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# Changes under Order 1920A Plus Scenario Planning Under Orders 1920/1920A

Lauren Azar

Azar Law LLC

Lauren@azarlawllc.com

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NARUC State Transmission Working Group



# Today's Agenda

1. Order 1920A: what are the top material changes to Order 1920 as it relates to states' role in both cost allocation and planning?
  
2. Scenario Planning:
  - a) Description of what scenario planning is and why it has been used for long-term planning in many industries for decades.
  - b) Example of scenario planning in Midcontinent Independent System Operator (MISO).
  - c) Where the states have the most levers to influence scenario planning under Order 1920/1920A.



# **Order 1920A – Changes/Clarifications to Cost Allocation**

**Not all changes and clarifications are captured here.**



# What are some of the Cost Allocation Changes/Clarifications in Order 1920A?

- Relevant State Entities (RSEs) may request a 6-month extension to the initial Engagement Period, for a total period of 12 months.
- If the RSEs propose their own *Ex Ante* Method(s) and/or develop a State Agreement PROCESS (SAP), then Transmission Providers (TPs) must submit them to FERC on compliance even if the TPs dislike it (them).



# New/Clarified in Order 1920A Cost-Allocation

- Upon request from RSEs, TPs must:
  - “facilitate and participate” in cost allocation discussions during the Engagement Period.
  - run “a reasonable number” of additional analyses to “inform” cost allocation discussions.
- If TPs revise the allocation methods or SAP in the future, TPs must provide RSEs input opportunities.
- PJM Agreement Approach is still valid outside of the context of Orders 1000 and 1920.
- Voluntary Funding methods are not prohibited under Order 1920 and TPs/RSEs may submit them on compliance or RSEs may propose them as a State Agreement METHOD.



# **Order 1920A**

# **Changes/Clarifications to**

# **Regional Long-Term Planning**

**Not all changes and clarifications are captured here.**



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# What are Some of the Changes/ Clarifications in Scenario Planning Under 1920A?

- RSEs' role is increased for Scenario development. TPs must now:
  - "Consult with and consider the positions of" states relating to states' laws, policies and regulations.
  - For states with integrated resource plans (IRPs), include at least one of the states' preferred "trajectories" in the required Scenarios.
- Corporate Goals are no longer explicitly required in the inputs for the Scenarios; Corporate Goals must still be considered if they will affect Long-Term Transmission Needs and are not captured elsewhere.



# New in Order 1920A Planning

- Informing the Identification of Long-Term Transmission Needs: “should rely on economic and reliability drivers.”
- TPs are “strongly encouraged” to consider state-supported selection criteria for Facilities.
- Start of the First Planning Cycle – must begin two years (not one year) after the compliance deadline.



# Potential Planning Cycle Timelines

If RSEs request 6-month extension for the Engagement Period, then:

- Compliance Deadline automatically extended until 12/2025
- Initial Planning Cycle starts no later than 12/2027
- Initial Planning Cycle ends no later than 12/2030
- Second Planning Cycle must begin no later than 5 years from the Initial Planning Cycle, by 12/2032.



# **Scenario Planning – An Introduction**



# Why Scenario Planning?

The future is always uncertain. ... But sometimes, there is a high level of uncertainty.

Scenario planning is especially useful in designing infrastructure plans when

1. The level of uncertainty is high,
2. Technologies are rapidly changing, and
3. The time it takes to develop the new infrastructure is long.

Formally used since the 1960s...

- Royal Dutch Shell started using it for its infrastructure plans during the oil crisis.
- Rand Corporation developed long-range forecasting used by, among others, governments and the military.



# What is Scenario Planning? Step 1

Define future hypothetical worlds (“Futures” or “Scenarios”) When doing regional transmission planning, the Futures define the type and location of generation/storage resources and, may or may not, reflect differing transmission grids.

Ensure that the Futures defined are:

1. Plausible
2. Diverse = “a reasonable range of probable future outcomes consistent with the requirement for plausibility, based on assumptions about the factors and data inputs” under Order 1920A
3. Based on known future events and trends; Order 1920 requires “best available data”.



# What is Scenario Planning? Next Steps

After finalizing the Futures,

Step 2: identify the Needs created by those Futures.

