- LRTP benefits examine value over the 20- to 40-year period from the in-service date (All projects assumed in service by 2030)
 - Benefit/cost calculations are evaluated on a 20-year time horizon
 - Additional benefits are shown for the 40-year horizon to align with assumed life of the assets
- LRTP benefits are evaluated for a range of discount rates from 3.0 – 6.9%
 - The social discount rate of 3.0% represents the value a ratepayer would typically receive on their risk-adjusted investment
 - The Weighted Average Cost of Capital (WACC) of 6.9% is the gross-plant weighted average of the Transmission Owners' cost of capital and represents the minimum return required on their transmission investments

Tranche 1 Portfolio proposal is the culmination of two years of Futures development, modeling, and engineering and represents the most complex transmission planning study effort in MISO's history

- Portfolio embodies needed transmission for the ever-changing fleet
- Addresses needs across the MISO Midwest subregion
- Analysis of reliability needs and benefits associated with Future 1 resource expansion



Total portfolio cost estimate for LRTP Tranche 1 is \$10.3 B for projects located across the MISO Midwest subregion

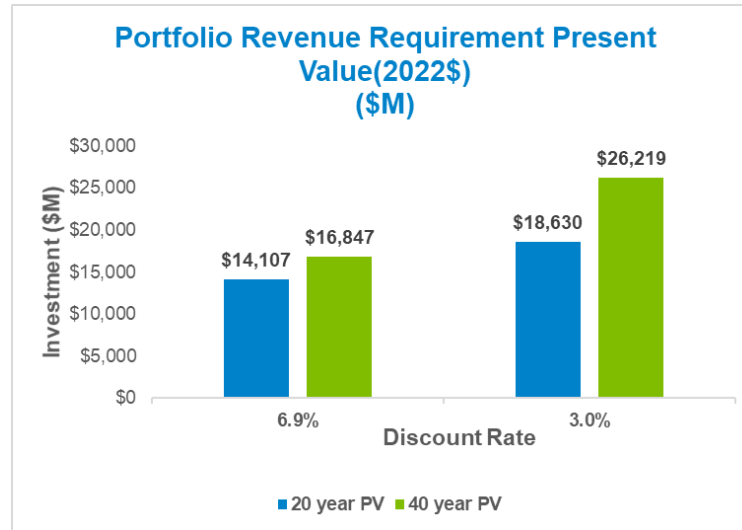
ID	Project Description	Est. Cost (\$M, 2022)
1	Jamestown - Ellendale	\$439
2	Big Stone South - Alexandria - Cassie's Crossing	\$574
3	Iron Range - Benton County - Cassie's Crossing	\$970
4	Wilmarth - North Rochester - Tremval	\$689
5	Tremval - Eau Clair - Jump River	\$505
6	Tremval - Rocky Run - Columbia	\$1,050
7	Webster - Franklin - Marshalltown - Morgan Valley	\$755
8	Beverly - Sub 92	\$231
9	Orient - Denny - Fairport	\$390
10	Denny - Zachary - Thomas Hill - Maywood	\$769
11	Maywood - Meredosia	\$301
12	Madison - Ottumwa - Skunk River	\$673
13	Skunk River - Ipava	\$594
14	Ipava - Maple Ridge - Tazewell - Brokaw - Paxton East	\$572
15	Sidney - Paxson East - Gilman South - Morrison Ditch	\$454
16	Morrison Ditch - Reynolds - Burr Oak - Leesburg - Hiple	\$261
17	Hiple - Duck Lake	\$696
18	Oneida - Nelson Rd.	\$403
Total Project Portfolio Cost		\$10,324

Costs as of 7/25/2022
 (costs represent "overnight" costs)

The LRTP Tranche 1 portfolio cost (20-year and 40-year present value at 6.9% and 3.0% discount rate)

The total capital cost of LRTP Tranche 1 portfolio is estimated to be \$10.3B

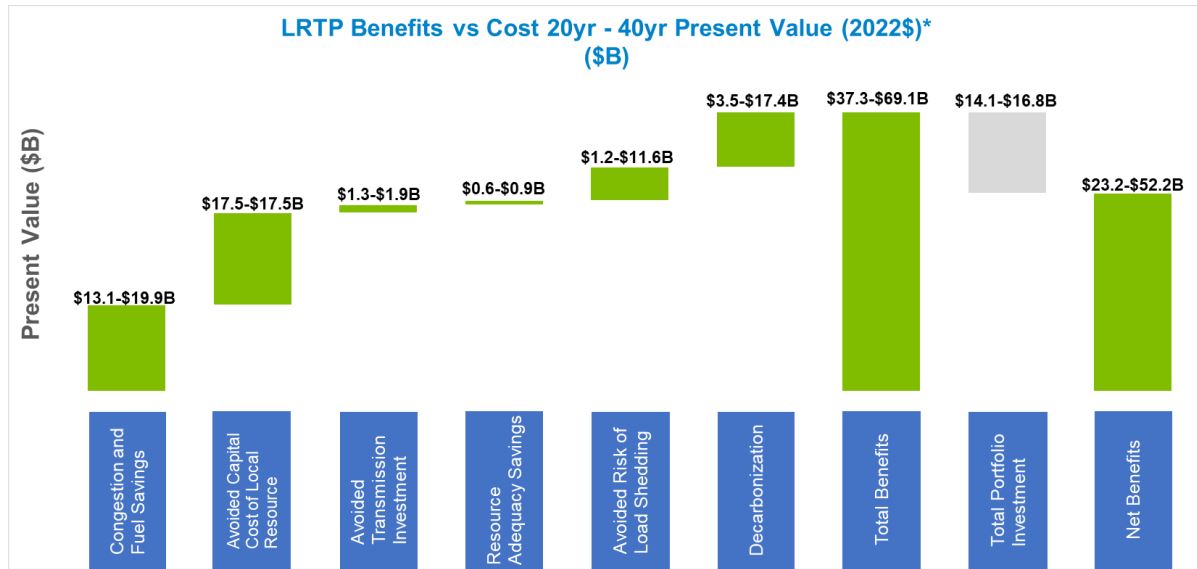
The 20-40yr Present Value (in 2022\$) of the portfolio total revenue requirement is expected to be in the range of \$14.1B-\$16.8B*



*6.9% Discount Rate

Benefit Metrics

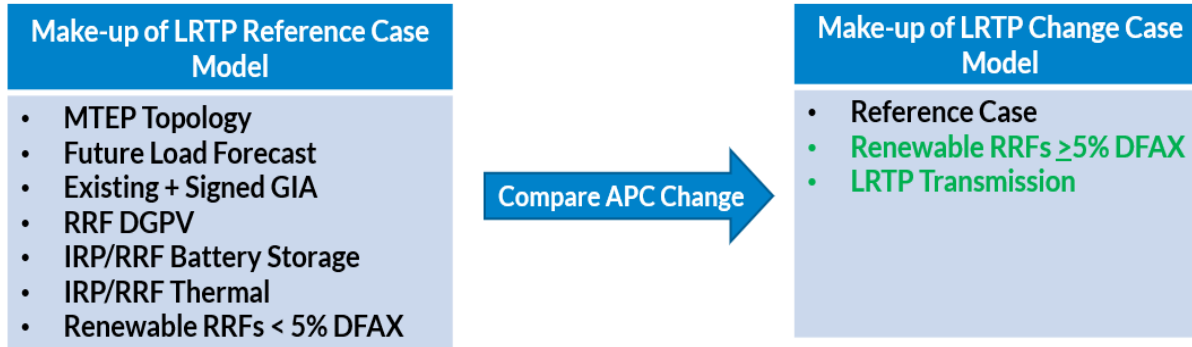
The business case analysis indicates total economic benefits significantly exceed cost of the Tranche 1 LRTP portfolio



