# LRTP Tranche 2.1

## Benefits Analysis Results Review

September 25, 2024

# Purpose & Key Takeaways

## Purpose

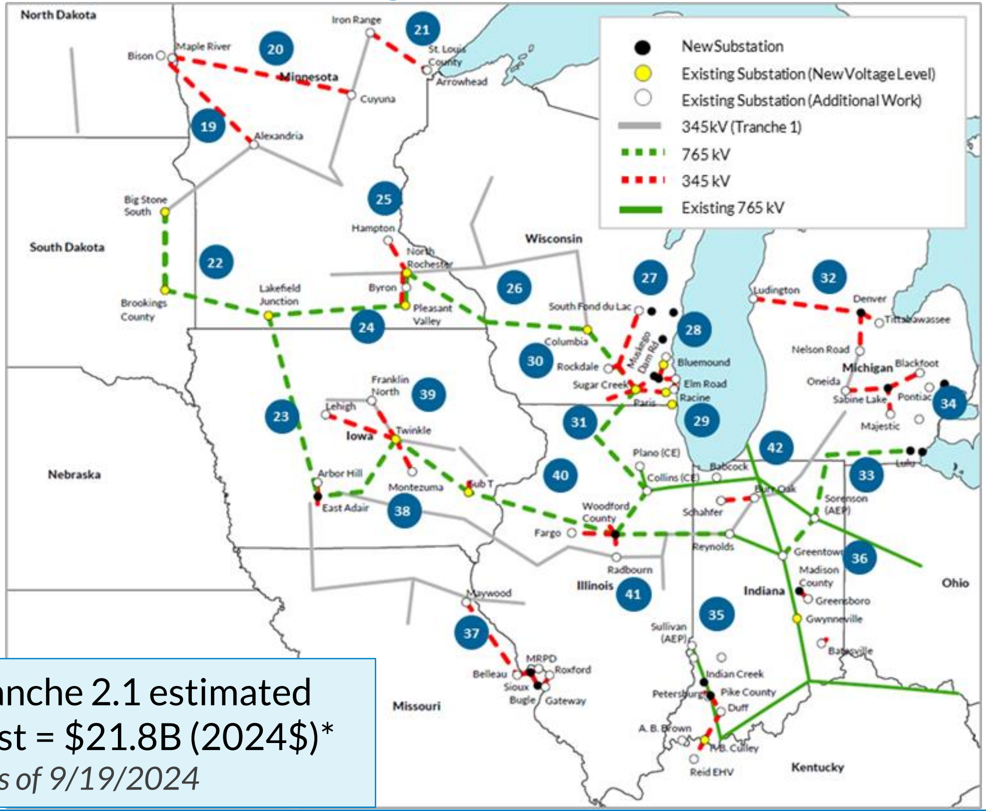
Continue discussion of LRTP Tranche 2.1 benefit analysis results

## Key Takeaways

- Updated $21.8B portfolio costs reflect further refinements of the estimated facility costs
- F2A benefits also refined further with updates to mitigation of reliability issues, avoided capacity costs, capacity savings from reduced losses, and avoided transmission metrics
- Benefits reflect a broad set of metrics to show a regional benefit-to-cost ratio of at least 1.8 over the first 20 years of transmission in-service life using Future 2A
- Future 1A results also show a B/C ratio greater than 1.0 for the Midwest Subregion

# The Tranche 2.1 portfolio enables the resources required to maintain reliability and serve energy needs for the MISO system while providing benefits in excess of its cost

- Selected projects represent least-regrets solutions to ensure reliable and efficient energy delivery to MISO Midwest customers



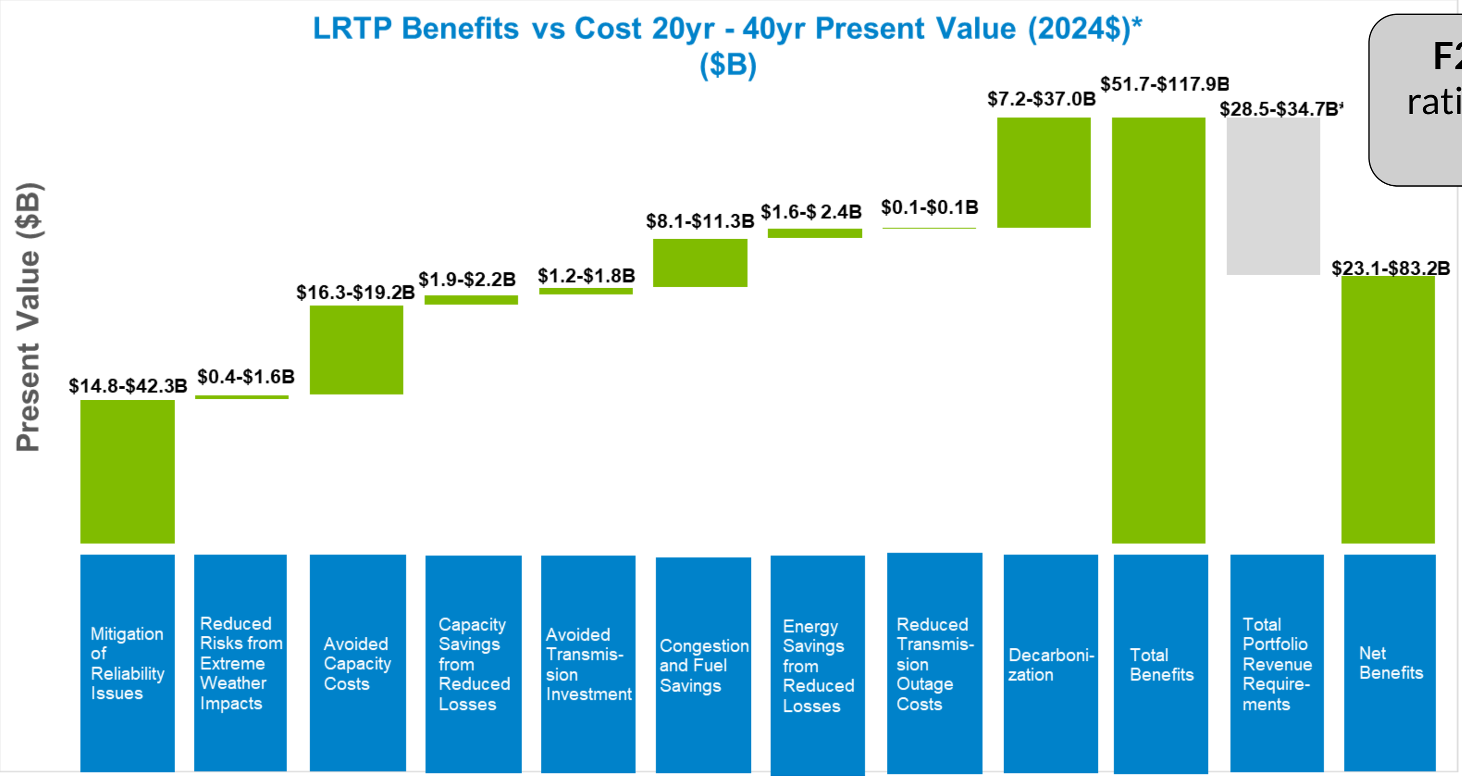

LRTP Tranche 2.1 estimated project cost = $21.8B (2024$)*

*as of 9/19/2024*



MISO

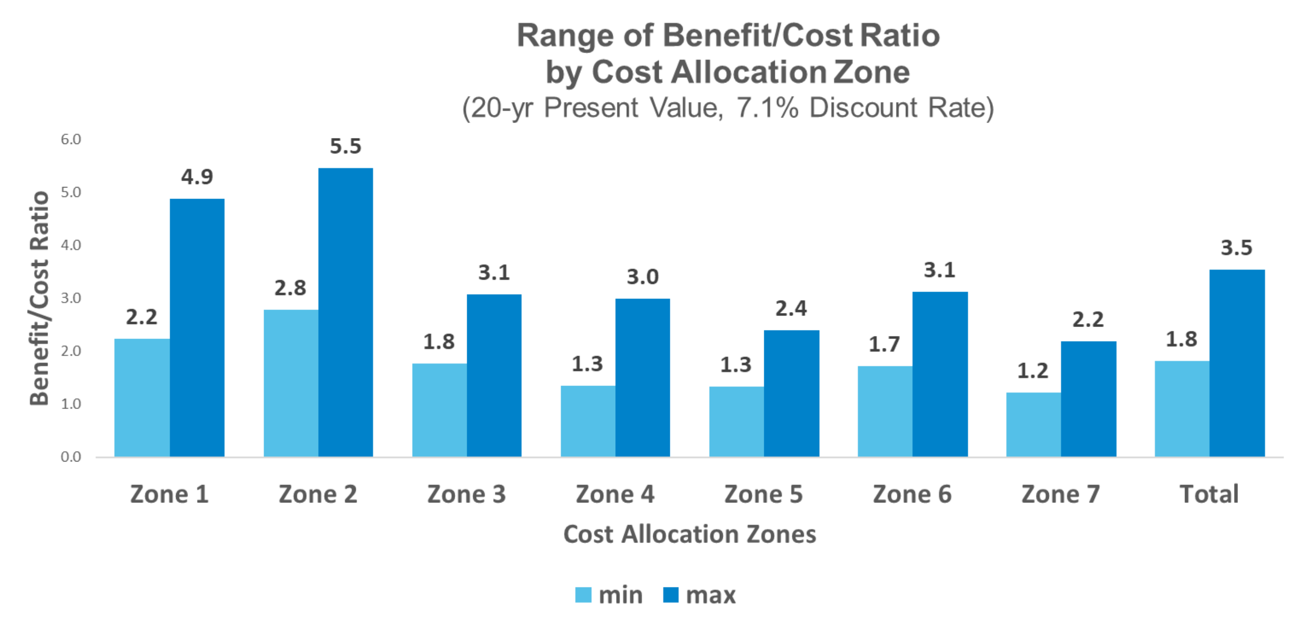
# Tranche 2.1 portfolio under Future 2A provides a regional benefit-to-cost ratio of at least 1.8 capturing multiple types of reliability, economic and policy value



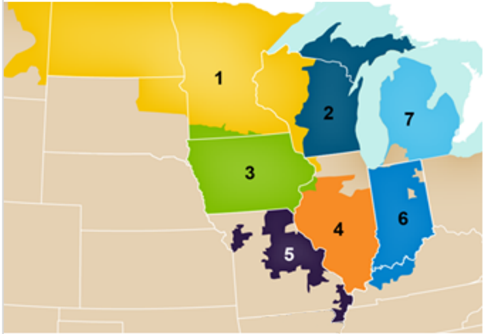

**F2A** Total B/C ratio ranges from **1.8 to 3.5**

*Estimated costs as of 9/19/2024. Assumes 7.1% discount rate. *Link to LRTP Tranche 2.1 metrics* [whitepaper](whitepaper).

# Tranche 2.1 portfolio benefits exceed costs and are broadly distributed across the Midwest Subregion with each zone showing a B/C ratio > 1.0* under Future 2A




**Map of Midwest Cost Allocation Zone Boundaries***




*MISO Tariff, Attachment WW

* *See appendix pg. 34-37 for more detailed information on cost allocation zone benefits. Link to LRTP Tranche 2.1 metrics whitepaper.*

# Avoided Capacity Costs

# Avoided Capacity Costs reflect more efficient buildout of resources where transmission expansion improves access to resources across the footprint

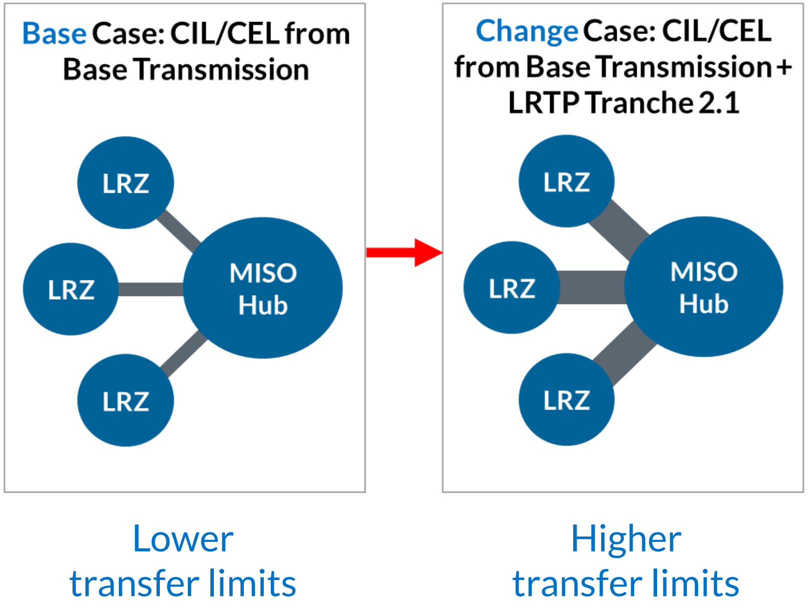
- Transmission constraints limit the ability for regional resources to meet the capacity needs of the MISO region
- LRTP projects increase the capacity of transmission system and allow the capacity needs of the MISO region to be met with fewer resources
  - This is calculated by measuring zonal transmission limits with and without LRTP
- Benefits examine the difference in the additional capacity reserves that are needed to maintain 0.1d/yr LOLE with and without LRTP
- Incremental EGEAS resource expansion is performed with the additional capacity reserves to determine the capital costs for resource additions

# The Avoided Capacity Cost (ACC) metric reflects the capital cost savings from the increase in transmission capability provided by LRTP, enabling access to resources over the wider MISO footprint