Step 3: design potential Solutions for those Needs then:

- Compare the potential solutions to see which solutions would apply to most or all of the Futures.
- The best solutions are those that would accommodate the bookended scenarios and everything in between – called “least regrets”.
- Under Orders 1920/1920A, the potential solutions must not only include transmission but also dynamic line ratings, advanced power flow control devices, advanced conductors and transmission switching.



# **Scenario Planning Example from MISO's Long-Range Transmission Planning (LRTP) Tranche 2.1**



# MISO's 7-Step LRTP Process

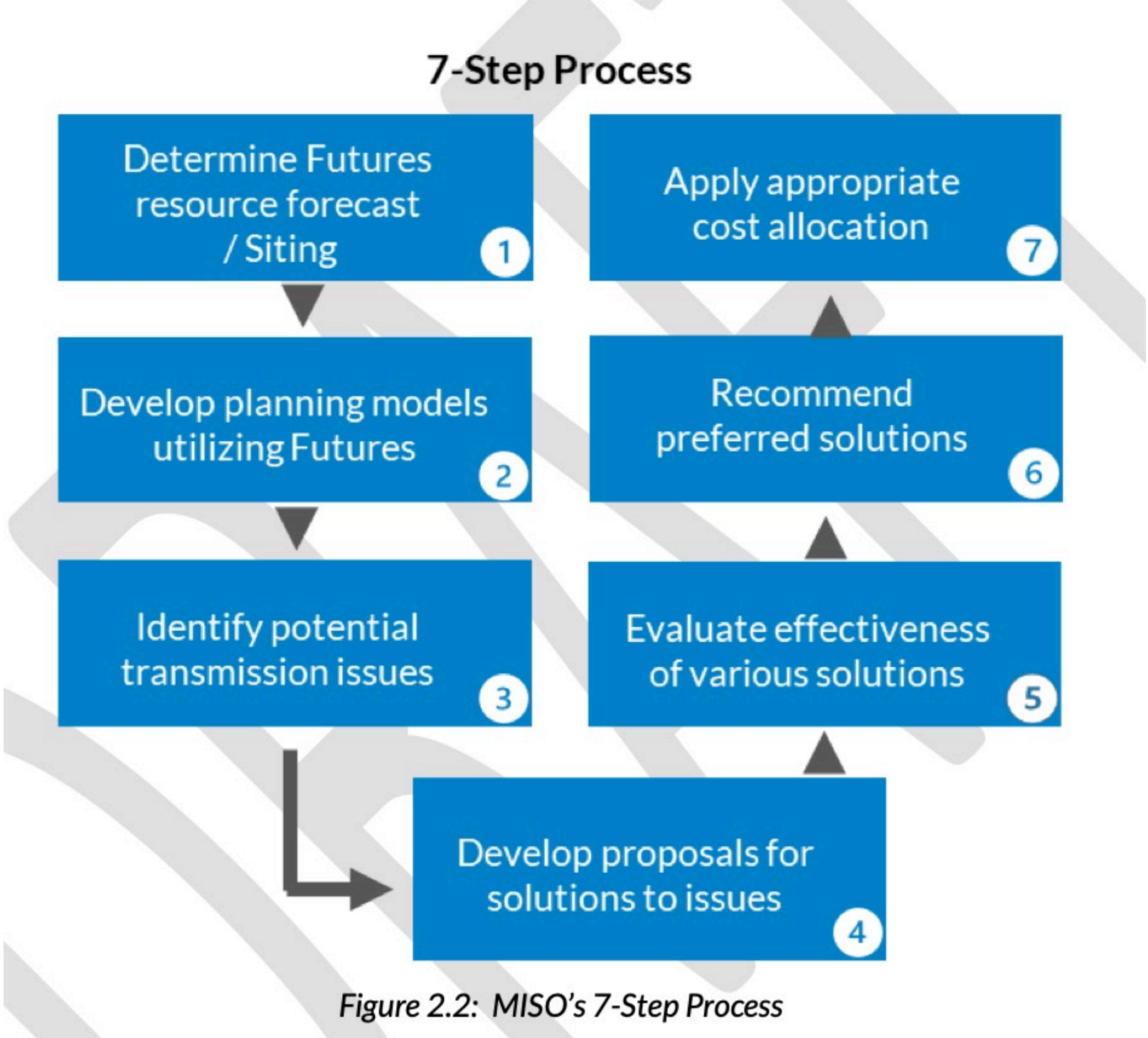


Figure 2.2: MISO's 7-Step Process

- Step 1** Futures establish potential scenarios for resource mix and load in the 20-year horizon; key parameters are load, reserves, costs, emissions, renewable energy targets, etc.
- Step 2** Models capture a range of conditions, for steady state, dynamic reliability, resilience and economic values
- Step 3-5** Applicable reliability and economic criteria are applied to find potential issues
- Step 4-5** Alternatives are provided by MISO and stakeholders
- Step 6** Recommend projects to ensure reliability, cost-effectiveness over time and economic values with stakeholder review and input
- Step 7** Tariff-based cost allocation depending on project classification tied to project benefits

# **MISO: Defining the Futures**



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# What are Some Key “Factors” in Designing MISO's Futures?

Annual Capital Costs by Fuel Type: “moderate values” contained in National Renewable Energy Lab's (NREL) Annual Technology Baseline (ATC) for all resources except for a handful.

## Retirements of Generators:

- Age-Based Criteria for coal, natural gas, oils nukes, wind and solar
- Announced retirements.

## Additions of Generators:

- Announced

Distributed Energy Resources (DERs):  
Demand response, energy efficiency, and distributed generation.

Natural Gas Price Forecasting: MISO uses the Gas Pipeline Competition Model (GPCM) base price forecast across the three Futures.

Load: benchmarked load forecast with McKinsey.

Incentives: Inflation Reduction Act.

Resource Accreditation: based on the approved 2022 planning resource auction.

Battery Storage Assumptions

Electrification

Utility Announced Plans and IRPs



# Futures Assumptions Summary

Table 13 and Table 14 detail Future-specific input assumptions. Many of these variables were direct inputs to the model; however, selected DERs, retirements, and addition totals are results of the analysis.