*6.9% Discount Rate

A. Congestion and Fuel Savings

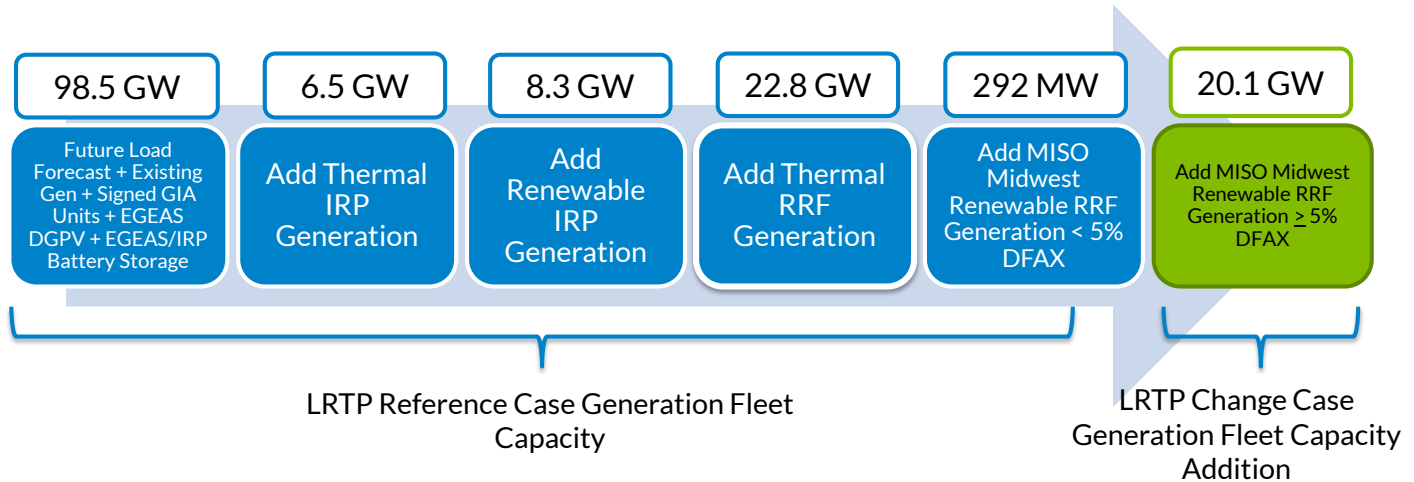
APC Benefits will be determined by comparing MISO Midwest APC in the LRTP Reference Case with the MISO Midwest APC in the LRTP Change Case



- The LRTP Reference Case represents necessary generation to serve Futures Load Forecast (on copper sheet)
- The LRTP Change Case includes Renewable RRFs located in MISO Midwest which have $\geq 5\%$ DFAX on reliability constraints addressed by LRTP projects

A. Congestion and Fuel Savings

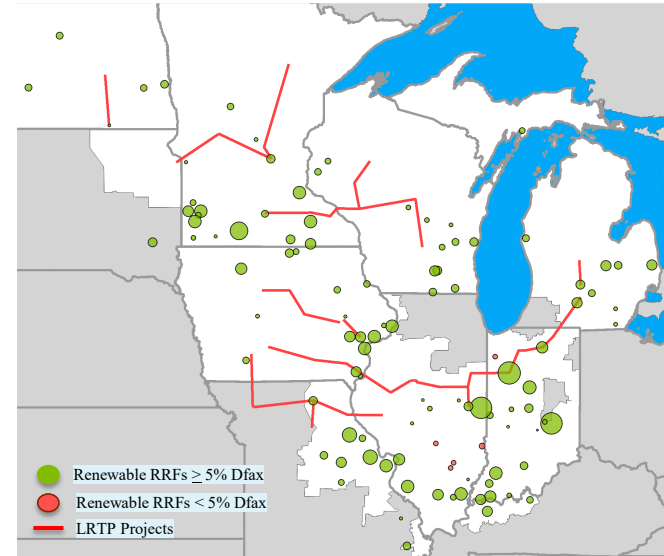
MISO Midwest-focused Reference Case generation determination process and results to meet copper sheet energy requirements in Future 1



A. Congestion and Fuel Savings

LRTP Tranche 1 projects congestion and fuel savings results

Present Value	20 year PV (Millions-2022\$)		40 year PV (Millions-2022\$)	
Discount Rate	6.9%	3.0%	6.9%	3.0%
CAZ				
1	\$3,169	\$4,455	\$4,668	\$8,797
2	\$1,049	\$1,511	\$1,667	\$3,313
3	\$2,195	\$3,060	\$3,151	\$5,823
4	\$1,352	\$1,934	\$2,107	\$4,133
5	\$1,471	\$2,078	\$2,205	\$4,210
6	\$2,884	\$4,133	\$4,517	\$8,890
7	\$1,006	\$1,432	\$1,543	\$2,993
	\$13,125	\$18,603	\$19,858	\$38,160



B. Avoided Capital Costs of Local Resource Investments

Resource capital investments can be avoided by taking advantage of broader regional renewables instead of purely local resources

- Past experiences with transmission studies like the 2011 Multi-Value Projects indicate that a regional approach will be more cost-effective than a purely local buildout:
 - Magnitude, cost, & locations of resources differ based upon approach used
 - Regional transmission is the bridge between these scenarios
- To determine avoided capital cost of local resource investment savings created by LRTP transmission MISO developed
 - EGEAS LBA (local) granularity expansion models utilizing Future 1 assumptions
 - Calculation to relate the LBA and Regional expansion to LRTP transmission and determine what the avoided capital costs of local resource investments would be

B. Avoided Capital Costs of Local Resource Investments

Overview of EGEAS LBA expansion models used to determine what a local build out would be

- Each EGEAS run represents one of the 39 LBAs in MISO, with a Future 1 basis
 - The runs treat each LBA as its own pool.
 - Each LBA then self-constructs resources necessary to meet the simulation constraints such as PRM and emissions.
 - Utilizes the same assumptions as the regional Future 1 analysis and resources are ascribed to LBAs based on resource ownership.
 - Capacity purchases are enabled for the first year to meet each LBA's PRM and is driven by the construction lead time for new resource alternatives.
 - LBA-specific wind and solar profiles are used instead of the regional profiles which averaged multiple profiles from different locations across MISO.
- The MISO PRM value of 18% is scaled for each LBA based upon its alignment to the MISO coincident peak.

B. Avoided Capital Costs of Local Resource Investments

Calculation to relate the LBA and Regional expansion to LRTP transmission to determine cost savings

- Calculation Overview
 - Due to Regional and LBA modeling assumptions, the avoided capital costs of local resources investments can not be determined by subtracting Regional expansion costs from the total LBA expansion costs (doing so would over-state realized benefit)
 - Regional and LBA Regional Resource Forecasting (RRF) expansion reflects Local Resource Zones (LRZ) that make up MISO Midwest (LRZ 1 – LRZ 7)
 - Enabled RRF capacity reflects RRF resources enabled by LRTP transmission, meaning those resources have $\geq 5\%$ Dfax for LRTP transmission resolved reliability issues
 - Utilizes costs of LRTP transmission enabled capacity to infer avoided capital cost of local resources savings

Adjusted Capital Cost_{LBA Expansion}

$$= \sum_{\text{Year } 2020}^{\text{Year } 2040} \text{Enabled RRF Capital Cost}_{\text{Region Expansion}} \times \frac{\sum_{\text{LRZ } 1}^{\text{LRZ } 7} (\text{Total RRF Capacity}_{\text{LBA Expansion}})}{\sum_{\text{LRZ } 1}^{\text{LRZ } 7} (\text{Total RRF Capacity}_{\text{Regional Expansion}})}$$

Avoided Capital Cost of Local Resource Investments

$$= \text{Adjusted Capital Cost}_{\text{LBA Expansion}} - \text{Enabled RRF Capital Cost}_{\text{Region Expansion}}$$