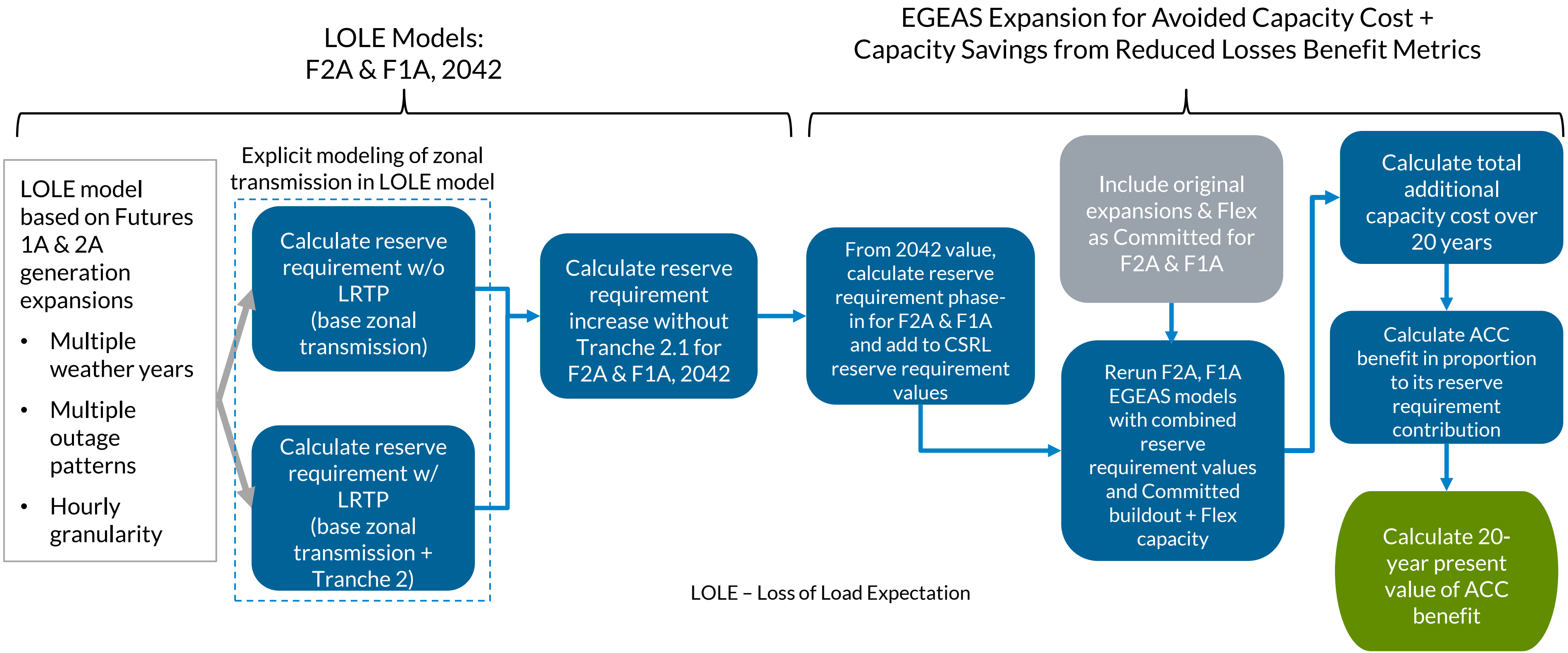
- This benefit leverages LOLE modeling and incorporates a simplified representation of transmission constraints

- The benefit assesses the change in loss of load expectation (LOLE) to determine the adjustment in planning reserves to meet the LOLE target with and without the LRTP portfolio

- Change in planning reserve is applied to the base PRM value used in EGEAS to determine the amount and composition of the additional resources that would be needed in the absence of LRTP



# LOLE modeling will be used to determine the adjustment in the capacity required to meet the LOLE target with and without the LRTP portfolio




Base zonal and (Base zonal + Tranche 2.1) transmission was determined using a transfer analysis.

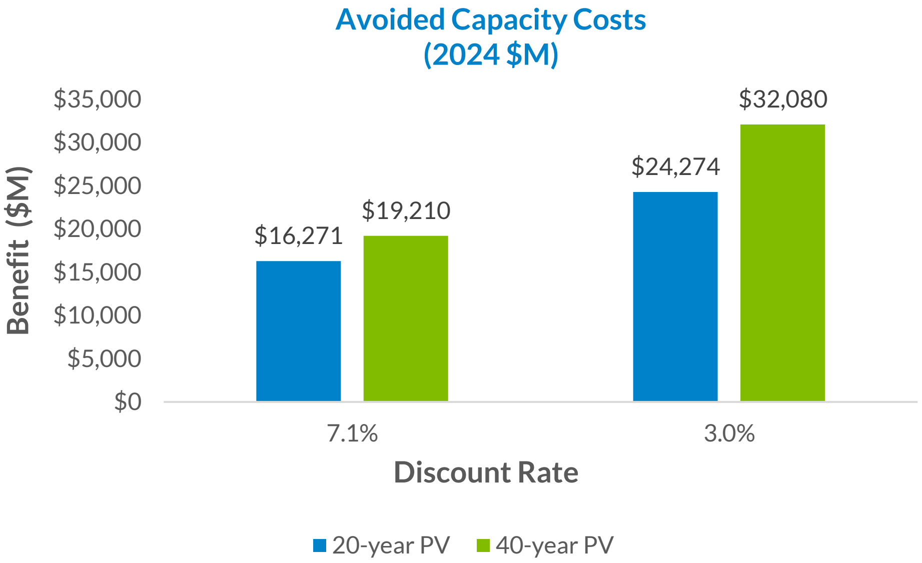
# PRM value will be assumed to increase over the last 10 years of the study period

- PRM is assumed constant until Tranche 2.1 projects come into service in 2032, and then increases as the expansions proceed to 2042
- Difference in PRM between the base and Tranche 2.1 cases will be added to the original 18% PRM assumption
- PRM change from base to Tranche 2.1 case calculated for 2042
- PRM change assumed to increase linearly from 2032 until 2042
- The total capacity addition is split into benefit components by the percent contribution to the additional PRM value

| Combined ACC+CSRL PRM Phase-In | | | | | Avoided Capacity Costs (ACC) | | Capacity Savings from Reduced Losses (CSRL) |
|---|---|---|---|---|---|---|---|
| | | | Total | Total | | | |
| | | | PRM Enforced (%) | PRM Addition (%) | % Contribution to Total Additional PRM, 2042: | | |
| Year | 1 | 2023 | 18.05 | | 90% | | 10% |
| | 2 | 2024 | 18.05 | | | | |
| | 3 | 2025 | 18.05 | | | | |
| | 4 | 2026 | 18.05 | | ACC | | CSRL |
| | 5 | 2027 | 18.05 | | 2032-2041 values extrapolated | | Interim values interpolated |
| | 6 | 2028 | 18.05 | | from 2042 value | | from 2032, 2042 values |
| | 7 | 2029 | 18.05 | | | | |
| | 8 | 2030 | 18.05 | | Additional PRM (%) from CIL/CEL: | | Additional PRM (%) from reduced losses: |
| | 9 | 2031 | 18.05 | | | | |
| Year | 10 | 2032 | 19.66 | 1.61 | 0.80 | 2032 | 0.81 |
| | 11 | 2033 | 20.47 | 2.42 | 1.59 | 2033 | 0.83 |
| | 12 | 2034 | 21.28 | 3.23 | 2.39 | 2034 | 0.84 |
| | 13 | 2035 | 22.10 | 4.05 | 3.19 | 2035 | 0.86 |
| | 14 | 2036 | 22.91 | 4.86 | 3.98 | 2036 | 0.88 |
| | 15 | 2037 | 23.72 | 5.67 | 4.78 | 2037 | 0.90 |
| | 16 | 2038 | 24.54 | 6.49 | 5.57 | 2038 | 0.91 |
| | 17 | 2039 | 25.35 | 7.30 | 6.37 | 2039 | 0.93 |
| | 18 | 2040 | 26.17 | 8.12 | 7.17 | 2040 | 0.95 |
| | 19 | 2041 | 26.98 | 8.93 | 7.96 | 2041 | 0.97 |
| Year | 20 | 2042 | 27.81 | 9.76 | 8.76 | 2042 | 1 |

# Tranche 2.1 portfolio improves transmission capacity to provide more efficient resource investment

- LRTP Tranche 2.1 enables access to regional resources, which reduces the need additional capacity investment
- LRTP Tranche 2.1 avoids the need for 22.8GW of capacity in addition to F2A resources and provides a 20-year present value benefit of $16.3B*




* Discount rate of 7.1%

# Mitigation of Reliability Issues

# Reliability benefits reflect the value of mitigating risk of unserved load with transmission investment

- System performance requirements are established by planning criteria and industry standards to reduce risk of unserved load (e. g., planning standards, storm hardening criteria)
- Specific thermal and voltage criteria are defined for acceptable system performance
- Failure to mitigate violations of thermal/voltage criteria can result in unserved load
- Transmission solutions alleviate thermal/and voltage violations to mitigate risk of unserved load
- Reliability benefits can be quantified using the avoided risk of unserved load that reflects the value of uninterrupted service for customers

# Reliability benefits monetize the avoided risk of unserved load that would otherwise occur if system performance criteria are not met

- Reliability benefits are provided by addressing thermal violations
  - Contingency violations must be addressed proactively – cannot rely on post-contingent action to fix an issue
  - Benefit analysis focuses on a narrow set of conditions:
    1. Constraints caused by a single element (NERC Category P1, P2, P7) contingency[1]
    2. Mitigated by the LRTP portfolio, and
    3. That cannot be mitigated by generation redispatch
- Reliability benefit can be measured by examining the amount of load shedding otherwise required to alleviate violations
  - The amount of load shedding that is avoided by LRTP projects is the reliability benefit of mitigating reliability issues
  - VOLL is established as a market price of energy that customers are willing to pay to avoid interruption of load and used to monetize benefit

*Benefit = LoadShedMW x hrs x VOLL*

*where hrs = # risk hours represented by study case*

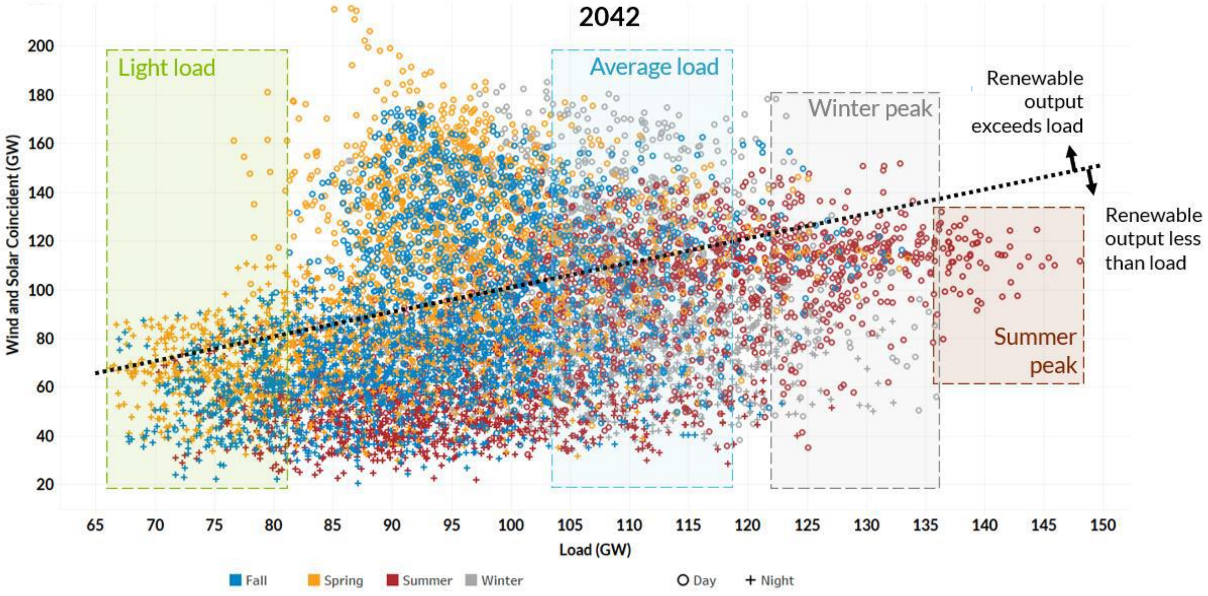
*VOLL = range($3,500/MWh[2], $10,000/MWh[3])*

[1]NERC TPL-001-5.1 Transmission Planning Standard ,
[2]Current VOLL
[3]Continued Reforms to Improve Scarcity Pricing and Price Formation (MSC-2019-1)

# Study scenarios represent conditions over multiple hours of the year and are used to examine and quantify load shedding risk

*Hours of unserved load are determined by examining the dispatch and load distribution associated with each model scenario*

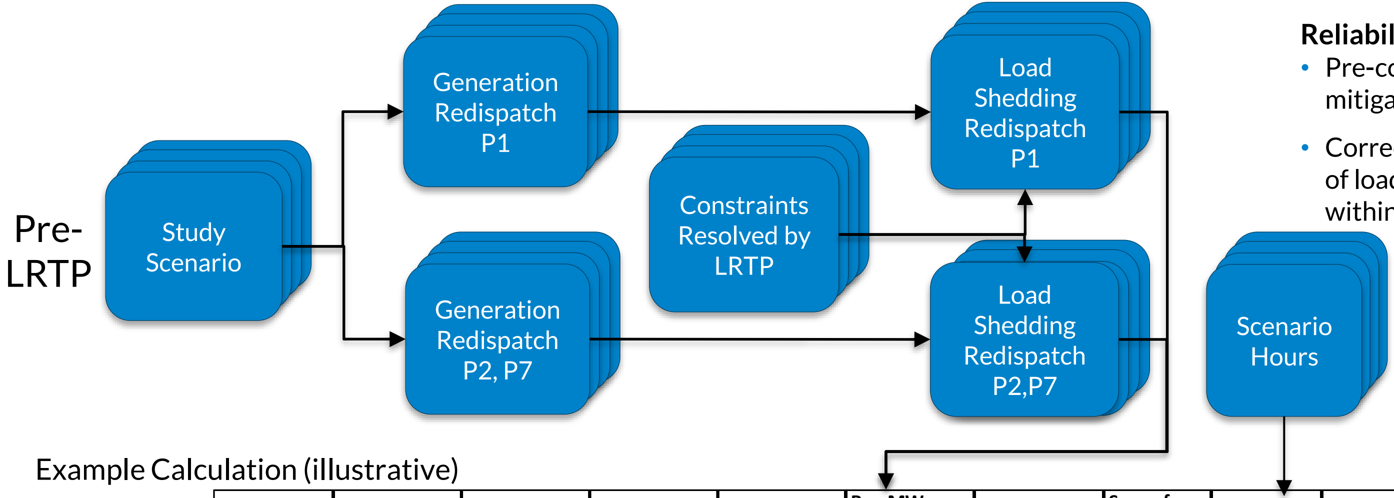
- Model scenarios represent a subset of annual conditions
- Load shedding risk hours correspond to hours represented by the study scenario in the annual load distribution



# A two-step process is used to perform reliability re-dispatch to mitigate issues and identify residual overloading that would require load shedding

- Generation re-dispatch
  - Applied to NERC Category P1, P2, and P7 contingencies as pre-contingent mitigation
  - Used primarily to recognize that renewable availability varies over the hours represented by the study model
  - Dispatch scenarios represent hours where renewable availability is higher or lower than reflected in study model
    - Renewable resources allowed to dispatch up for hours with excess availability
    - Renewables resources are limited to dispatch downward for hours without excess availability
  - Thermal resources participate in NERC Category P1 scenarios for consistency with production cost simulations (limitations are applied in Category P2 and P7)
- Load re-dispatch
  - Load re-dispatch is applied only to constraints that remain after generation re-dispatch
  - Used to calculate the amount of load reduction required to mitigate unresolved constraints
  - Corrective load shedding is applied in analysis to optimize load shedding for each contingency
  - Avoided load shedding for each scenario is the sum of the maximum amount of load reduction at each bus for all contingencies