## How “Factors” become “Inputs” into the Models

CAGR = compound annual growth rates  
 DG = distributed generation  
 DHW – heat pump water heaters  
 DR = demand response  
 EE = energy efficiency  
 HVAC = Heat Pumps  
 PEV = plug-in electric  
 C&I Process = electrification of industrial processes  
 RES = residential

Variables		Future 1A	Future 2A	Future 3A
Gross Load <sup>43</sup>	Low-Base EV Growth		30% Total Energy Growth by 2040	50% Total Energy Growth by 2040
	Total Growth	94,275 GWh	196,996 GWh	334,692 GWh
Energy (CAGR)	Input/Result	0.63% / 0.22%	1.25% / 0.80%	1.95% / 1.08%
Demand (CAGR)	Input/Result	0.77% / 0.36%	1.14% / 0.82%	1.63% / 1.14%
Electrification Growth & Technologies	Growth from Electrification	2% of Total Growth 14,147 GWh	15.2% of Total Growth 109,101 GWh	31.8% of Total Growth 231,513 GWh
Electrification Technologies	PEVs	PEVs	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW C&I-Process
Selected DERs	DR	10.8 GW	11.2 GW	11 GW
	EE	17.7 GW	17.7 GW	20.5 GW
	DG	19.9 GW	19.9 GW	20.5 GW
Carbon Reduction (2005 baseline)	MISO Footprint currently at 29%	71%	76%	80%
Wind & Solar Generation Percentage <sup>14</sup>		83% realized in results	96% realized in results	99% realized in results
Utility Announced Plans		Resulted in 55% with No Minimum Enforced	Resulted in 83% with No Minimum Enforced	87%
Utility Announced Plans		85% Goals Met 100% IRPs Met	100% Goals Met 100% IRPs Met	100% Goals Met 100% IRPs Met

Table 13: MISO Futures Assumptions

Source: [https://cdn.misoenergy.org/Series1A\\_Futures\\_Report630735.pdf](https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf)



# Order 1920/1920A – What are the Required Categories of Factors?

**Fundamental question:** what factors materially affect the need for transmission in 20 years?

## REQUIRED INPUTS TO SCENARIOS – CANNOT BE DISCOUNTED

- Federal, federally recognized tribal, state and local (“Governmental”) laws and regulations affecting the resource mix and demand;
- Governmental laws and regulations on decarbonization and electrification;
- State-approved IRPs and expected supply obligations for Load Serving Entities (LSEs);

## INPUTS TO SCENARIOS THAT MUST BE USED BUT CAN BE DISCOUNTED OR WEIGHTED

- Trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies;
- Resource retirements;
- GI requests and withdrawals;
- Utility ~~and corporate~~\*\* commitments and Governmental policy goals that affect transmission needs.