B. Avoided Capital Costs of Local Resource Investments

Avoided capital costs of local resource investments benefit

*Adjusted Capital Cost*_{LBA Expansion}

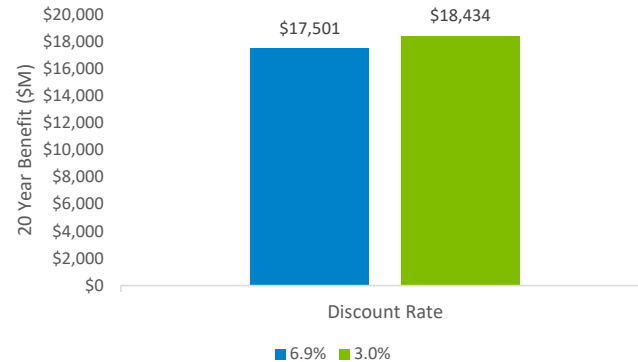
$$= \sum_{\text{Year 2020}}^{\text{Year 2040}} \$16.0B \times \frac{90,969 \text{ MW}}{43,431 \text{ MW}} = \$33.58B$$

Avoided Capital Cost of Local Resource Investments

$$= \$33.58B - \$16.0B = \$17.5B$$

- LRTP enables regional resource sharing and reduces local overbuild yielding a 20-year present value benefit of \$17.5B*

Avoided Capital Costs of Local Resource Investments (2022\$)



C. Avoided Transmission Investment

Transmission investment is avoided by developing regional solutions vs incremental fixes

- Captures the avoided cost of reliability upgrades and replacements that will not be required in the future as a result of the addition of LRTP projects
- Includes facilities where thermal loading is approaching the rating but not overloaded
 - Avoided reliability upgrades are determined by using the 10-year and 20-year analysis results to project future loading on facilities loaded near the rating with and without LRTP projects

$$\text{Flow}_{\text{proj}} = \text{Flow}_{20} + (\text{Flow}_{20} - \text{Flow}_{10})$$

Example: Facility is included in avoided costs of future transmission investment

Line name	kV	RatingMVA	case	Flow10	Flow20	Flowproj	
Forest - Valley 161kV	161kV	335	w/o LRTP	324	331	338	without LRTP, future upgrade is needed
			w/ LRTP	315	322	329	with LRTP the overload is resolved

- Includes replacement of existing facilities due to age and condition that would not be required because the LRTP projects use existing ROW of aging facilities

C. Avoided Transmission Investment

Re-use of existing ROW for LRTP projects offsets the costs of age and condition replacement of aging facilities

- The LRTP Tranche 1 portfolio of projects potentially use 836 miles of existing facilities where age and condition of the facilities is expected to require replacement of assets
- Construction of LRTP on the existing right-of-way would include replacement of existing structures and equipment that would avoid the future cost of replacing the existing facilities

C. Avoided Transmission Investment

Transmission investment is avoided by developing regional solutions vs incremental fixes

- Avoided transmission investment uses exploratory cost estimates based on type of facility improvement required
- Like in the 2011 MVP business case, an adjustment is applied to avoided reliability upgrades $\geq 345\text{kV}$ to reduce value by 50% to account for potential production cost benefits provided by the upgrades
- Capital investment for future transmission is assumed to be spread equally over the 5-year period prior to the in-service date (2040) of the avoided reliability upgrades
- The Annual Transmission Revenue Requirement was calculated to obtain the 20-year net present value discounted to 2022\$ values

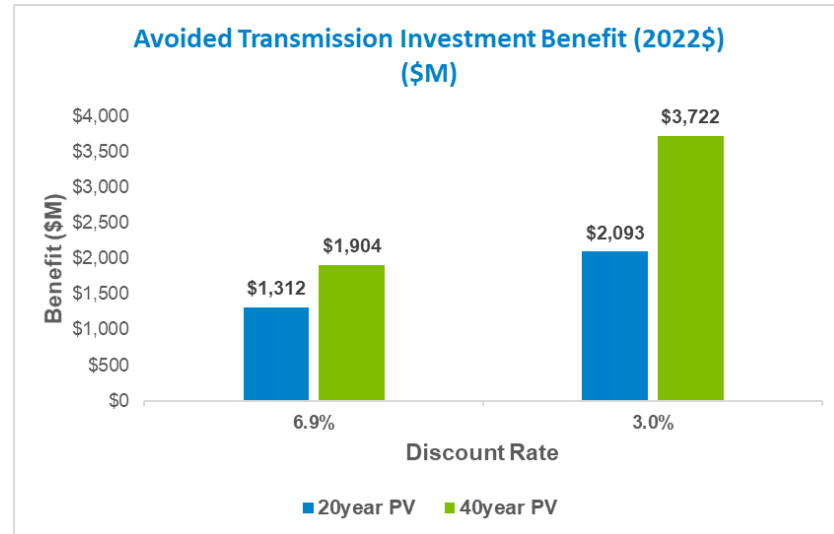
Facility Improvement Type	Unit Cost (\$M)	Quantity/Miles	Cost (\$M)*
Bustie Replacement	\$1.50	2	\$3
Transformer Replacement ≥ 345	\$5.00	4	\$20
Transformer Replacement < 345	\$3.00	5	\$15
Transmission line Replacement $\geq 345\text{kV}$ (per mile)	\$2.65	21	\$56
Transmission line Replacement $< 345\text{kV}$ (per mile)	\$1.60	1012	\$1,617
Transmission line upgrade $\geq 345\text{kV}$ (per mile)	\$0.56	230	\$64
Transmission line upgrade $< 345\text{kV}$ (per mile)	\$0.34	124	\$43
Total			\$1,819

*MISO Estimates

C. Avoided Transmission Investment

LRTP provides benefits by eliminating the need for other transmission projects

- LRTP avoids the need for transmission investment that yields 20- to 40-year present value benefits from \$1.3B to \$1.9B*



D. Reduced Resource Adequacy Requirements

The resource adequacy benefits are related to an increase in transfer capability and a reduction in the total LCR*

- As LRTP increases the transfer capability within the footprint, the increase in transfer limit is quantified
- The potential economic value unlocked by the availability of least-cost resources across the footprint due to increase in transfer capability is estimated
- A two-step process was developed to quantify the LCR reduction benefits and approximate the monetary value

D. Reduced Resource Adequacy Requirements

Step 1: Perform a transfer analysis to determine the LCR for each local resource zone (LRZ)

1. Calculate the capacity import limit (CIL) for each LRZ and case*
 - Determine the import limit (e.g., TrLim) for each LRZ and study case
 - Determine the area interchange for each LRZ and study case
2. Determine the LCR for each LRZ and case*
 - The LRR UCAP** percentages from the PY22-23 LOLE Study and the 2040 non-coincident peak load forecasts are used to set the LRR for each LRZ

Local Resource Zone	CIL (Base)	CIL (With LRTP)	Delta CIL (MW)
LRZ1	5412	6070	658
LRZ2	4188	5223	1035
LRZ3	5062	6453	1391
LRZ4	7117	7609	492
LRZ5	6131	6183	52
LRZ6	6005	6171	166
LRZ7	3367	4659	1292

D. Reduced Resource Adequacy Requirements

Step 2: Monetize the benefits identified in Step 1

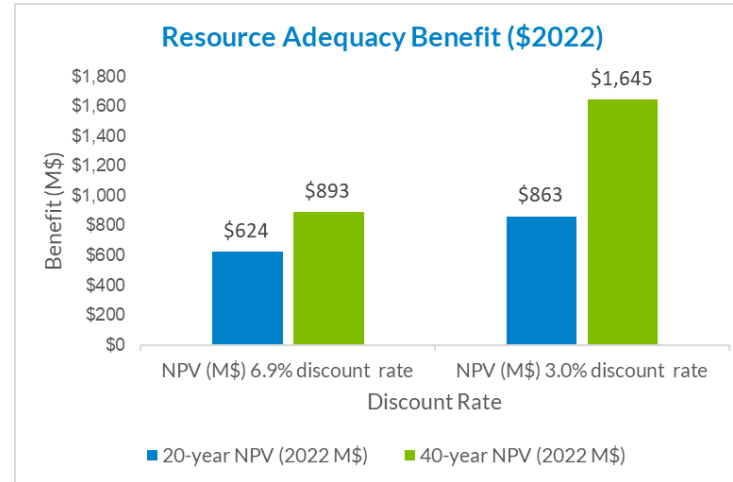
1. The 2040 unforced capacity for each LRZ is determined using forced outage rates (thermal) and ELCC* (non-thermal)
2. The excess capacity within each LRZ is calculated as follows:
 - Excess Capacity = 2040 Unforced Capacity – LCR (without LRTP)
3. The RA benefit is estimated as follows:
 - If Excess Capacity < 0 → Benefit = (CONE**) x (-Excess Capacity)
 - If Excess Capacity > 0 → Benefit = \$0/year