# Generation re-dispatch and load re-dispatch are used to identify load shedding risk




**Reliability dispatch is used for:**

- Pre-contingent generation redispatch for mitigation of thermal issues
- Corrective load dispatch to determine amount of load reduction that would maintain loading within limits

Example Calculation (illustrative)

| Model | Redispatch Scenario | Monitored | Contingency | Pre-overload % | Pre-MW Relief Required | Buses | Sum of Max Load Shed MW | Scenario Hours | MWh Benefit |
|---|---|---|---|---|---|---|---|---|---|
| 2032sum | up/down | St A- St B | P1_Ctg1 | 115% | 16MW | bus-a bus-b | 124 | 48 | 5,952 |
| 2032avg | up/down | St C - St D | P1_Ctg2 | 124% | 32MW | bus-c bus-d bus-e | 46 | 420 | 19,320 |
| 2032avg | down-only | St E - St F | P1_Ctg3 | 107% | 20MW | bus-f bus-g bus-h bus-i | 295 | 1362 | 401,790 |
| 2032avg | down-only | St G - St H | P2_Ctg4 | 109% | 18MW | | | | |
| | | | | | | | Load Shedding MWh | | 427,062 |

# Reliability benefits monetize the avoided risk of unserved load that would otherwise occur if system performance criteria are not met

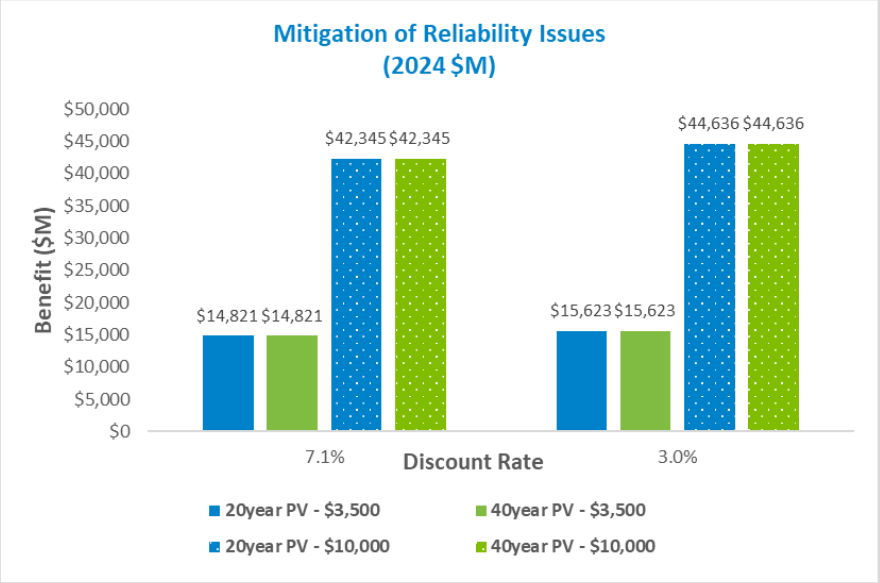
LRTP Tranche 2.1 projects address numerous thermal overloads that otherwise present a risk of unserved energy

Benefits

*Total unserved energy risk by season (GWh)*

| | *Summer* | *winter* | *average* | *light load* |
|---|---|---|---|---|
| *2032* | *449* | *58* | *2971* | *278* |
| *2042* | *149* | *80* | *400* | *115* |

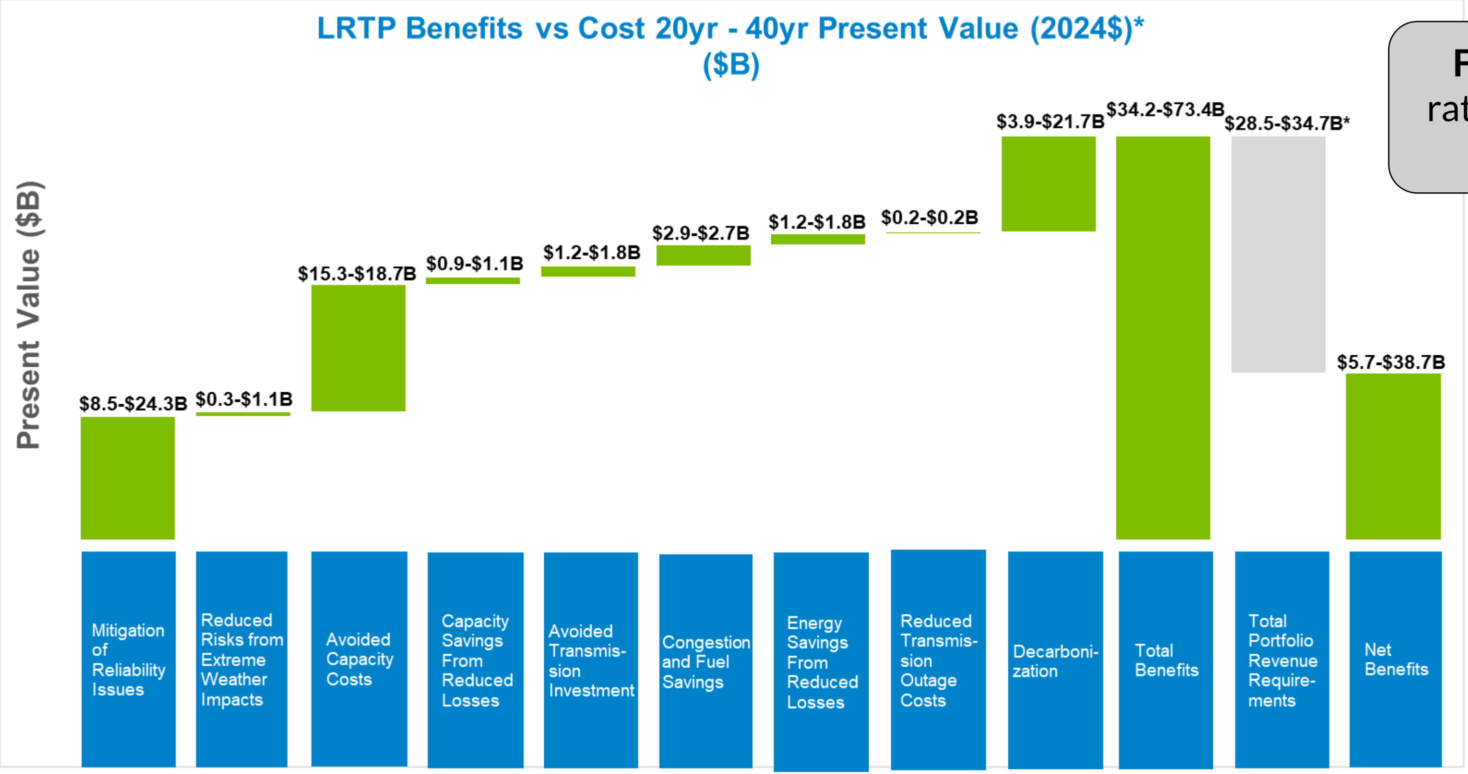
LRTP Tranche 2.1 portfolio mitigates risk of unserved load from transmission overloading and yields 20-year present value benefits of $14.8B




[2]Current VOLL
[3]Continued Reforms to Improve Scarcity Pricing and Price Formation (MSC-2019-1)

# Future F1A Benefit Analysis Results

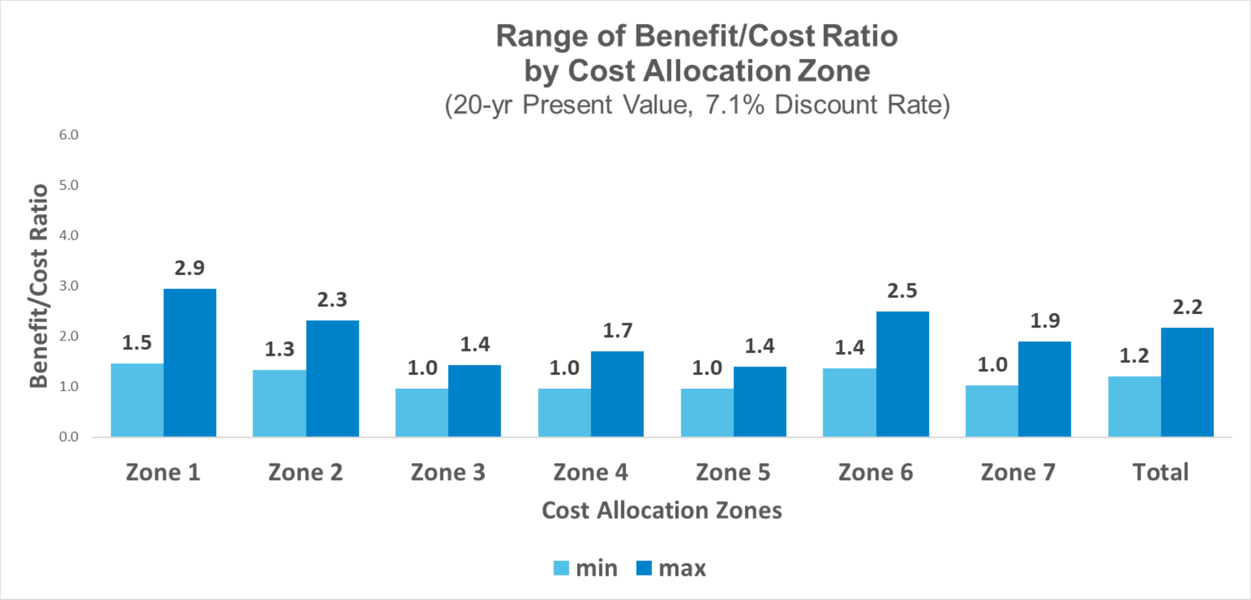
# Tranche 2.1 portfolio also shows total benefits in excess of costs under the more conservative lower bookend of F1A



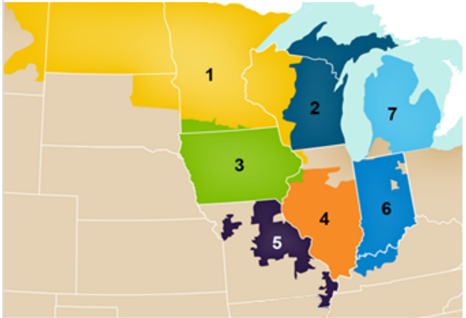

**F1A** Total B/C ratio ranges from **1.2 to 2.2**

*Estimated costs as of 9/1/2024. Assumes 7.1% discount rate. *Link to LRTP Tranche 2.1 metrics whitepaper*.

# Under F1A the Tranche 2.1 portfolio continues to show benefits are broadly distributed across the Midwest Subregion with each zone showing at least a 1.0 B/C ratio




**Map of Midwest Cost Allocation Zone Boundaries***



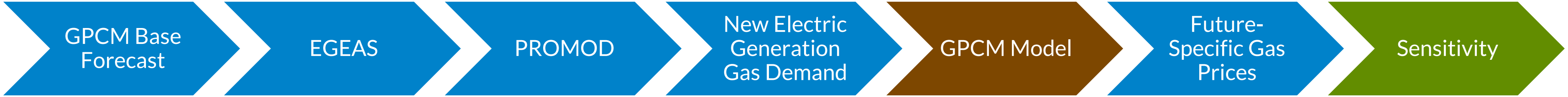

*MISO Tariff, Attachment WW

*Link to LRTP Tranche 2.1 metrics whitepaper.*

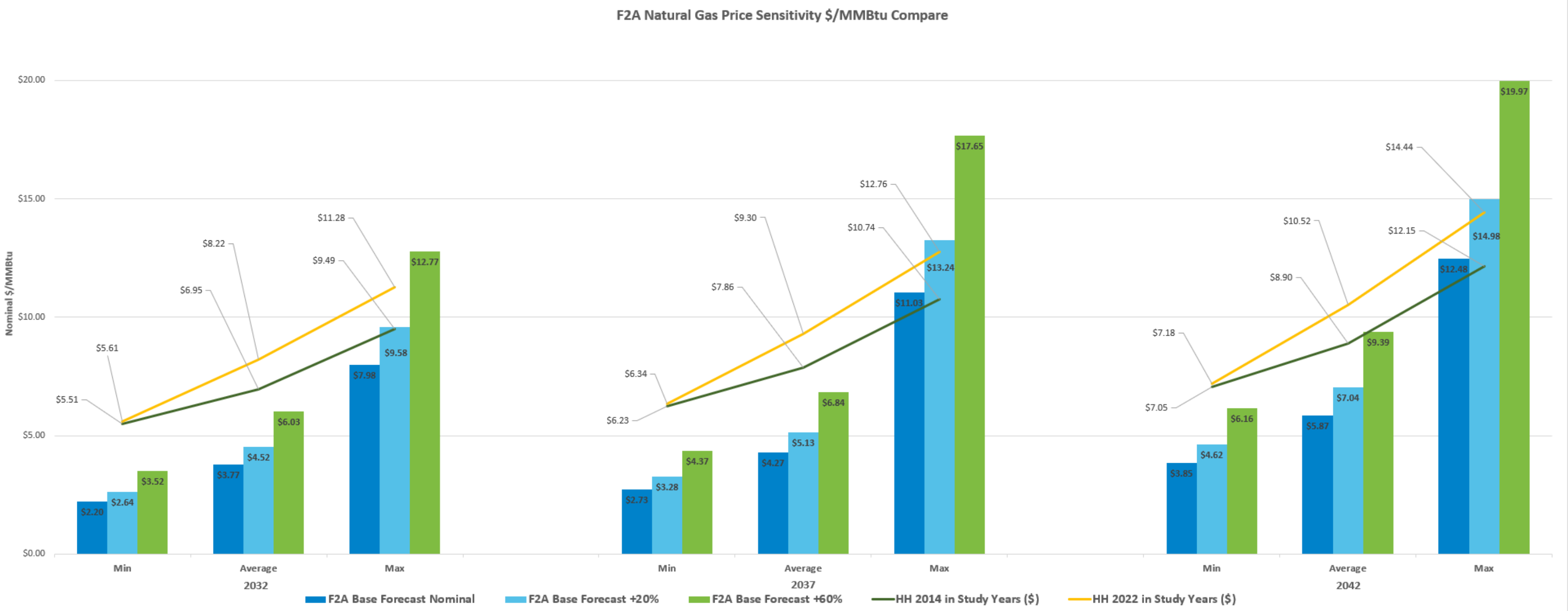
# Congestion and Fuel Savings Natural Gas Price Sensitivity

# MISO Futures used for the LRTP T2.1 study utilized new natural gas price forecast methodology

- Gas Pipeline Competition Model (GPCM) 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 tested on LRTP Reference and Change Case PROMOD models was developed by evaluating historical HH gas prices spanning a 10-year period between 2012-2022