Providers may incorporate additional categories of factors in their Scenarios provided that each Scenario remains plausible.

# **MISO: Resource Expansion and Siting**

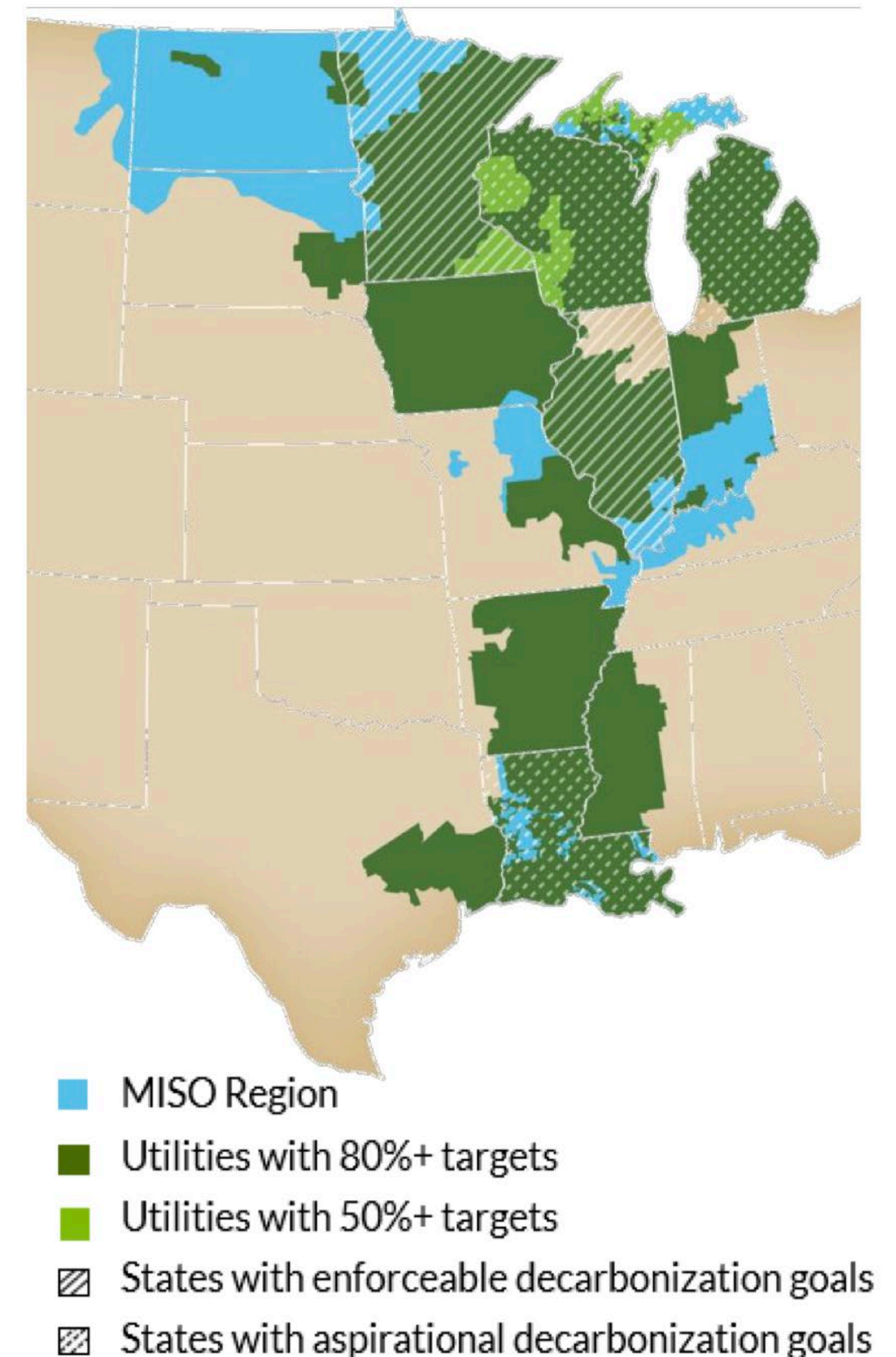


# Tranche 2.1 had a 96% reduction in carbon that was driven by member goals and economics.

1. 75% of MISO load served by members with ambitious decarbonization and/or renewable goals.
2. For Future 2A – though a 60% floor for decarbonization was assumed, the aggregation of member goals drove a 76% decarbonization model input.
3. When economic drivers were included, Future 2A had a total carbon reduction of 96%

Source:

<https://cdn.misoenergy.org/20231002%20LRTP%20Workshop%20Item%2003%20Sensitivities630348.pdf>