LRZ	1	2	3	4	5	6	7
PY22-23 CONE (\$/MW-yr)	\$91,270	\$89,490	\$86,380	\$90,300	\$97,190	\$89,040	93,770

D. Reduced Resource Adequacy Requirements

The annual economic benefits related to resource adequacy are estimated to be \$44M per year

- LRTP reduces the total LCR and yields 20- to 40-year present value benefits from \$624-\$893M*



E. Avoided Risk of Load Shedding

LRTP transmission can reduce risk of load shedding due to unplanned generation events

- Large scale unexpected loss of generation in an area presents a risk of significant load shedding
- Transmission reinforcements provided by LRTP increase transfer capability to allow load to be served from resources located in other areas
- Benefits are associated with avoided risk of load shedding focus on risks of large-scale generation loss caused by severe weather
 - Renewable production is dependent on weather conditions
 - Thermal resources have operational limitations under extreme temperature conditions
- Weather-related events occur in various scales
 - Event scenarios examine generation and load balance after loss of significant resources to determine if import capability is sufficient to cover generation deficiency
 - Risk of load shedding exists where generation deficiency cannot be covered by existing import capability
- Benefits are calculated using Value of Lost Load (VOLL) ranging from \$3500-\$23,000* /MWh

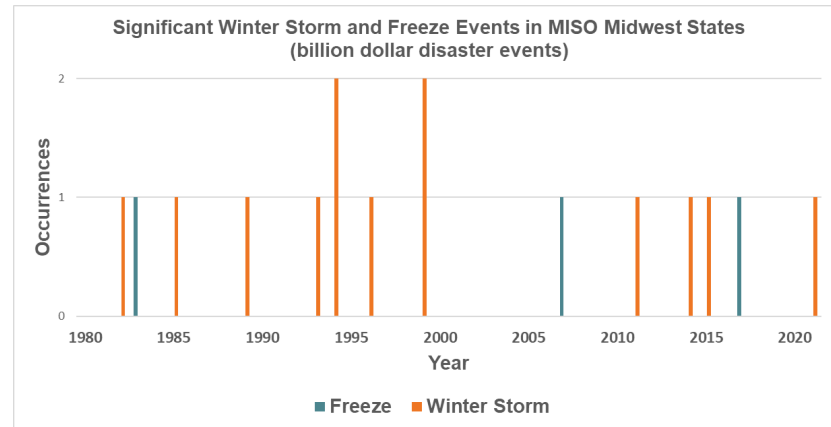
*IMM Quarterly Report: Summer 2020, https://cdn.misoenergy.org/IMM%20Quarterly%20Report_Summer%202020478028.pdf

E. Avoided Risk of Load Shedding

Analysis of risk focus on recurring severe winter weather events and variability of renewable resources

Severe winter weather events have been occurring at regular intervals over the past 40 years

More recent extreme winter events (e.g., Uri) have brought operational challenges caused by unplanned generation outages



Data Source: NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2022). <https://www.ncei.noaa.gov/billions/>, DOI: [10.25921/stkw-7w73](https://doi.org/10.25921/stkw-7w73)

E. Avoided Risk of Load Shedding

Weather conditions affect the availability of resources

- Generation capacity events have become more common in recent years with the existing resource fleet
- Weather impacts will become more significant with greater dependency on renewable resources and gas-fired dispatchable resources
- Renewable resources regularly experience periods of low output lasting several hours

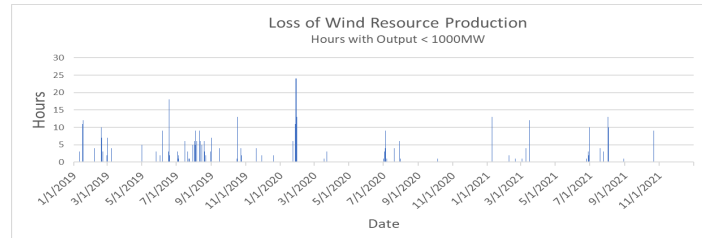
MaxGen Alerts, Warnings, and Events



Chart indicates the number of days under a max gen alert, warning or event.

Source: MISO's Response to the Reliability Imperative.

<https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative504018.pdf>



Data Source: MISO Historical Hourly Wind, <https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary&t=10&p=0&s=MarketReportPublished&sd=desc>

E. Avoided Risk of Load Shedding

LRTP transmission can reduce risk of load shedding due to unplanned loss of generation due to severe winter weather events

Area/Zonal Event Scenario

Generation Loss:
 Thermal: 40% Pmax, Wind: 90% of Pmax, Solar 50% of Pmax
 Load Forecast margin: 5% margin

Import Limit: Capacity Import Limit (CIL)

For all LRZ 1-7

$$\text{LoadLossMW} = \text{GenMW}_{\text{net}} - 1.05 * \text{LoadMW} - \text{TxFlossMW} + \text{Capacity Import Limit(MW)}$$

where $\text{GenMW}_{\text{net}} = \text{GenMW}_{\text{cap}} - \text{GenMW}_{\text{loss}}$



Regional Event Scenario

Generation Loss:
 Thermal: 50% Pmax, Wind: 90% of Pmax, Solar 50% of Pmax
 Load Forecast margin: 5% margin

Import Limit: Total Transfer Capability

Scenario 1: Source: MISO Zones 4-7 + PJM
 Sink: MISO Zones 1-3 + SPP

Scenario 2: Source: MISO Zones 1-3 + SPP
 Sink: MISO Zones 4-7

$$\text{LoadLossMW} = \text{GenMW}_{\text{net}} - 1.05 * \text{LoadMW} - \text{TxFlossMW} + \text{Total Transfer Capability(MW)}$$

where $\text{GenMW}_{\text{net}} = \text{GenMW}_{\text{cap}} - \text{GenMW}_{\text{loss}}$

E. Avoided Risk of Load Shedding

Total avoided risk of load shedding includes all winter event scenarios

Zonal

zone	GenLoss(therm)	GenLoss(wind)	GenLoss(solar)	Gen Remaining	Gen Surplus	CIL (no LRTP)	shortfall	newCIL (LRTP)	CIL diff	benefit
1	6607	6693	4612	12178	-5083	5412	-329	6070	658	
2	5369	1082	1049	8246	-3527	4188	-661	5223	1035	
3	3762	8001	3306	9529	-195	5062	-4867	6453	1391	
4	3358	2442	2065	6645	-2532	7117	-4585	7609	492	
5	2414	691	1185	5499	-2092	6131	-4039	6183	52	
6	7362	1461	2858	11873	-6680	6005	675	6171	166	166
7	6164	1714	3445	13387	-3574	3368	206	4659	1291	206
Total Avoided Load shed										372
Assumed duration										16
Total Avoided Load shed hours										5954

Regional

zone	GenLoss(th)	GenLoss(w)	GenLoss(s)	Gen Remaining	Extimp	Gen Surplus	TTC (no LRTP)	shortfall	newTTC (LRTP)	TTC diff	benefit
Lrz1-3	19672.34	15776.433	8967.45	26018.897	7500	-20239.783	7260.8	12978.983	9391	2130.2	2130.2
Lrz4-7	24123.405	6307.11	9553.2	32579.295	0	-19702.2	6192.5	13509.695	8185	1992.5	1992.5
Total Avoided Load shed											4122.7
Assumed duration											16
Total Avoided Load shed hours											65963.2
Total for all Events											71917.1