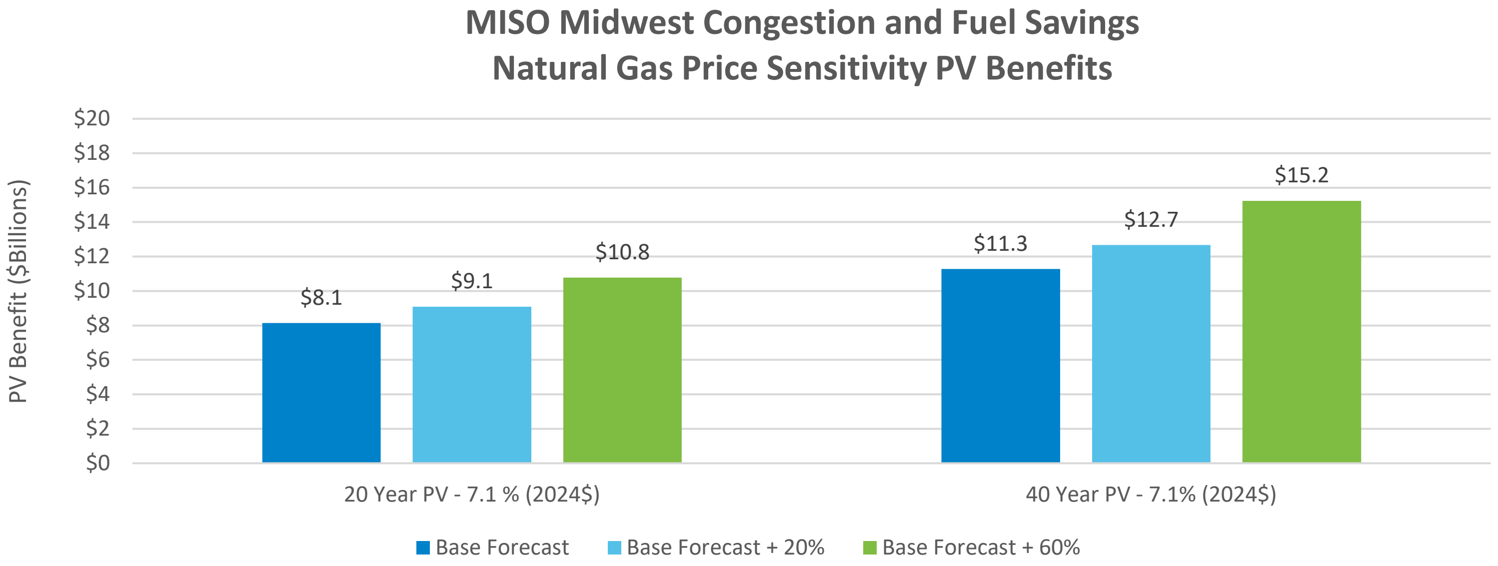


# Future 2A Natural Gas prices were increased by 20 – 60% for sensitivity evaluation




- When comparing to HH prices a 20% increase was found to facilitate a starting point, which ensures year 2042 average price is on par with historical averages without 2042 max price overly exceeding historical high prices.
- When comparing HH prices a 60% increase was found to facilitate an end point, to create a year 2042 price that represented HH sale price that did not exceed historical highs (2005 and 2008) but instead represented price peaks between years 2012 to 2022

# LRTP T2.1 transmission will provide greater congestion and fuel savings as natural gas price increases




- 20% gas price increase generates a $9.1B congestion and fuel savings, approximately $1B increase in savings
- 60% gas price increase generates a $10.8B congestion and fuel savings increase, approximately $2.6B increase in savings

# Economic Development Impact from Transmission

# Tranche 2.1 transmission investments will deliver significant economic development benefits to local economies in the MISO region

- Long-run impacts on economic growth are difficult to quantify, but short-run impacts on employment and economic output can be quantified
- MISO literature review on the impacts of transmission investment finds that every $1 million in transmission investment powers:
  - 1 – 3 direct local jobs
  - 2 – 6 total local jobs
  - $0.2 – $1.1 million in total local economic output
- Ranges chosen to cover roughly 90% of study estimates found in literature review
- Direct jobs are high-quality jobs, with wages estimated to be about 30% higher than a typical worker's wages

*Literature Review Sources:* The Brattle Group Literature Review (2011), London Economics International (2018, 2021), Loomis (2012), Strategic Economics Group (2013), Swenson (2018), Strategic Economic Research (2013, 2022a, 2022b, 2023), University of Minnesota Duluth Bureau of Business and Economic Research (2024), West Monroe (2024)

# Tranche 2.1 transmission investments are estimated to power between 22,000 and 65,000 direct jobs and between $4 and $24 billion in total economic output

| | Tranche 2.1 Investment ($Mns) | Direct Local Jobs | | Total Local Jobs | | Local Investment/Total Economic Output ($Mns) | |
|---|---|---|---|---|---|---|---|
| ***Central*** | | *Low Estimate* | *High Estimate* | *Low Estimate* | *High Estimate* | *Low Estimate* | *High Estimate* |
| MO | $872 | 872 | 2,616 | 1,744 | 5,231 | $ 174 | $ 959 |
| IL | $2,886 | 2,886 | 8,659 | 5,772 | 17,317 | $ 577 | $ 3,175 |
| IN | $2,378 | 2,378 | 7,135 | 4,757 | 14,270 | $ 476 | $ 2,616 |
| KY | $77 | 77 | 230 | 153 | 459 | $ 15 | $ 84 |
| ***East*** | | | | | | | |
| MI | $2,672 | 2,672 | 8,015 | 5,344 | 16,031 | $ 534 | $ 2,939 |
| ***West*** | | | | | | | |
| IA | $3,606 | 3,606 | 10,817 | 7,212 | 21,635 | $ 721 | $ 3,966 |
| MN | $4,342 | 4,342 | 13,026 | 8,684 | 26,051 | $ 868 | $ 4,776 |
| ND | $188 | 188 | 564 | 376 | 1,129 | $ 38 | $ 207 |
| SD | $724 | 724 | 2,171 | 1,447 | 4,341 | $ 145 | $ 796 |
| WI | $4,086 | 4,086 | 12,257 | 8,171 | 24,514 | $ 817 | $ 4,494 |
| **Total** | $21,830 | 21,830 | 65,489 | 43,659 | 130,978 | $ 4,366 | $ 24,013 |

# Questions?

LRTP Website

[Long Range Transmission Planning (misoenergy.org)]

LRTP Help Center

[Help Center (misoenergy.org)]

# Appendix

# MISO's approach to the Tranche 2.1 business case analysis builds off the Tranche 1 benefit metrics*

| Benefit Metric | Description |
|---|---|
| 1) Mitigation of reliability issues | Value of alleviating reliability issues that unresolved introduce a risk of unserved load |
| 2) Reduced risks from extreme weather events | Increases grid resilience and decreases the probability of major service interruptions |
| 3) Avoided capacity costs | Avoids capital costs for local resource builds versus regional expansions defined in Futures |
| 4) Capacity Savings from Reduced Losses | Value of reducing transmission losses during peak capacity periods |
| 5) Avoided transmission investments | Avoids the need for facility replacement due to age and condition |
| 6) Congestion and fuel savings | Enhances market efficiency and provides access to low-cost generation |
| 7) Energy Savings from Reduced Losses | Lower production costs to serve load with transmission facilities that reduce system losses |
| 8) Reduced transmission outage costs | Reduced transmission congestion during forced and planning transmission outages |
| 9) Decarbonization | Enables the economical dispatch of renewable resources to help reduce the carbon footprint |

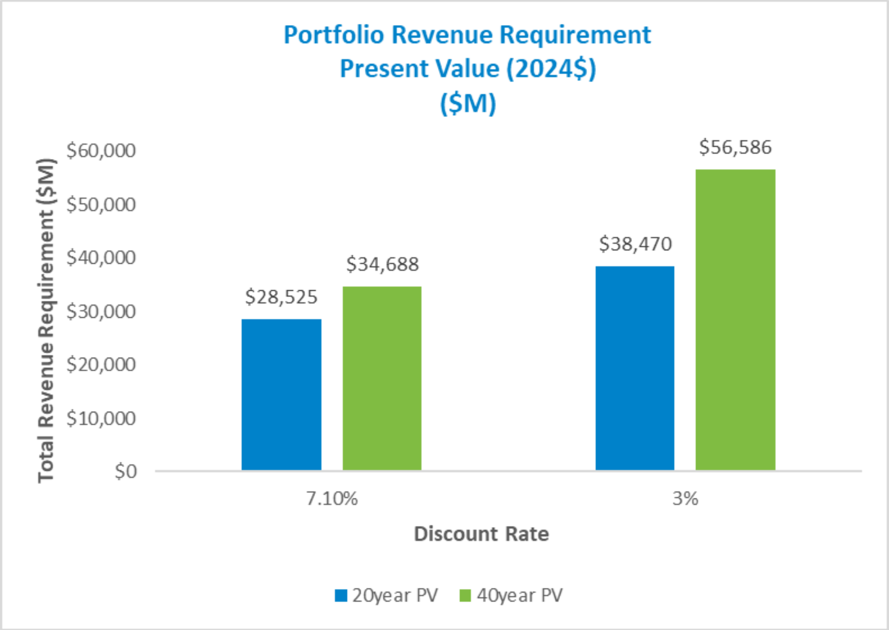
** Link to LRTP Tranche 2.1 metrics whitepaper.*

# Common assumptions/variables used for evaluation of benefits

- Project recommendation is based on analysis of benefits over the 20-year time horizon starting with the assumed in-service date of the projects (2032)
- Benefits are also calculated for the 40-year time horizon to show potential value over the longer-term as projects will continue to be in-service
- Benefit cost analysis applies a discount rate of 7.1% which reflects the transmission owner weighted average cost of capital for transmission investments
- Additional analysis is performed using a discount rate of 3.0% for additional reference based on the social discount rate
- Present value calculations assume a long-term inflation rate of 2.5%.

# The LRTP Tranche 2.1 portfolio 20-year and 40-year total revenue requirements are calculated for a range of discount rates

- The estimated capital cost of LRTP Tranche 2.1 projects is $21.8B
- Total revenue requirement for the Tranche 2.1 portfolio is expected to be in the range of $28.5B – $34.7B* (7.1% discount rate)




*Estimated costs as of 9/19/2024

# MISO benefit cost analysis detailed results are provided for MISO Midwest Cost Allocation Zones: **20-years Lower Range**

| Footprint Benefits (minimum)- 20 Year NPV, 7.1%, 2024$ | | ($M) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Benefit Metric | CAZ Allocation Method | Zone 1 | Zone 2 | Zone 3 | Zone 4 | Zone 5 | Zone 6 | Zone 7 | Total |
| **Avoided Capacity Costs** | Based on load ratio share | $3,409 | $2,179 | $1,802 | $1,546 | $1,243 | $2,894 | $3,199 | $16,271 |
| **Capacity Savings from Reduced Losses** | Based on load ratio share | $389 | $249 | $206 | $176 | $142 | $330 | $365 | $1,857 |
| **Congestion and Fuel Savings** | Derived directly from PROMOD results | $1,366 | $2,546 | $1,689 | -$341 | $232 | $1,847 | $808 | $8,148 |
| **Energy Savings from Reduced Losses** | Derived directly from PROMOD results | $246 | $273 | $54 | $92 | $129 | $428 | $411 | $1,632 |
| **Reduced Transmission Outage Costs** | Derived directly from PROMOD results | $31 | $14 | -$34 | -$3 | $69 | $22 | -$22 | $76 |
| **Reduced Risks from Extreme Weather Impacts*** | Based on load ratio share | $82 | $53 | $44 | $37 | $30 | $70 | $77 | $394 |
| **Avoided Transmission Investment** | Based on the zonal location of upgrade | $292 | $435 | $85 | $154 | $161 | $59 | $42 | $1,228 |
| **Mitigation of Reliability Issues*** | Based on location of issues | $6,021 | $3,917 | $922 | $1,286 | $353 | $1,746 | $575 | $14,821 |
| **Decarbonization**** | Based on load ratio share | $1,515 | $968 | $801 | $687 | $552 | $1,286 | $1,421 | $7,230 |
| | | | | | | | | | |
| Total Benefits | | $13,352 | $10,633 | $5,569 | $3,635 | $2,910 | $8,681 | $6,876 | $51,657 |
| Total Costs | | $5,977 | $3,821 | $3,159 | $2,709 | $2,179 | $5,073 | $5,608 | $28,525 |
| B/C | | 2.2 | 2.8 | 1.8 | 1.3 | 1.3 | 1.7 | 1.2 | 1.8 |

* VOLL: min=$3,500

**Carbon Price: min=$85

# MISO benefit cost analysis detailed results are provided for MISO Midwest Cost Allocation Zones: **20-years Upper Range**

| Footprint Benefits (maximum)- 20 Year NPV, 7.1%, 2024$ | | ($M) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Benefit Metric | CAZ Allocation Method | Zone 1 | Zone 2 | Zone 3 | Zone 4 | Zone 5 | Zone 6 | Zone 7 | Total |
| **Avoided Capacity Costs** | Based on load ratio share | $3,409 | $2,179 | $1,802 | $1,546 | $1,243 | $2,894 | $3,199 | $16,271 |
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| **Reduced Transmission Outage Costs** | Derived directly from PROMOD results | $31 | $14 | -$34 | -$3 | $69 | $22 | -$22 | $76 |
| **Reduced Risks from Extreme Weather Impacts*** | Based on load ratio share | $236 | $151 | $125 | $107 | $86 | $200 | $221 | $1,124 |
| **Avoided Transmission Investment** | Based on the zonal location of upgrade | $292 | $435 | $85 | $154 | $161 | $59 | $42 | $1,228 |
| **Mitigation of Reliability Issues*** | Based on location of issues | $17,204 | $11,190 | $2,635 | $3,675 | $1,010 | $4,988 | $1,642 | $42,345 |
| **Decarbonization**** | Based on load ratio share | $5,931 | $3,792 | $3,135 | $2,689 | $2,162 | $5,034 | $5,565 | $28,308 |
| | | | | | | | | | |
| Total Benefits | | $29,105 | $20,828 | $9,696 | $8,096 | $5,232 | $15,802 | $12,231 | $100,990 |
| Total Costs | | $5,977 | $3,821 | $3,159 | $2,709 | $2,179 | $5,073 | $5,608 | $28,525 |
| B/C | | 4.9 | 5.5 | 3.1 | 3.0 | 2.4 | 3.1 | 2.2 | 3.5 |