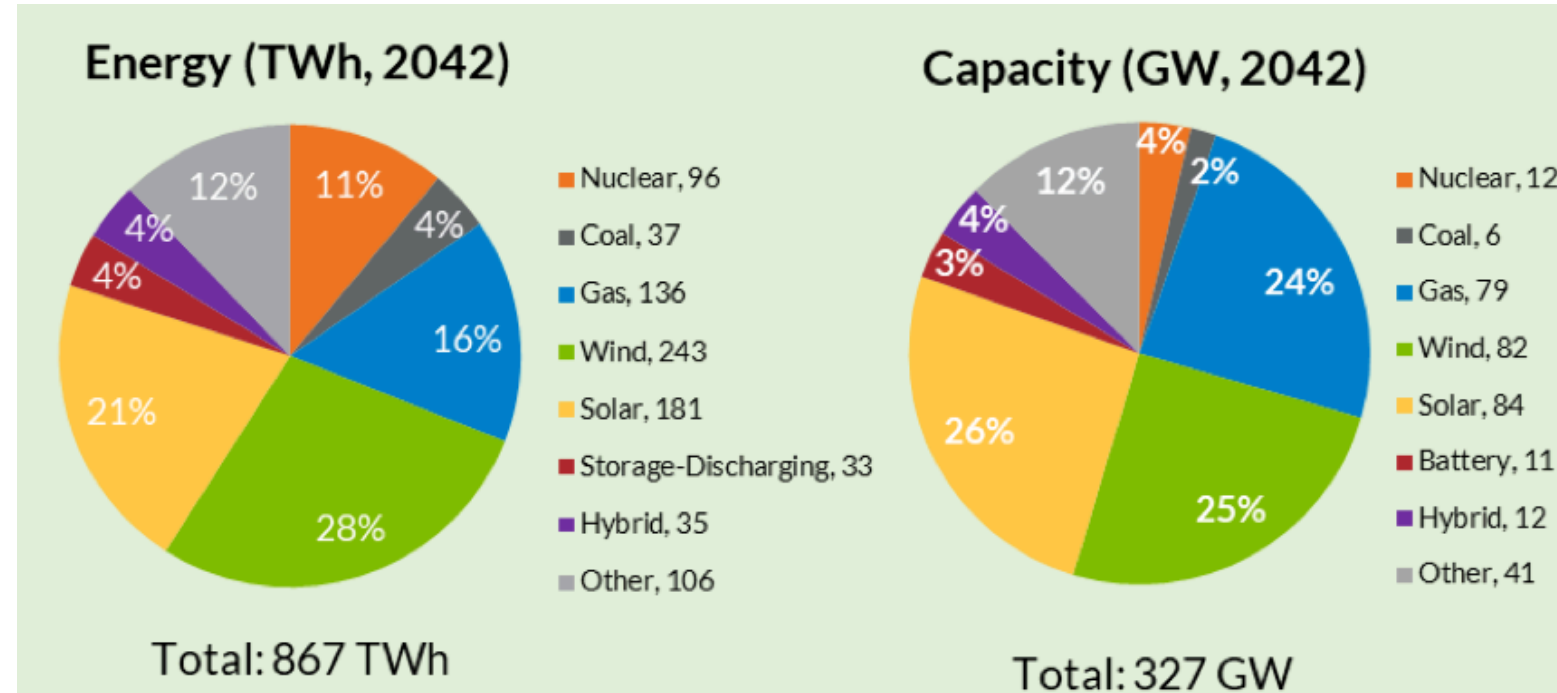


# Tranche 2.1 Resource Expansion Results

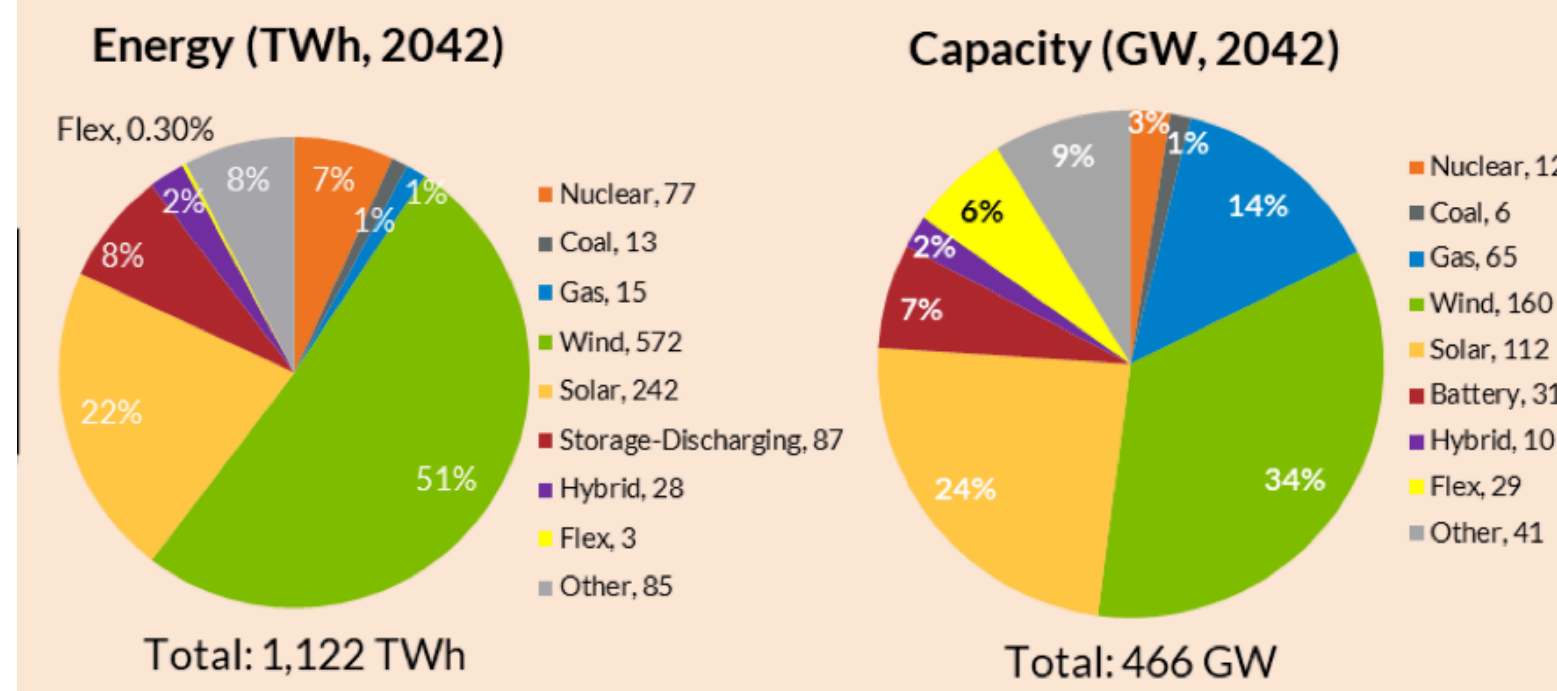
Source:  
[https://cdn.misoenergy.org/Series1A\\_Futures\\_Report630735.pdf](https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf)