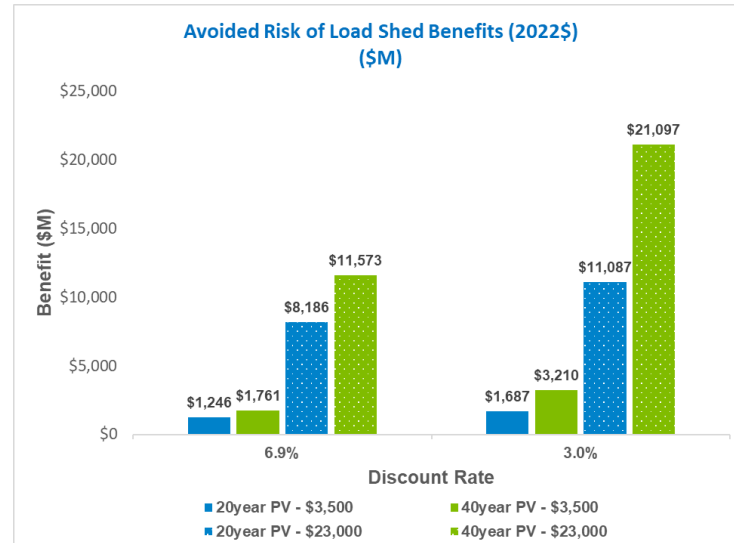
Risk of load shedding is assumed to occur every three years based on the frequency of severe winter weather events

E. Avoided Risk of Load Shedding

Value of avoided risk of load shedding is determined by applying the Value of Lost Load (VOLL)

Avoided Risk of Load Shed Value(\$) =
 VOLL * LoadLossMW * duration(hrs)
 where VOLL - Value of Lost Load: \$3500- \$23,000*

LRTP reduces risk of load shedding and provides 20-40 year net present value benefits of \$1.2B to \$11.6B**



*IMM Quarterly Report: Summer 2020, https://cdn.misoenergy.org/IMM%20Quarterly%20Report_Summer%202020478028.pdf

F. Decarbonization

MISO has developed a carbon price range to capture LRTP’s long-term benefits of reducing CO₂ emissions by enabling reliable delivery of low-cost, clean energy

- Calculate emissions reduced between LRTP Reference Case and LRTP Change Case used for the congestion and fuel cost savings benefit metric.
- Convert to metric tons.
- Using 2.5% annual inflation and discount rates below, apply range of carbon costs to calculate 20- and 40-year NPV of reduced carbon emissions.

20-Year CO₂ Emissions Reduced: 399M metric tons
 40-Year CO₂ Emissions Reduced: 677M metric tons

2022\$/metric ton	6.9% Discount Rate		3% Discount Rate	
	MN PUC (Min)	Federal (Max)	MN PUC (Min)	Federal (Max)
	\$12.55	\$47.80	\$12.55	\$47.80
20-Year Benefit (2022\$, M)	\$3,473	\$13,438	\$4,781	\$18,404
40-Year Benefit (2022\$, M)	\$4,548	\$17,364	\$7,818	\$29,498

38 Prices converted to 2022\$. Full range of carbon prices demonstrated in previous workshops. 20-year and 40-year benefits = projects’ in-service value to 2050 and 2070, respectively. Emissions data interpolated between PROMOD model years 2030, 2035, and 2040; and extrapolated post-2040.

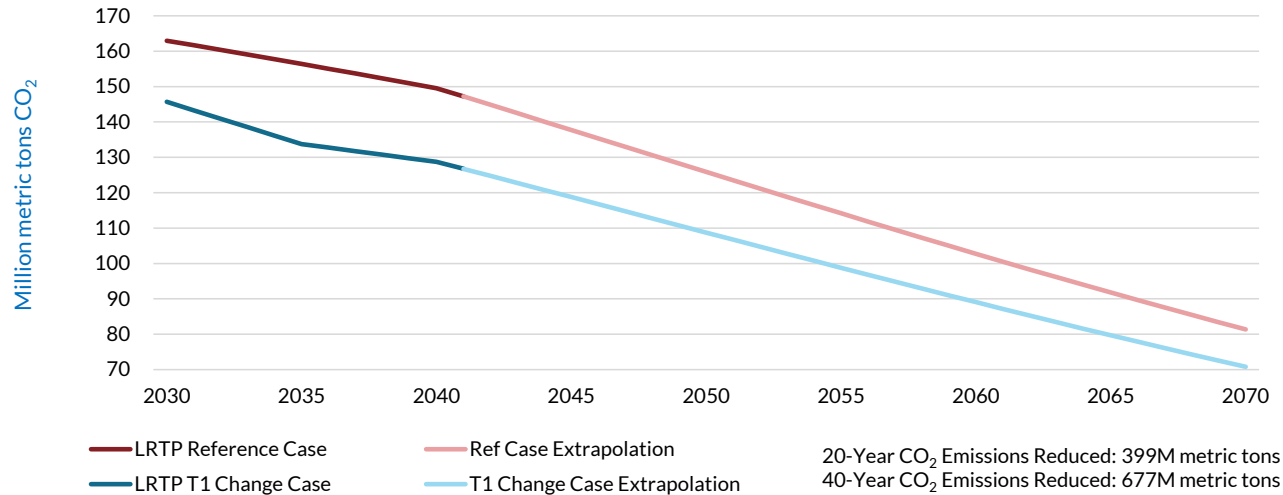
Minnesota Public Utility Commission (2022 Low)
 Federal = Average of [45Q Federal Tax Credit](#) and [Federal Social Cost of Carbon](#)



F. Decarbonization

LRTP Change Case illustrates the emissions reduced through enabled resources

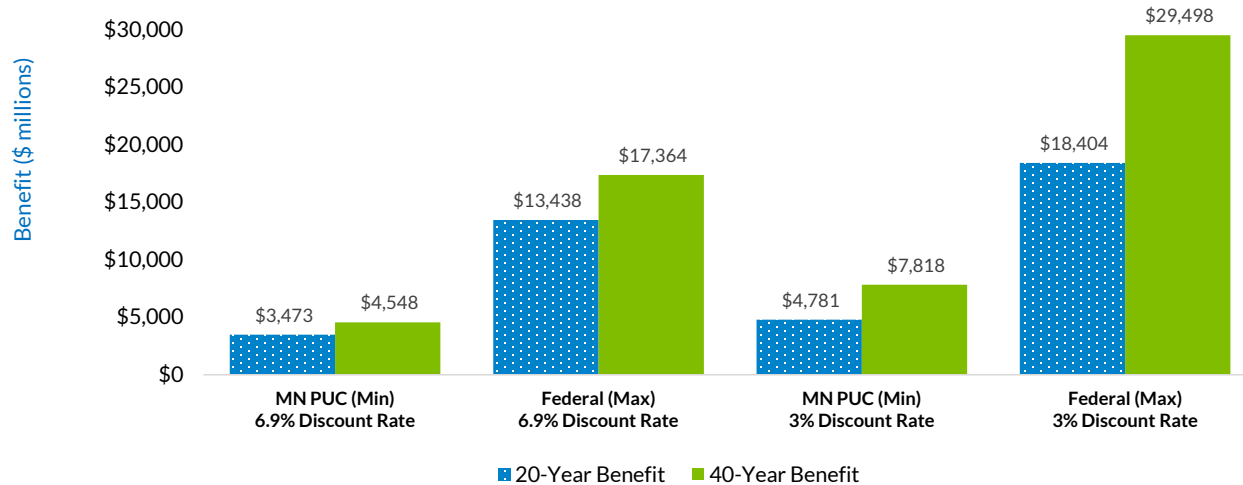
40-Year Emissions, LRTP Reference & Tranche 1 Change Cases



F. Decarbonization

With the price range considered, Decarbonization benefits range from \$3.5B to \$29.5B over 40 years of project life

Range of LRTP T1 Decarbonization 20- & 40-Year Benefits (2022\$, M)