* VOLL: max=$10,000

**Carbon Price: max=$248.67

# MISO benefit cost analysis detailed results are provided for MISO Midwest Cost Allocation Zones: **40-years Lower Range**

| Footprint Benefits (minimum)- 40 Year NPV, 7.1%, 2024$ | | ($M) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Benefit Metric | CAZ Allocation Method | Zone 1 | Zone 2 | Zone 3 | Zone 4 | Zone 5 | Zone 6 | Zone 7 | Total |
| **Avoided Capacity Costs** | Based on load ratio share | $4,025 | $2,573 | $2,127 | $1,825 | $1,467 | $3,416 | $3,776 | $19,210 |
| **Capacity Savings from Reduced Losses** | Based on load ratio share | $459 | $294 | $243 | $208 | $167 | $390 | $431 | $2,193 |
| **Congestion and Fuel Savings** | Derived directly from PROMOD results | $2,856 | $3,888 | $1,000 | -$255 | $645 | $2,607 | $531 | $11,272 |
| **Energy Savings from Reduced Losses** | Derived directly from PROMOD results | $388 | $356 | $153 | $168 | $176 | $584 | $551 | $2,376 |
| **Reduced Transmission Outage Costs** | Derived directly from PROMOD results | $49 | $8 | -$26 | -$18 | $75 | $40 | -$18 | $110 |
| **Reduced Risks from Extreme Weather Impacts*** | Based on load ratio share | $117 | $75 | $62 | $53 | $43 | $99 | $110 | $557 |
| **Avoided Transmission Investment** | Based on the zonal location of upgrade | $422 | $627 | $122 | $223 | $232 | $85 | $61 | $1,773 |
| **Mitigation of Reliability Issues*** | Based on location of issues | $6,021 | $3,917 | $922 | $1,286 | $353 | $1,746 | $575 | $14,821 |
| **Decarbonization**** | Based on load ratio share | $1,877 | $1,200 | $992 | $851 | $684 | $1,593 | $1,761 | $8,960 |
| | | | | | | | | | |
| Total Benefits | | $16,215 | $12,937 | $5,596 | $4,341 | $3,843 | $10,560 | $7,779 | $61,271 |
| Total Costs | | $7,268 | $4,646 | $3,842 | $3,295 | $2,650 | $6,169 | $6,819 | $34,688 |
| B/C | | 2.2 | 2.8 | 1.5 | 1.3 | 1.5 | 1.7 | 1.1 | 1.8 |

* VOLL: min=$3,500

**Carbon Price: min=$85

# MISO benefit cost analysis detailed results are provided for MISO Midwest Cost Allocation Zones: **40-years Upper Range**

| Footprint Benefits (maximum)- 40 Year NPV, 7.1%, 2024$ | | ($M) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Benefit Metric | CAZ Allocation Method | Zone 1 | Zone 2 | Zone 3 | Zone 4 | Zone 5 | Zone 6 | Zone 7 | Total |
| **Avoided Capacity Costs** | Based on load ratio share | $4,025 | $2,573 | $2,127 | $1,825 | $1,467 | $3,416 | $3,776 | $19,210 |
| **Capacity Savings from Reduced Losses** | Based on load ratio share | $459 | $294 | $243 | $208 | $167 | $390 | $431 | $2,193 |
| **Congestion and Fuel Savings** | Derived directly from PROMOD results | $2,856 | $3,888 | $1,000 | -$255 | $645 | $2,607 | $531 | $11,272 |
| **Energy Savings from Reduced Losses** | Derived directly from PROMOD results | $388 | $356 | $153 | $168 | $176 | $584 | $551 | $2,376 |
| **Reduced Transmission Outage Costs** | Derived directly from PROMOD results | $49 | $8 | -$26 | -$18 | $75 | $40 | -$18 | $110 |
| **Reduced Risks from Extreme Weather Impacts*** | Based on load ratio share | $333 | $213 | $176 | $151 | $122 | $283 | $313 | $1,592 |
| **Avoided Transmission Investment** | Based on the zonal location of upgrade | $422 | $627 | $122 | $223 | $232 | $85 | $61 | $1,773 |
| **Mitigation of Reliability Issues*** | Based on location of issues | $17,204 | $11,190 | $2,635 | $3,675 | $1,010 | $4,988 | $1,642 | $42,345 |
| **Decarbonization**** | Based on load ratio share | $7,753 | $4,956 | $4,098 | $3,515 | $2,826 | $6,580 | $7,274 | $37,002 |
| | | | | | | | | | |
| Total Benefits | | $33,490 | $24,106 | $10,528 | $9,492 | $6,720 | $18,973 | $14,563 | $117,872 |
| Total Costs | | $7,268 | $4,646 | $3,842 | $3,295 | $2,650 | $6,169 | $6,819 | $34,688 |
| B/C | | 4.6 | 5.2 | 2.7 | 2.9 | 2.5 | 3.1 | 2.1 | 3.4 |

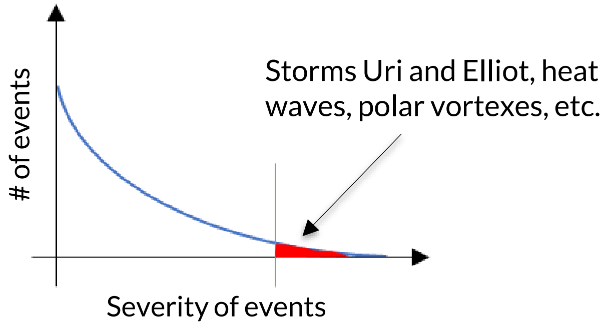
* VOLL: max=$10,000

**Carbon Price: max=$248.67

# Reduced Risks from Extreme Weather Impacts

# The reduced risk from extreme weather impacts measures the change in the expected unserved energy (EUE) during the most severe events

- This benefit accounts for the duration and magnitude of loss of load events during extreme weather conditions (e.g., Storm Uri, 2014 and 2019 Polar Vortex)
    - Adding transmission capacity increases import/export limits, which enables access to capacity across the footprint
    - Access to a larger pool of capacity reduces the magnitude of loss of load events during extreme weather conditions
- Reduced severity of events under extreme cases are additional benefits that are not explicitly reflected in metrics like LOLE
    - The LOLE metric is a counting metric (e.g., 1 day-event), whereas EUE captures both magnitude and duration (e.g., 700 MWh)
    - LOLE is an expected value (e.g., long-term average), whereas this metric focuses on the most "severe" system conditions

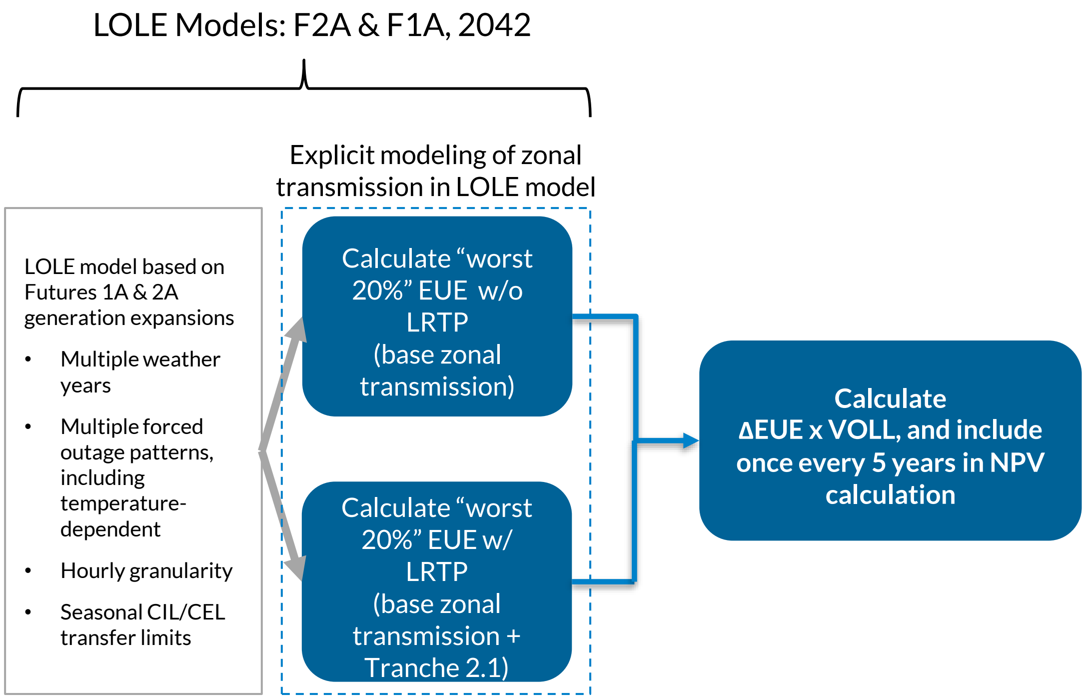



Illustrative distribution of risk



LOLE - Loss of Load Expectation

# The reduced risk from extreme weather impacts leverages LOLE modeling and incorporates a simplified representation of transmission constraints at the zonal level




- Simplified representation of transmission constraints at the zonal level are based on seasonal capacity import (CIL) and export limits (CEL)
- The average of the worst 20% events (in terms of energy "unserved") is calculated for each case. Energy unserved includes voluntary and involuntary load shedding
- Benefits are attributed to greater EUE without Tranche 2.1
  - EUE w/o Tranche 2.1 > EUE w/ Tranche 2.1
- Economic value is determined by multiplying the delta EUE with the value of loss of load (VOLL)
  - $(\Delta EUE_{20\%})$ x (VOLL)



ACC – Avoided Capital Cost; LOLE – Loss of Load Expectation; LRZ – Locational Resource Zone; CIL – Capacity Import Limit; CEL – Capacity Export Limit

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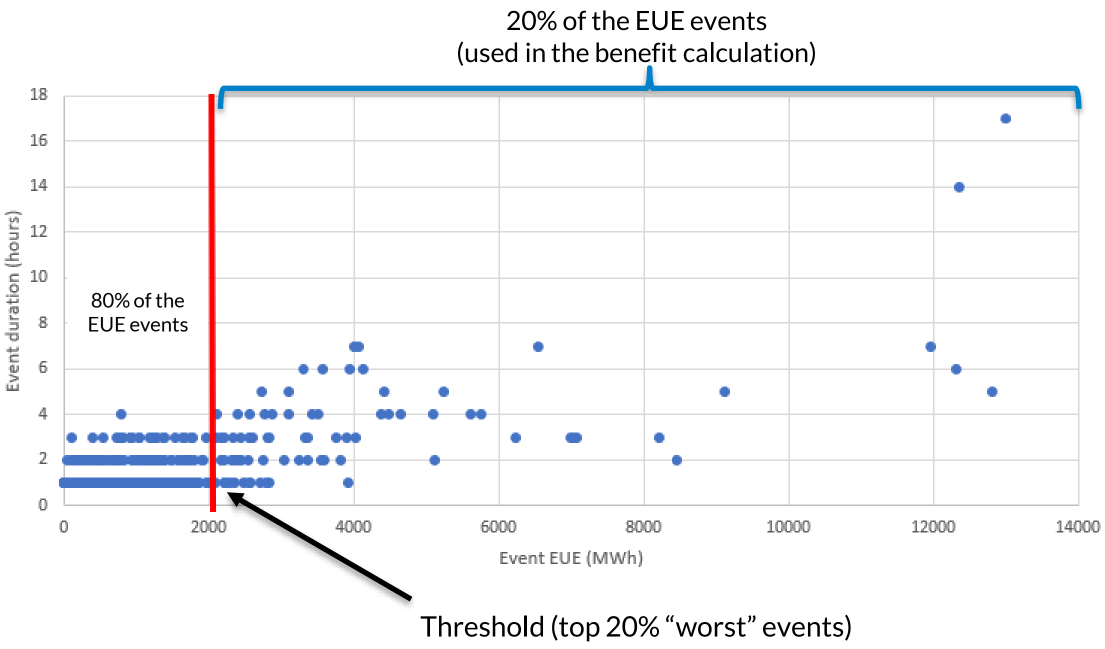
# The distribution of loss of load events informs the threshold to be used for the reduced risk from extreme weather benefit

- The risk distribution shows a cluster of extreme events beyond the 2,000 MWh EUE and 4-hour duration thresholds

- The "worst" 20% EUE events (350 total) were averaged for the with/without LRTP cases

- This translates into a 1 in 5 years occurrence. The benefits are included in years 1, 5, 10, 15, and 20 of the 20-year NPV calculation

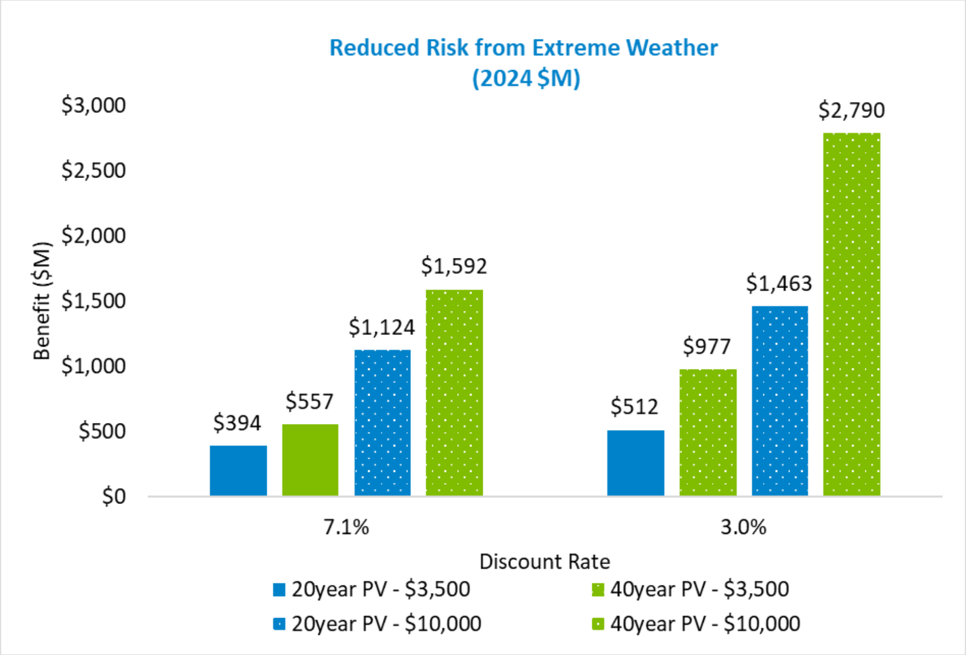





EUE: expected unserved energy | NPV: net present value

# The addition of LRTP transmission reduces the system unserved energy during the most extreme events

- The reduced risk from extreme weather impacts measures the change in the expected unserved energy (EUE) during the most severe events
- A VOLL equal to 3,500 $/MWh is used to monetize the lower end of this benefit and 10,000 $/MWh on the upper end
- The NPV benefits of Tranche 2.1 for a 20-year period are in the range of $394M-$557M