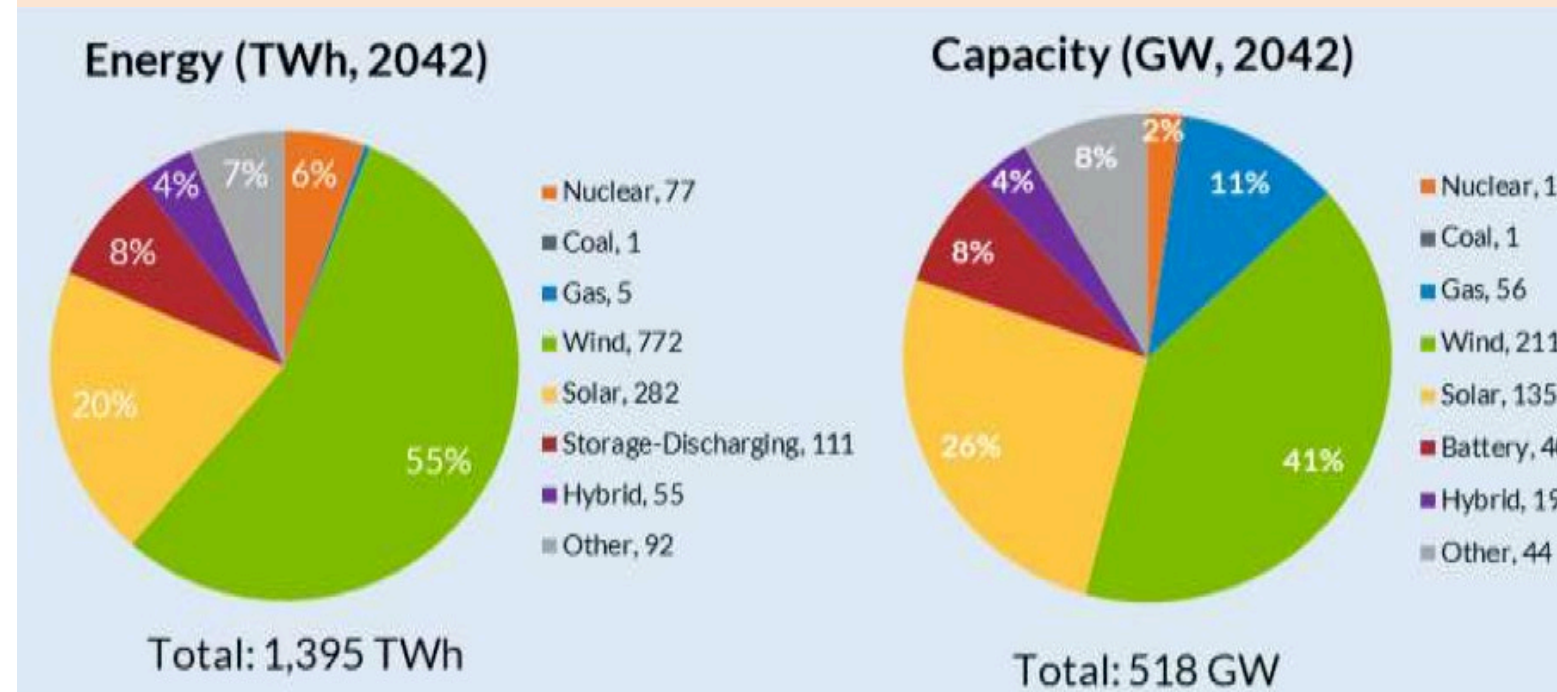
Future 1A



Future 2A



Future 3A



**Decarbonization**  
Input: 71%  
Results: 83%  
**Announced Plans**  
Goals Met: 85%  
IRPs: 100%  
**Forecast % Increase**  
Energy: 4.4%  
Demand: 7.5%  
**Compound Annual Growth Rates**  
Energy: 0.22%  
Demand: 0.36%

**Decarbonization**  
Input: 76%  
Results: 96%  
**Announced Plans**  
Goals Met: 100%  
IRPs: 100%  
**Forecast % Increase**  
Energy: 17.3%  
Demand: 17.6%  
**Compound Annual Growth Rates**  
Energy: 0.80%  
Demand: 0.82%

**Decarbonization**  
Input: 80%  
Results: 99%  
**Announced Plans**  
Goals Met: 100%  
IRPs: 100%  
**Forecast % Increase**  
Energy: 23.9%  
Demand: 25.3%  
**Compound Annual Growth Rates**  
Energy: 1.08%  
Demand: 1.14%