G. Reliability issues addressed by LRTP Tranche 1

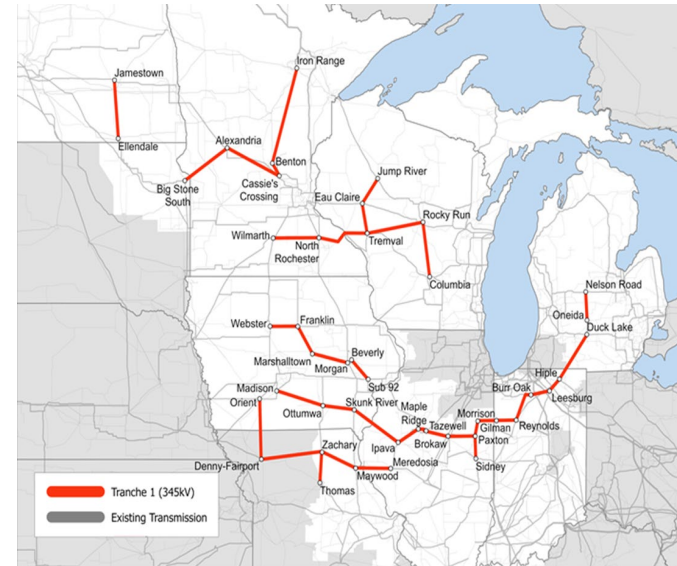
LRTP Tranche 1 portfolio allows reliable delivery of energy from future resource portfolio to serve load across the footprint

Reliability analysis was performed to assess the impact of the LRTP projects on steady state system performance

- Thermal and voltage issues were mitigated by the LRTP projects under base conditions reflecting varying load and dispatch patterns
- Additional upgrades were identified to mitigate issues resulting from the addition of LRTP projects

Transfer Analysis

- Improvements in transfer capability allows energy requirements to be met under varying dispatch patterns driven by differences in weather conditions across the Midwest subregion
- LRTP projects provides more robust interconnection to improve system stability during periods of heavy power transfers



G. Reliability issues addressed by LRTP Tranche 1

MN-Dakotas Reliability Needs Addressed

Jamestown - Ellendale 345kV, Big Stone South – Alexandria - Cassie's Crossing 345kV

- Assists in transport of energy out of Dakotas toward central MN and Twin Cities area
- Relieves issues on the 230kV system and improves connections between 345kV systems to improve long distance movement of power
- Relieves 40 elements with excessive thermal loading for N-1 contingencies and 70 elements with excessive loading for N-1-1 contingencies
- Performs better than other six alternatives removing almost all existing congestion with only minimal new congestion.

Iron Range - Benton County – Cassie's Crossing 345kV

- Provides low impedance path from Northern to Central Minnesota improving Voltage stability and transfer performance with >10% increase in Manitoba Import limit performing better with higher capacity and lower cost than the four other alternatives
- Relieves 15 elements with excessive thermal loading for N-1 contingencies and 25 elements with excessive loading for N-1-1 contingencies

G. Reliability issues addressed by LRTP Tranche 1

MN-WI Reliability Needs Addressed

Wilmarth - N. Rochester – Tremval - Eau Claire - Jump River Tremval – Rocky Run – Columbia 345kV

- Provides outlet for renewables located in Minnesota
- Congestion relief and raises stability limit by 250MW to increase transfer capability on the MN-WI interface
- Improves connectivity to serve load centers
- Relieves 39 elements with N-1 heavy loading and severe overloads in MN and WI and 96 elements for N-1-1 contingencies

G. Reliability issues addressed by LRTP Tranche 1

Central Iowa Reliability Needs Addressed

Webster-Franklin-Marshalltown-Morgan 345kV Beverly-Sub92 345kV

- Provides outlet for renewables located in IA and SW Minnesota
- Provides corridor for delivery of energy to load centers in central portions of MISO
- Addresses 21 elements with N-1 heavy thermal loading and severe overloads in Iowa and 34 elements for N-1-1 contingencies

G. Reliability issues addressed by LRTP Tranche 1

Iowa, Illinois, Indiana, Michigan Reliability Needs Addressed

Madison – Ottumwa – Skunk River – Ipava – Maple Ridge 345kV

Tazewell – Brokaw - Paxton – Gilman – Morrison – Reynolds – Hiple – Duck Lake 345kV

Paxton – Sidney 345kV

Oneida – Nelson Road 345kV

- Delivers significant increase in transfer capability to support generation deficient areas due to unexpected decrease in renewable output
- Mitigates 28 thermal overloads in Michigan, 16 thermal overload in Indiana, 19 thermal overloads in Missouri and Illinois, 14 thermal overloads in Iowa
- Provides more robust performance under large shifts in dispatch of generation across the region

G. Reliability issues addressed by LRTP Tranche 1

Missouri Reliability Needs Addressed

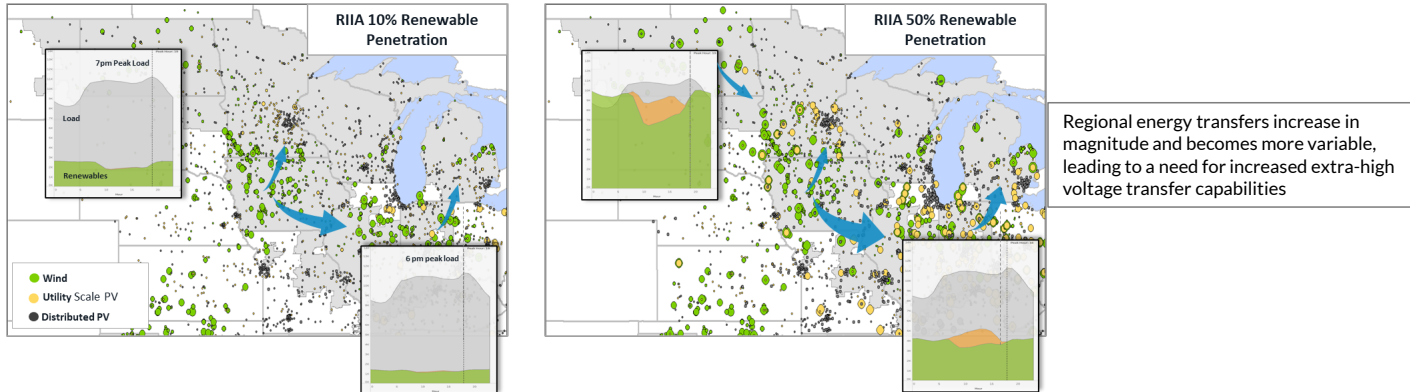
Orient – Fairport – Zachary – Maywood – Meredosia 345kV Zachary – Thomas Hill 345kV

- Provides increased transfer capability of 250MW West-to-East and 438MW MISO-to-Michigan to address voltage collapse conditions in Missouri
- Mitigates heavy loading and severe overloads on 19 elements for N-1 and N-1-1 contingencies
- Provides more robust performance under large shifts in dispatch of generation across the region addressing 14 thermal overloads

H. Other Qualitative and Indirect Benefits

Transmission investment provides other qualitative benefits that support the LRTP Tranche 1 business case

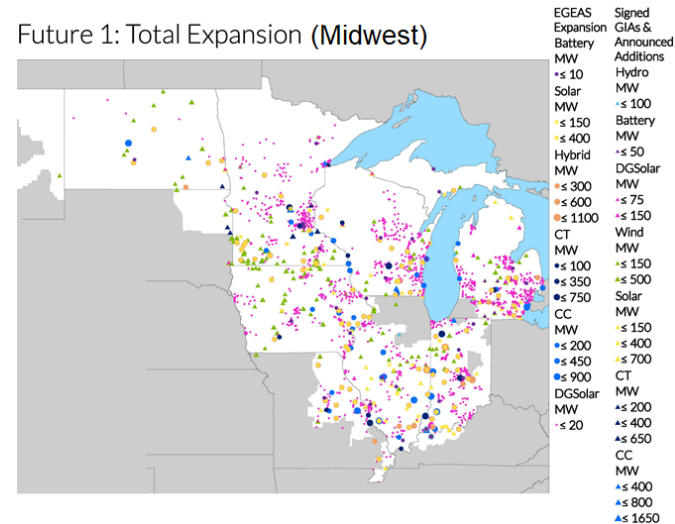
- An increasingly connected system is needed to balance generation resource variability across an increasingly heterogeneous footprint.
- Additional transmission reinforcements provided by LRTP increases the ability of the system to manage the increasing different regional flows and operational events without adverse impacts to system performance