LOLE - Loss of Load Expectation

# Capacity Savings from Reduced Losses

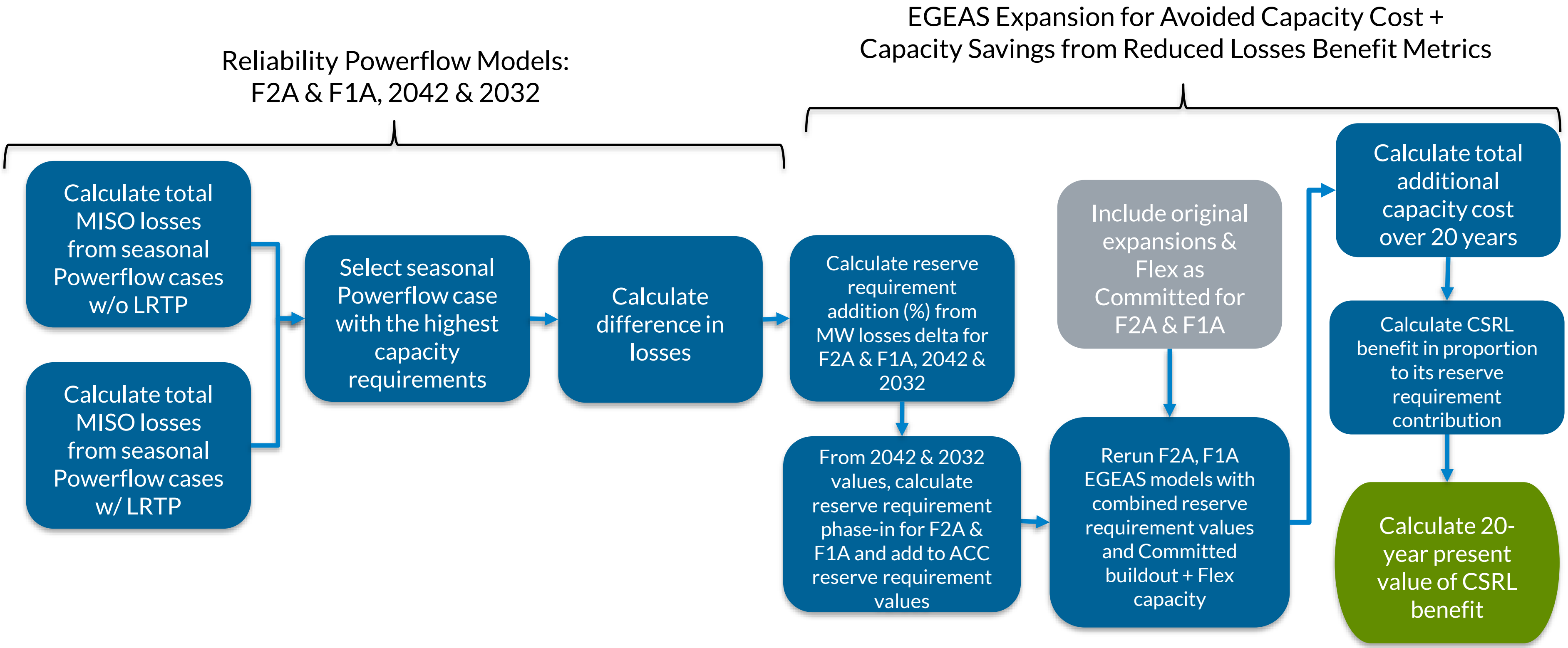
# Capacity Savings from Reduced Losses captures benefits from reduced system losses from the addition of transmission

- The increase in transmission capacity reduces the effective system impedance and redistributes flows from resources across the footprint to the load centers
- Less capacity is required to cover the lower system losses with the LRTP portfolio
- Losses are represented as additional reserve requirement in the incremental EGEAS resource expansion model
    - Losses are calculated from the reliability study models for season with highest reserve requirement
    - Expansion analysis is performed in combination with Avoided Capacity Cost to ensure no duplication
    - The Loss component is split out in proportion to total reserve adjustment applied in the EGEAS simulation



MISO

# Similarly, lower system losses reduces the requirements for additional capacity investment, as determined by reserve requirement changes and updated regional expansions

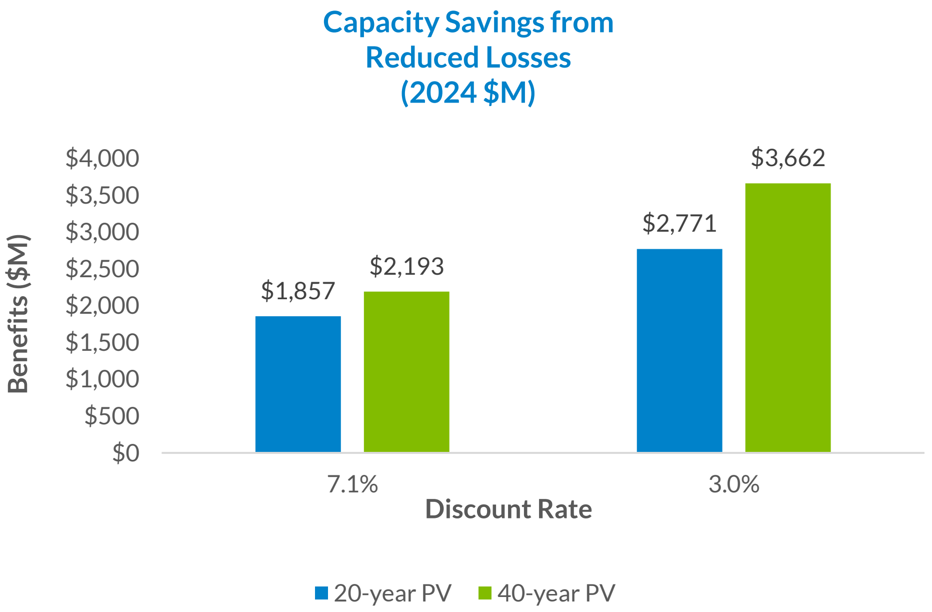





Losses assessed in real power (MW) as opposed to reactive power (MVAR)

# The decrease in system losses due to the addition of LRTP transmission reduces the amount of capacity reserves that would be need to cover system losses

- LRTP transmission lowers system losses, which reduces the need for more capacity investment and yields a 20-year present value benefit of $1.9B*



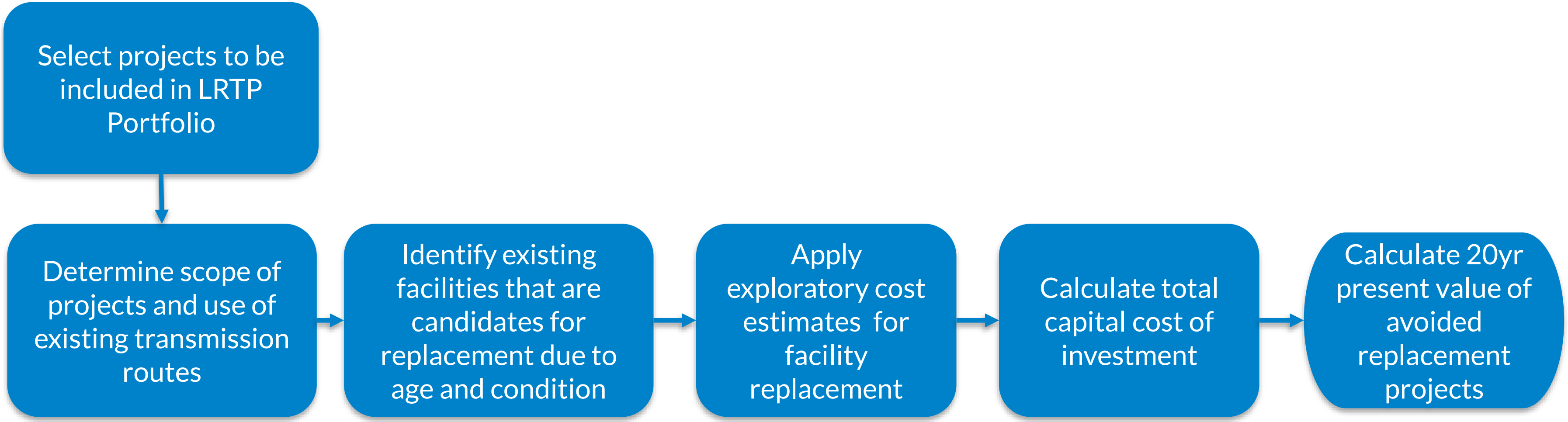

* Discount rate of 7.1%

# Avoided Transmission Investment

# Costs for age and condition replacement of transmission facilities are offset by rebuilds and co-location of LRTP projects along existing rights-of-way

- LRTP projects that require rebuild of existing facilities or co-location of new transmission lines with existing facilities avoids the need for future rebuild of the aging infrastructure
  - This is a conservative estimate of avoided transmission as it solely focuses on age-related transmission improvements.  Other reliability projects may be avoided but are not captured in this metric.
- Candidate facilities for age and condition replacement are identified in the LRTP project scoping effort and are confirmed with relevant transmission owners
- Avoided costs are developed using exploratory level cost estimates for complete replacement of the existing facility
- Replacement projects are assumed to be in service by the 20-year study period
- Costs are distributed over 5 years prior to the assumed in service date

# Avoided age and condition replacement candidates are identified in the scoping of Tranche 2.1 projects



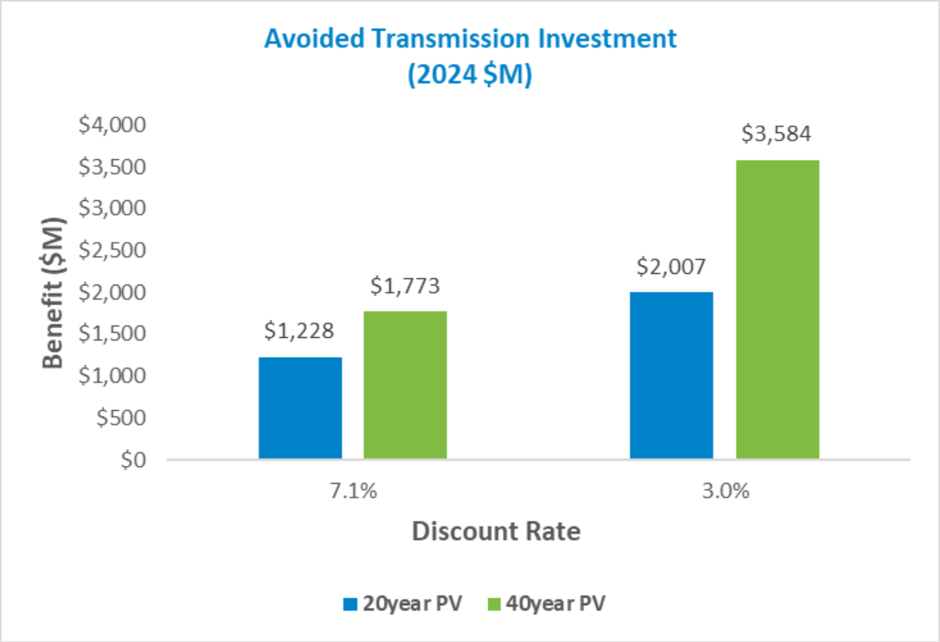
# Reuse of existing right-of-way for LRTP projects offsets the costs of age and condition replacement of aging facilities

Rebuild for capacity uprates and colocation of LRTP projects along existing facility rights-of-way avoids the need for future age and condition replacement.

*Facility Replacement Summary*

| *Voltage Class* | *Mileage* | *Cost($M)* |
|---|---|---|
| *345kV* | *208* | *$667* |
| *<345kV* | *500* | *$1,003* |

LRTP Tranche 2.1 portfolio avoids the need for replacement of over 700 miles of existing transmission and delivers 20-year present value benefits of $1.2B



# Congestion and Fuel Savings

# Congestion and Fuel Savings measures the reduction in congestion costs and generator production costs enabled by Tranche 2.1 transmission

- Transmission allows for more efficient access to low-cost resources and reduces congestion costs with a more economical dispatch of resources
- The Congestion and Fuel Savings benefit is a measure of Adjusted Production Cost (APC) savings between the LRTP Reference Case and LRTP Change Case
  - MISO's standard production cost models do not include transmission outages apart from N-1 constraints in economic dispatch
    - This yields a conservative estimate of production cost benefits.
- LRTP Reference Case includes base MTEP transmission topology, and includes the generation portfolio identified through the Futures Series 1A
- LRTP Change Case includes everything in the LRTP Reference Case, with the addition of Tranche 2.1 transmission

# APC savings will be determined by measuring the reduction of MISO Midwest APC in the LRTP Reference Case compared to MISO Midwest APC in the LRTP Change Case

**Make-up of LRTP Tranche 2 F2A Reference Case Model**

- MTEP Topology
- Future Load Forecast
- Existing + Signed GIA Units
- Model-built* DGPV**
- Committed/Model-built Battery Storage
- Resource sites enabled by Tranche 1 Portfolio
- Flex Resources
- Committed Resources
- Model-built Resources

−

**Make-up of LRTP Tranche 2.1 F2A Change Case Model**

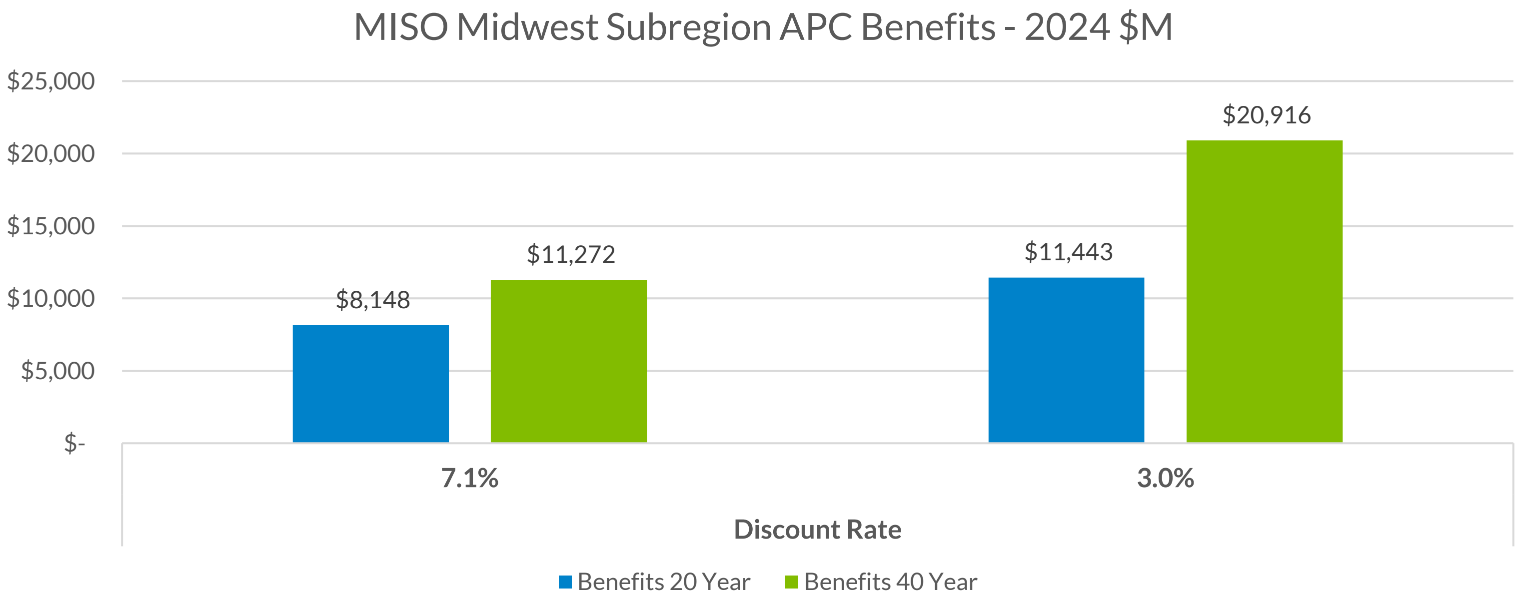
- Reference Case
- LRTP Tranche 2.1 Transmission

= **APC Savings**

*Model-built resources are those added through the Futures expansion
**Distributed Solar PV Generation

1. MISO's APC White Paper

# LRTP Tranche 2.1 transmission projects congestion and fuel savings results




- MISO Midwest Subregion realizes $8.1B in congestion and fuel savings over a 20-year period
- MISO Midwest Subregion realizes $11.3B in congestion and fuel savings over a 40-year period

NPV benefits in millions of 2024 dollars, including 2.5% annual inflation for Min/Max prices at discount rates above.
20-year and 40-year benefits refer to projects' in-service value to 2052 and 2072, respectively.
Emissions data interpolated between PROMOD model years 2032, 2037, and 2042; and extrapolated post-2042.