H. Other Qualitative and Indirect Benefits

Transmission investment provides other qualitative benefits that support the LRTP Tranche 1 business case

- Increased transmission capacity better leverages the geographic and fuel diversity of the broader footprint to more effectively manage dispatch variability due to changing weather patterns



MISO Futures Report (December 2021) <https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf>

H. Other Qualitative and Indirect Benefits

Transmission investment provides other qualitative benefits that support the LRTP Tranche 1 business case

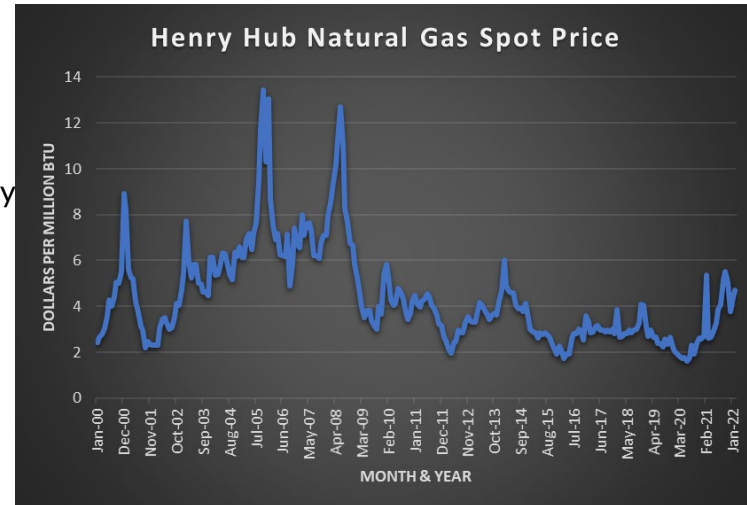
- Transmission expansion provides additional operational flexibility and allows more opportunity for planning of transmission and generation outages with less risk of operational issues or rescheduling of outages
- Transmission expansion allows better use of the transmission network and provides more flexibility to meet changing customer needs and diverse policy goals

Congestion and Fuel Savings Natural Gas Price Sensitivity

A. Congestion and Fuel Savings – Natural Gas Price Fuel Sensitivity

LRTP projects decrease system-wide impacts of natural gas volatility

- Local transmission investment cannot completely insulate electric consumers from the risks associated with fuel price volatility
- However, LRTP projects offset the risk by providing additional congestion and fuel savings benefits under high natural gas prices by enabling renewable energy
- Congestion and fuel savings benefits were analyzed through a series of production cost analyses, with higher natural gas cost assumptions



A. Congestion and Fuel Savings – Natural Gas Price Fuel Sensitivity

MISO Futures used for the LRTP study utilized new natural gas price forecast methodology

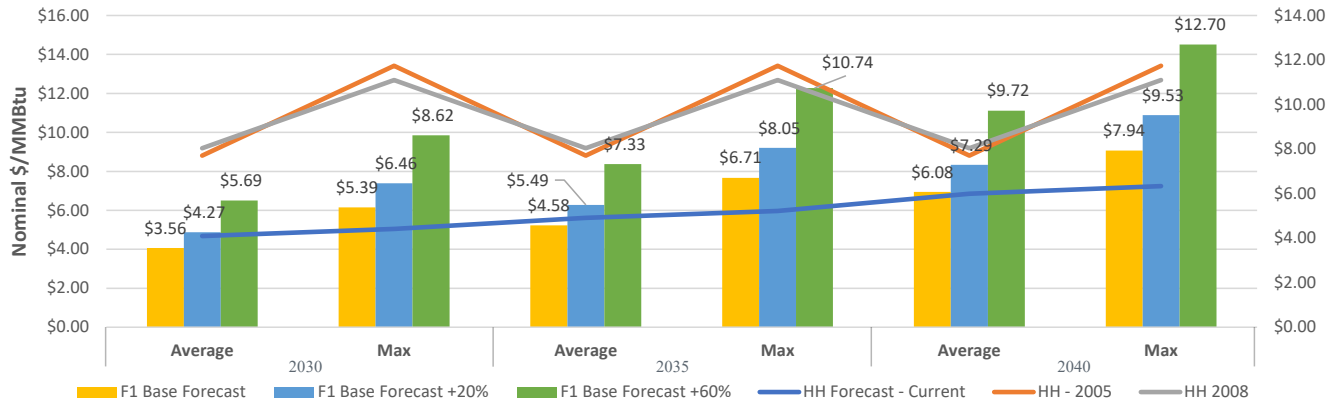
- GPCM Natural Gas Market Forecasting System was used to develop forecasts instead of locked-down Henry Hub (HH) and blend of three different forecasts
- Use on base forecast gas price in EGEAS for all Futures
- Using the same assumptions, but referencing PROMOD output, create Future-specific and area-specific gas prices for use in PROMOD models
- A range of gas prices were tested on LRTP Reference and Change Case PROMOD models



A. Congestion and Fuel Savings – Natural Gas Price Fuel Sensitivity

Future 1 Natural Gas prices were increased by 20 – 60% for sensitivity evaluation

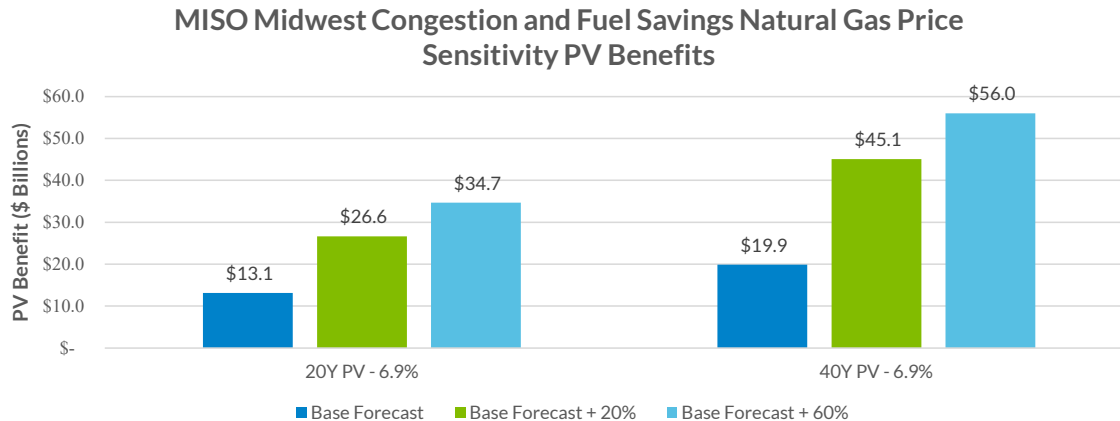
Future 1 Natural Gas Price Sensitivity \$/MMBtu Compare



- When comparing to HH prices, a 20% increase was found to facilitate the best starting point, which ensures year 2040 average price is greater than HH projected price
- A 60% increase was selected as the endpoint, to create a year 2040 value that represented HH highest sale prices historically (2005 and 2008)

A. Congestion and Fuel Savings – Natural Gas Price Fuel Sensitivity

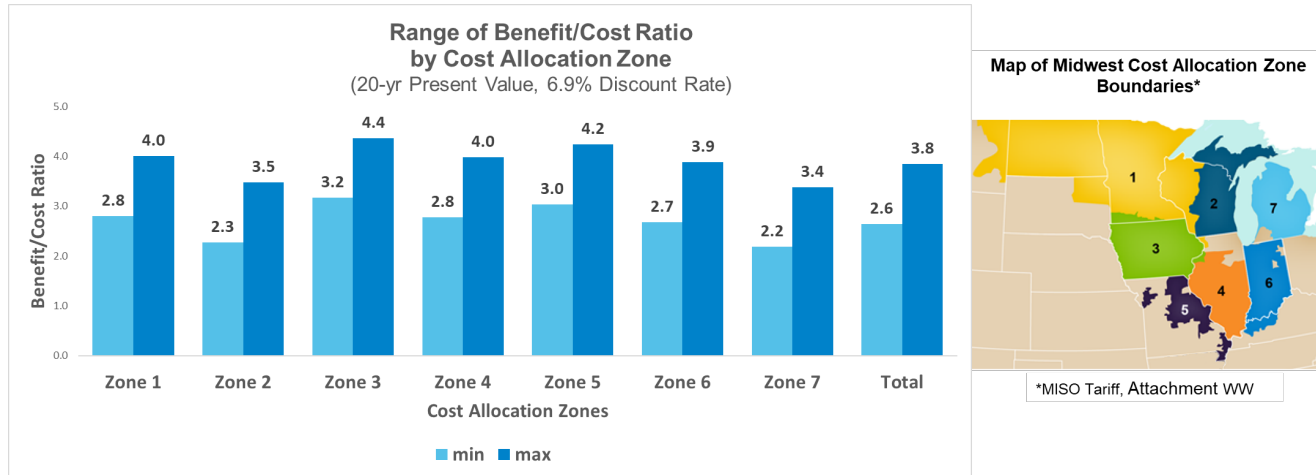
LRTP Tranche 1 transmission will provide greater congestion and fuel savings as natural gas price increases



- 20% price increase generates a \$13.4B congestion and fuel savings increase
- 60% price increase generates a \$21.5B congestion and fuel savings increase

Distribution of Benefits for Midwest Subregion

The benefits provided by the LRTP Tranche 1 Portfolio are distributed across the Midwest subregion in a manner commensurate with the costs



For the lower range of quantifiable benefits, benefit to cost ratio for the cost allocation zones is at least 2.2 where VOLL=\$3,500 and with a carbon price of \$12.55 per metric ton

Footprint Benefits (minimum)- 20 Year NPV, 6.9%, 2022\$		(\$M)							
Benefit Metric	CAZ Allocation Method	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Total
Congestion and Fuel Savings	Derived directly from PROMOD results	\$3,169	\$1,049	\$2,195	\$1,352	\$1,471	\$2,884	\$1,006	\$13,125
Avoided Capital Cost of Local Resource Investment	Based on load share ratio	\$3,481	\$2,358	\$1,864	\$1,707	\$1,351	\$3,280	\$3,460	\$17,501
Avoided Transmission Investment	Based on the zonal location of upgrade	\$278	\$283	\$201	\$305	\$125	\$45	\$74	\$1,312
Resource Adequacy Savings	Based on zonal capacity savings	\$0	\$0	\$0	\$0	\$0	\$0	\$624	\$624
Avoided Risk of Load Loss*	Based on load ratio share	\$248	\$168	\$133	\$121	\$96	\$233	\$246	\$1,246
Decarbonization**	Based on load ratio share	\$691	\$468	\$370	\$339	\$268	\$651	\$687	\$3,473
Total Benefits		\$7,867	\$4,326	\$4,763	\$3,824	\$3,311	\$7,094	\$6,096	\$37,281
Total Costs		\$2,806	\$1,901	\$1,502	\$1,376	\$1,089	\$2,644	\$2,789	\$14,107
B/C		2.8	2.3	3.2	2.8	3.0	2.7	2.2	2.6

For the upper range of quantifiable benefits, benefit to cost ratio for the cost allocation zones is at least 3.4 where VOLL=\$23,000 and with a carbon price of \$47.80 per metric ton

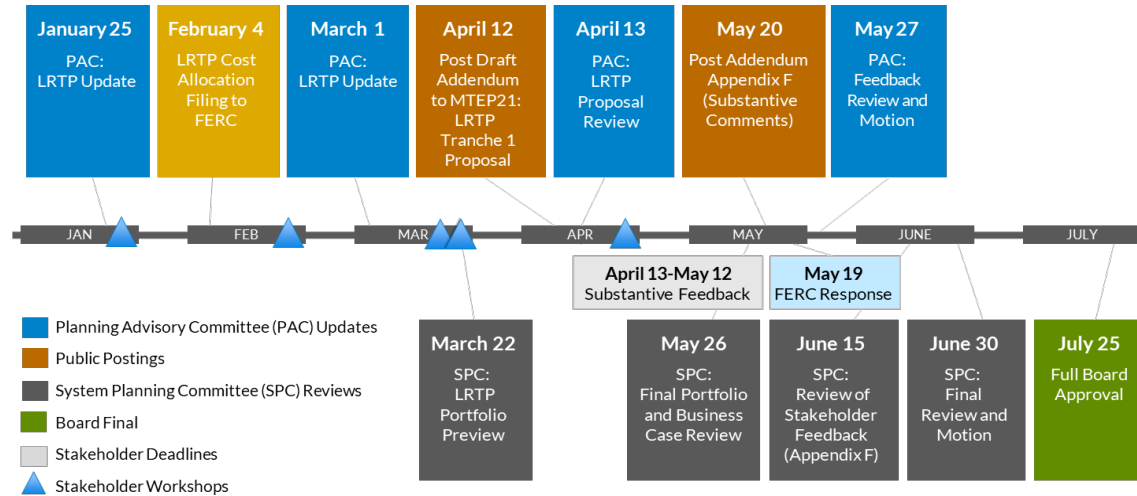
Footprint Benefits (maximum)- 20 Year NPV, 6.9%, 2022\$		(\$M)							
Benefit Metric	CAZ Allocation Method	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Total
Congestion and Fuel Savings	Derived directly from PROMOD results	\$3,169	\$1,049	\$2,195	\$1,352	\$1,471	\$2,884	\$1,006	\$13,125
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Avoided Transmission Investment	Based on the zonal location of upgrade	\$278	\$283	\$201	\$305	\$125	\$45	\$74	\$1,312
Resource Adequacy Savings	Based on zonal capacity savings	\$0	\$0	\$0	\$0	\$0	\$0	\$624	\$624
Avoided Risk of Load Loss*	Based on load ratio share	\$1,629	\$1,103	\$872	\$798	\$632	\$1,534	\$1,618	\$8,186
Decarbonization**	Based on load ratio share	\$2,673	\$1,811	\$1,431	\$1,311	\$1,037	\$2,519	\$2,656	\$13,438
Total Benefits		\$11,231	\$6,604	\$6,563	\$5,472	\$4,616	\$10,262	\$9,438	\$54,187
Total Costs		\$2,806	\$1,901	\$1,502	\$1,376	\$1,089	\$2,644	\$2,789	\$14,107
B/C		4.0	3.5	4.4	4.0	4.2	3.9	3.4	3.8

Conclusion

The LRTP Tranche 1 portfolio provides a regional transmission solution to addressing future energy needs

- For a capital investment of \$10.3B, the LRTP portfolio provides \$37.0B in financially quantifiable benefits over 20 years
- LRTP transmission projects enhance system performance to maintain reliable operation in the future with more variability and uncertainty in energy supply
- The LRTP Tranche 1 portfolio reflects a cost-effective set of solutions that enable delivery of energy to support future energy requirements of the MISO customers
- The LRTP Tranche 1 portfolio provides economic and reliability benefits that exceed the cost of the investment and are broadly distributed across the MISO Midwest subregion

The timeline for approval of Tranche 1 is targeted for July 25



STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
CONSUMERS ENERGY COMPANY for
 Ex Parte Approval of Certain Amendments to
 Rate GPD.

Case No. U-21859

PROOF OF SERVICE

On the date below, an electronic copy of **Rebuttal Testimony and Exhibit of Caroline Palmer on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (MEC-24)** was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

TROPOSPHERE LEGAL, PLC
Counsel for MNSC

Date: July 9, 2025

By: _____
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