# LRTP Tranche 2.1 transmission projects congestion and fuel savings results

| Present Value | 20 year PV (Millions 2024$) | | 40 year PV (Millions - 2024$) | |
|---|---|---|---|---|
| Discount Rate | 7.1% | 3.0% | 7.1% | 3.0% |
| **CAZ** | | | | |
| **1** | **$1,366** | **$2,236** | **$2,856** | **$6,876** |
| **2** | **$2,546** | **$3,698** | **$3,888** | **$7,809** |
| **3** | **$1,689** | **$1,932** | **$1,000** | **-$326** |
| **4** | **-$341** | **-$407** | **-$255** | **-$121** |
| **5** | **$232** | **$433** | **$645** | **$1,727** |
| **6** | **$1,847** | **$2,612** | **$2,607** | **$4,922** |
| **7** | **$808** | **$940** | **$531** | **$31** |
| **Total** | **$8,148** | **$11,443** | **$11,272** | **$20,916** |

- MISO Midwest Subregion realizes $8.1B in congestion and fuel savings over a 20-year period
- MISO Midwest Subregion realizes $11.3B in congestion and fuel savings over a 40-year period



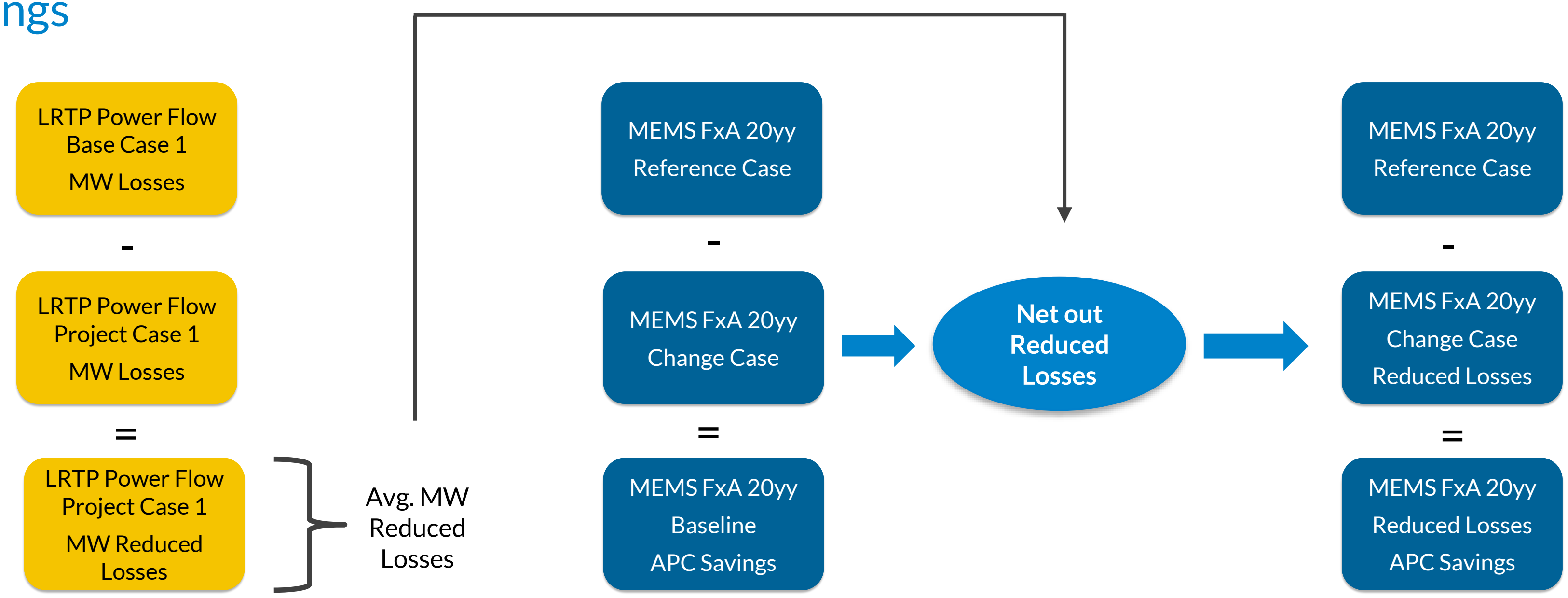
NPV benefits in millions of 2024 dollars, including 2.5% annual inflation for Min/Max prices at discount rates above.
20-year and 40-year benefits refer to projects' in-service value to 2052 and 2072, respectively.
Emissions data interpolated between PROMOD model years 2032, 2037, and 2042; and extrapolated post-2042.

# Energy Savings from Reduced Losses

# New transmission reduces flows on existing wires and can reduce transmission energy loss rates

- The future resource fleet described by our members and through our stakeholder process shows new generation throughout the system, increasing the likelihood that power will be transported over longer distances
- Extra-high voltage (e.g., 345 kV, 765 kV) provides additional lower-impedance paths resulting in reduced losses that lower operating and production costs
- MISO's standard production cost models incorporate transmission losses into fixed demand profiles, so loss energy values are not included in congestion and fuel savings
- The aggregate impact of reducing loss energy may be identified by measuring the incremental impact to Adjusted Production Cost (APC) when estimated loss reductions are netted out of demand
- This metric only quantifies reductions to production costs and does not quantify capital costs
  - PROMOD performs production cost simulations and does not evaluate resource expansion
  - The Capacity Savings from Reduced Losses metric calculates effective capital cost reductions and does not include operating costs

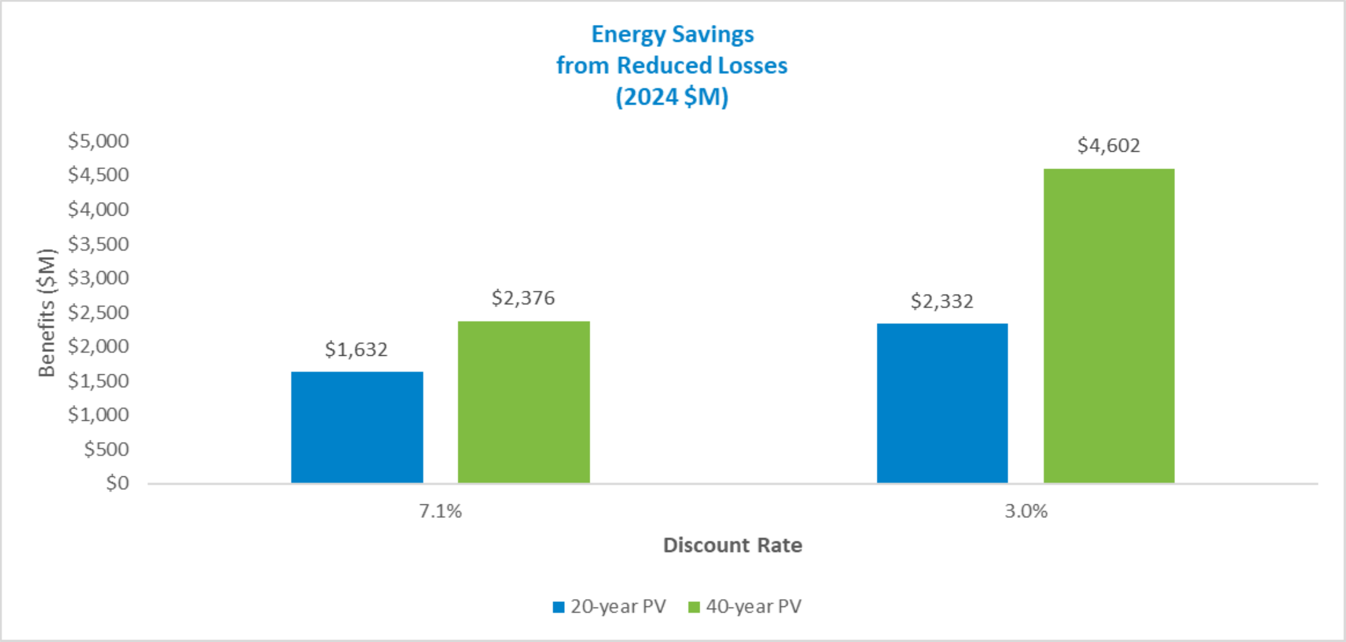
# Energy savings will be determined by measuring the additional APC savings when reduced losses are applied, beyond what is seen in the baseline Congestion and Fuel Savings




$$Energy\ Savings\ from\ Reduced\ Losses = Reduced\ Losses\ APC\ Savings\ -\ Baseline\ APC\ Savings$$

Reference Case: An unmodified base PROMOD case
Change Case: The same Change Case used in other value metrics, where new prospective transmission has been added to the Reference Case
MEMS FxA 20yy: MISO Economic Model Series, Future FxA, Year 20yy

# LRTP Tranche 2.1 transmission projects energy savings from reduced losses results




- MISO Midwest Subregion realizes $1.6B in energy savings from reduced losses over a 20 year period
- MISO Midwest Subregion realizes $2.4B in energy savings from reduced losses over 40 year period

NPV benefits in millions of 2024 dollars, including 2.5% annual inflation for Min/Max prices at discount rates above.
20-year and 40-year benefits refer to projects' in-service value to 2052 and 2072, respectively.
Emissions data interpolated between PROMOD model years 2032, 2037, and 2042; and extrapolated post-2042.

# LRTP Tranche 2.1 transmission projects energy savings from reduced losses results

| Present Value | 20 year PV (Millions 2024$) | | 40 year PV (Millions - 2024$) | |
|---|---|---|---|---|
| Discount Rate | 7.1% | 3.0% | 7.1% | 3.0% |
| **CAZ** | | | | |
| **1** | **$246** | **$361** | **$388** | **$799** |
| **2** | **$273** | **$376** | **$356** | **$626** |
| **3** | **$54** | **$102** | **$153** | **$413** |
| **4** | **$92** | **$143** | **$168** | **$379** |
| **5** | **$129** | **$180** | **$176** | **$323** |
| **6** | **$428** | **$598** | **$584** | **$1,069** |
| **7** | **$411** | **$571** | **$551** | **$993** |
| **Total** | **$1,632** | **$2,332** | **$2,376** | **$4,602** |

- MISO Midwest Subregion realizes $1.6B in energy savings from reduced losses over a 20 year period
- MISO Midwest Subregion realizes $2.3B in energy savings from reduced losses over 40 year period



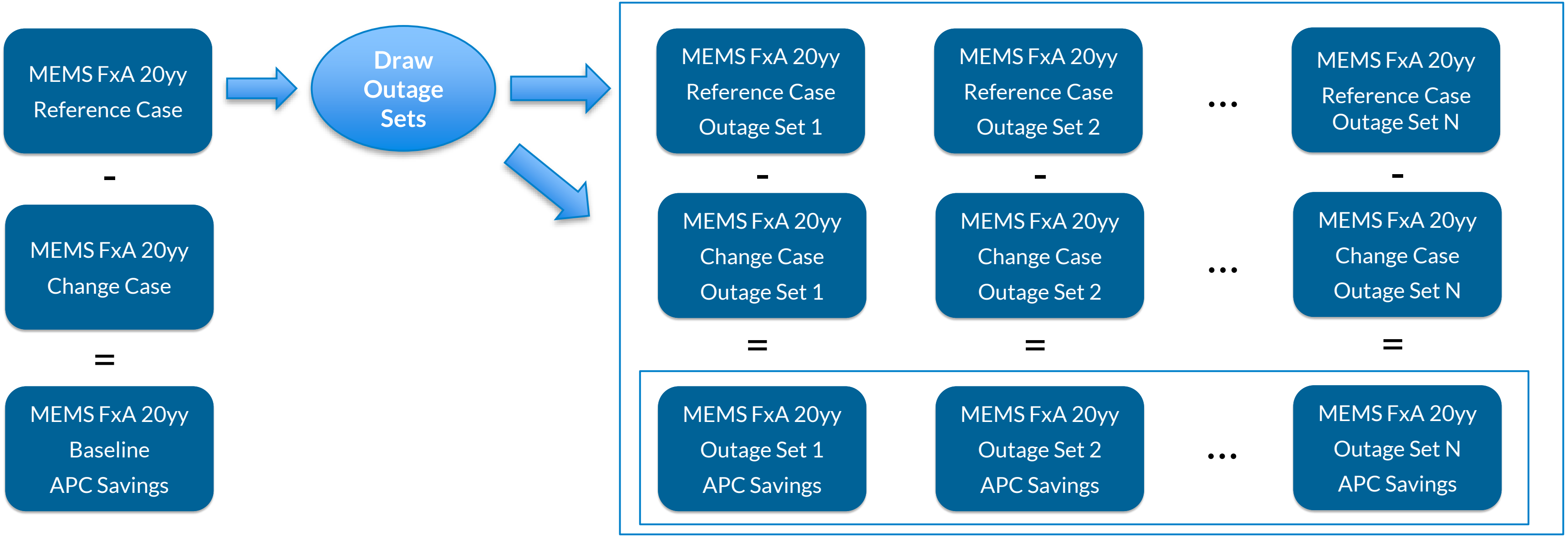
NPV benefits in millions of 2024 dollars, including 2.5% annual inflation for Min/Max prices at discount rates above.
20-year and 40-year benefits refer to projects' in-service value to 2052 and 2072, respectively.
Emissions data interpolated between PROMOD model years 2032, 2037, and 2042; and extrapolated post-2042.

# Reduced Transmission Outage Costs

# Transmission outages reduce operational transmission capacity and can impact congestion

- Planned and forced transmission outages are a common daily occurrence on a system-wide basis
- Transmission outages shift flows onto parallel paths, increasing loading, reducing redundancy and often increasing congestion
- MISO's standard production cost models do not include transmission outages apart from N-1 constraints in economic dispatch
    - MISO does not believe that this captures all real time congestion and reflects a conservative value
- The aggregate impact of outages may be identified by measuring the incremental impact to Adjusted Production Cost (APC) when forced and planned outages are simulated
- New transmission provides increased capacity and redundancy, and may reduce the impact of transmission outages

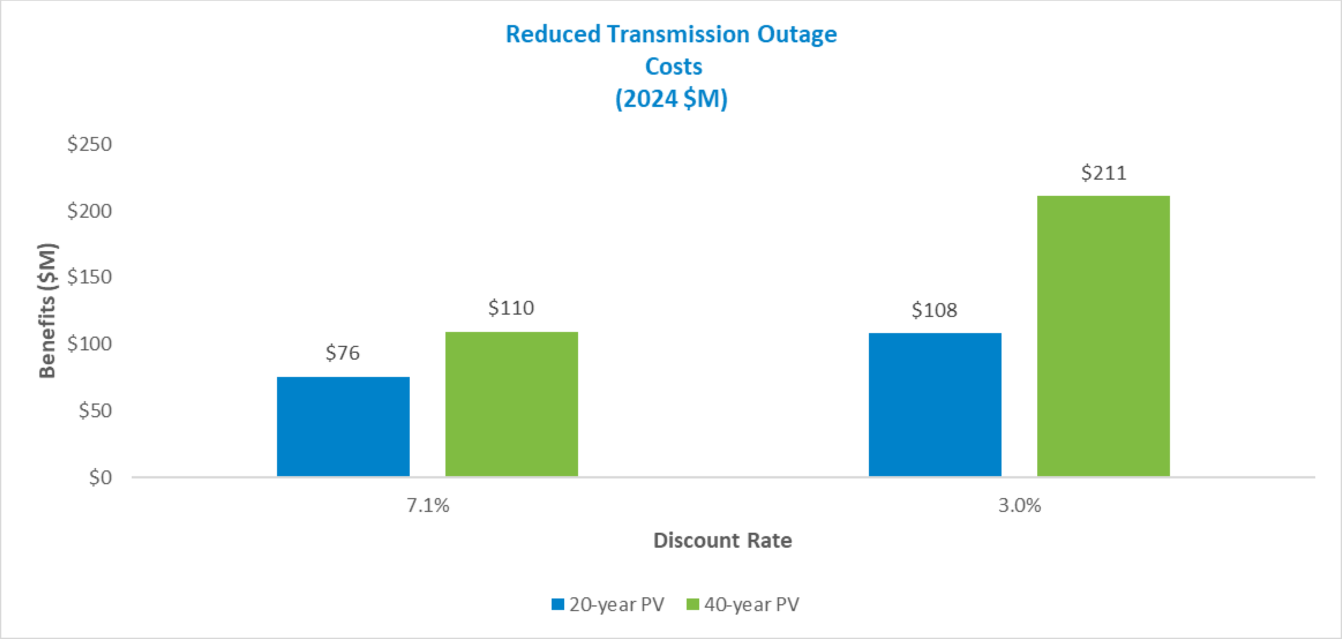
## Reduced Transmission Outage Costs will be determined by measuring the average increase in APC savings when Transmission Outages are simulated, beyond what is seen in the baseline Congestion and Fuel Savings




$$\textit{Reduced Transmission Outage Costs} = \frac{\sum_n \textit{Outage Set } n \textit{ APC Savings}}{N} - \textit{Baseline APC Savings}$$

Reference Case: An unmodified base PROMOD case
Change Case: The same Change Case used in other value metrics, where new prospective transmission has been added to the Reference Case
MEMS FxA 20yy: MISO Economic Model Series, Future FxA, Year 20yy

# LRTP Tranche 2.1 transmission projects benefits from reduced transmission outage costs results




- MISO Midwest Subregion realizes $76M in reduced transmission outage costs over a 20 year period
- MISO Midwest Subregion realizes $110M in reduced transmission outage costs over 40 year period



NPV benefits in millions of 2024 dollars, including 2.5% annual inflation for Min/Max prices at discount rates above.
20-year and 40-year benefits refer to projects' in-service value to 2052 and 2072, respectively.
Emissions data interpolated between PROMOD model years 2032, 2037, and 2042; and extrapolated post-2042.

# LRTP Tranche 2.1 transmission projects benefits from reduced transmission outage costs results

| Present Value | 20 year PV (2024$) | | 40 year PV (2024$) | |
|---|---|---|---|---|
| Discount Rate | 7.1% | 3.0% | 7.1% | 3.0% |
| **CAZ** | | | | |
| **1** | **$31** | **$46** | **$49** | **$100** |
| **2** | **$14** | **$16** | **$8** | **-$2** |
| **3** | **-$34** | **-$40** | **-$26** | **-$15** |
| **4** | **-$3** | **-$9** | **-$18** | **-$56** |
| **5** | **$69** | **$90** | **$75** | **$106** |
| **6** | **$22** | **$34** | **$40** | **$91** |
| **7** | **-$22** | **-$27** | **-$18** | **-$12** |
| **Total** | **$76** | **$108** | **$110** | **$211** |

- MISO Midwest Subregion realizes $76M in reduced transmission outage costs over a 20 year period
- MISO Midwest Subregion realizes $110M in reduced transmission outage costs over 40 year period

NPV benefits in millions of 2024 dollars, including 2.5% annual inflation for Min/Max prices at discount rates above.
20-year and 40-year benefits refer to projects' in-service value to 2052 and 2072, respectively.
Emissions data interpolated between PROMOD model years 2032, 2037, and 2042; and extrapolated post-2042.

# Decarbonization

# The Decarbonization metric captures LRTP's long-term benefits of reducing $CO_2$ emissions by enabling reliable delivery of low-cost, clean energy

- Tranche 2.1 benefit updated $CO_2$ costs and used the same method from Tranche 1:
  - Determine avoided emissions from LRTP economic production cost models
  - Convert emissions amounts to metric tons
  - Apply carbon costs to calculate 20- and 40-year NPV of avoided emissions

20-Year $CO_2$ Emissions Avoided: 127M metric tons

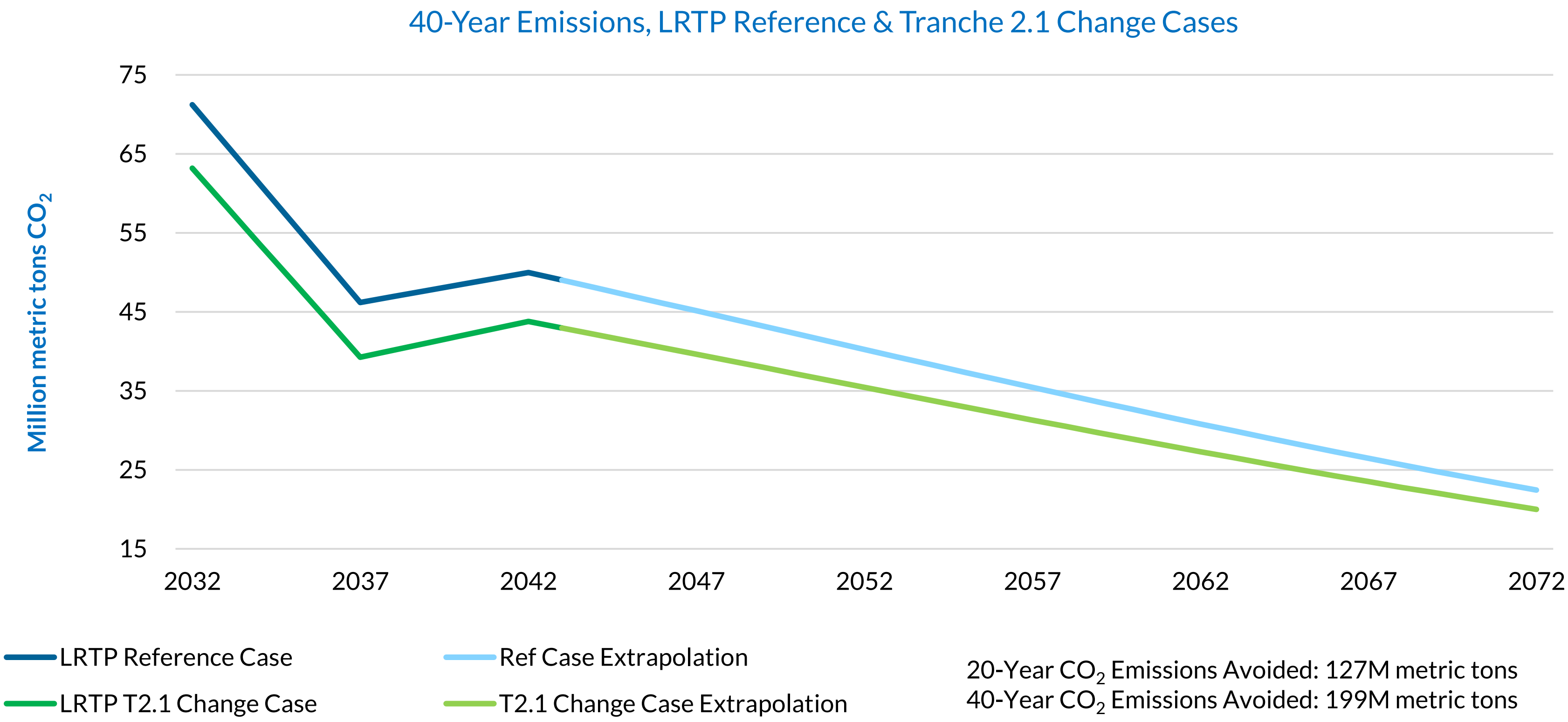
40-Year $CO_2$ Emissions Avoided: 199M metric tons

| | 7.1% Discount Rate | | 3% Discount Rate | |
|---|---|---|---|---|
| 2024$/metric ton | Federal (Min) $85 | MN PUC (Max) $249 | Federal (Min) $85 | MN PUC (Max) $249 |
| 20-Year Benefit (2024$, M) | $7,230 | $28,308 | $9,837 | $39,221 |
| 40-Year Benefit (2024$, M) | $8,960 | $37,002 | $14,925 | $65,094 |

Prices converted to 2024$
Metric ton = tonne
NPV = Net Present Value

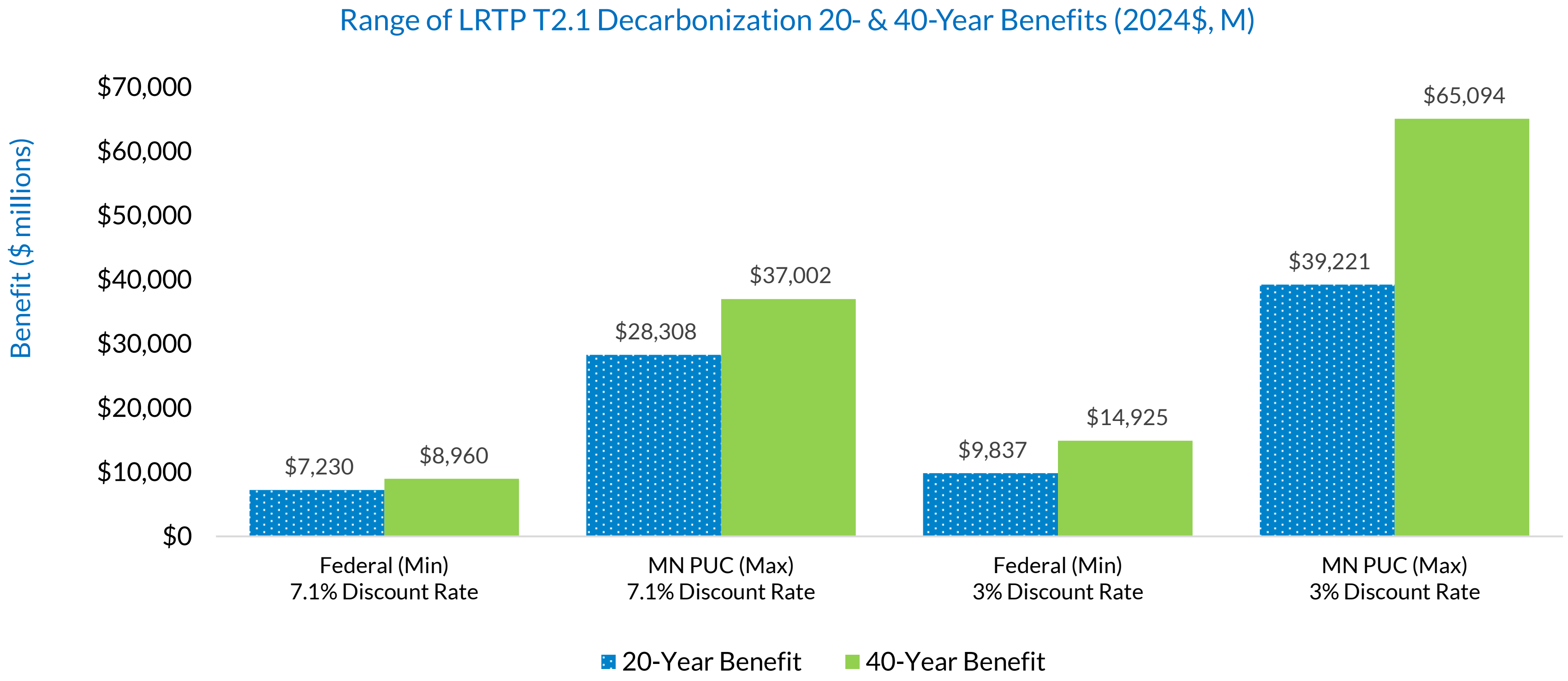
Federal = Updated 45Q Federal Tax Credit from Inflation Reduction Act of 2022;
Minnesota Public Utility Commission SF 4, 1st Engrossment 93rd MN Legislature, 16.4;
EPA Report on the Social Cost of Greenhouse Gases, November 2023

# LRTP Change Case illustrates the emissions reduced through enabled resources




20-Year $CO_2$ Emissions Avoided: 127M metric tons
40-Year $CO_2$ Emissions Avoided: 199M metric tons

# With the price range utilized, Decarbonization benefits range from $7B to $65B over 40 years of project life




NPV benefits in millions of 2024 dollars, including 2.5% annual inflation for Min/Max prices at discount rates above.
20-year and 40-year benefits refer to projects' in-service value to 2052 and 2072, respectively.
Emissions data interpolated between PROMOD model years 2032, 2037, and 2042; and extrapolated post-2042.