# Tranche 2.1 Siting Of Generators

Source:  
[https://cdn.misoenergy.org/Series1A\\_Futures\\_Report630735.pdf](https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf)

Future 2A: Planned Expansion

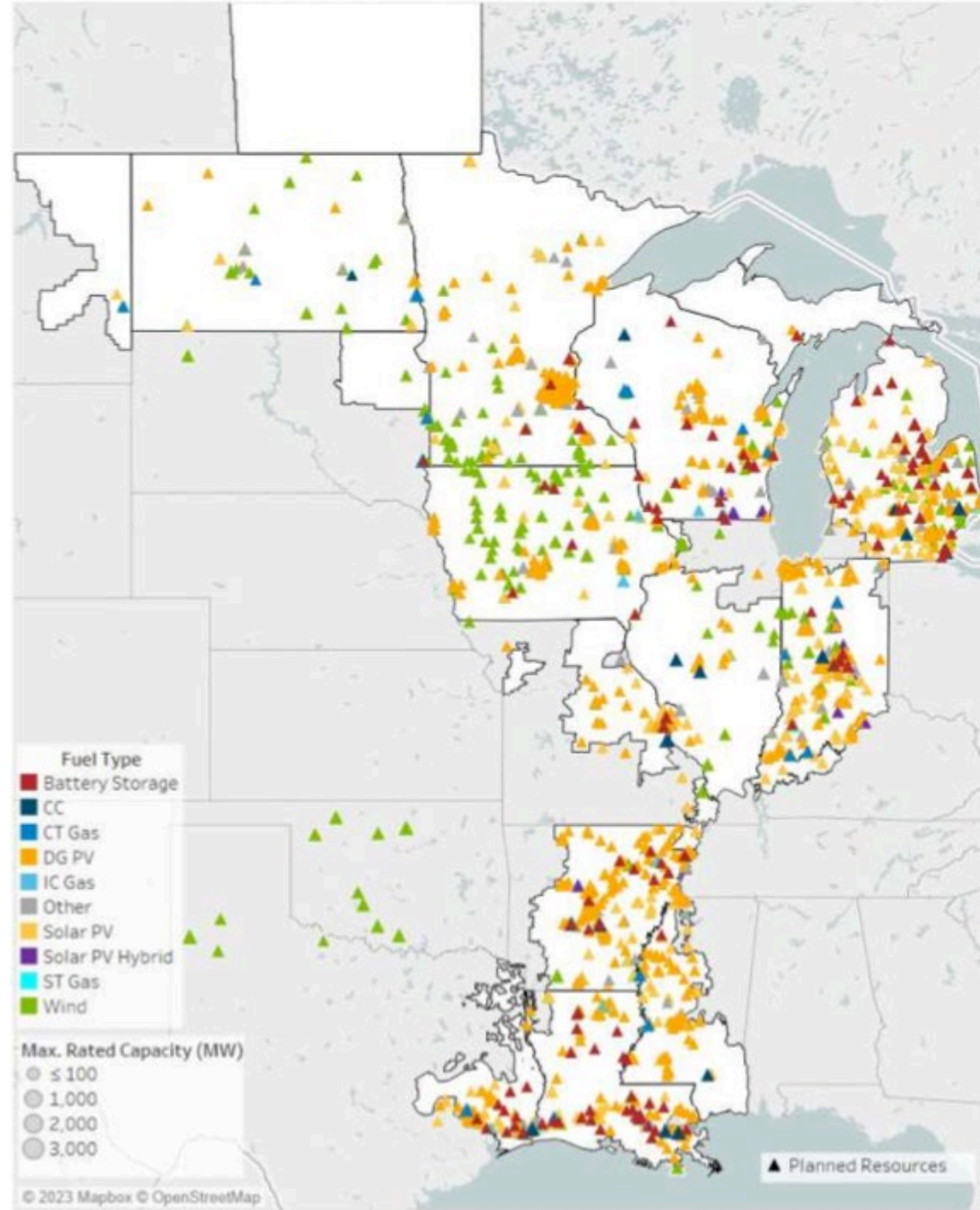


Figure 82: MISO Future 2A Non-EGEAS Expansion Siting

PRE-ORDAINED LOCATIONS FOR  
GENERATORS ALREADY PLANNED

Future 2A: Model-Built Expansion

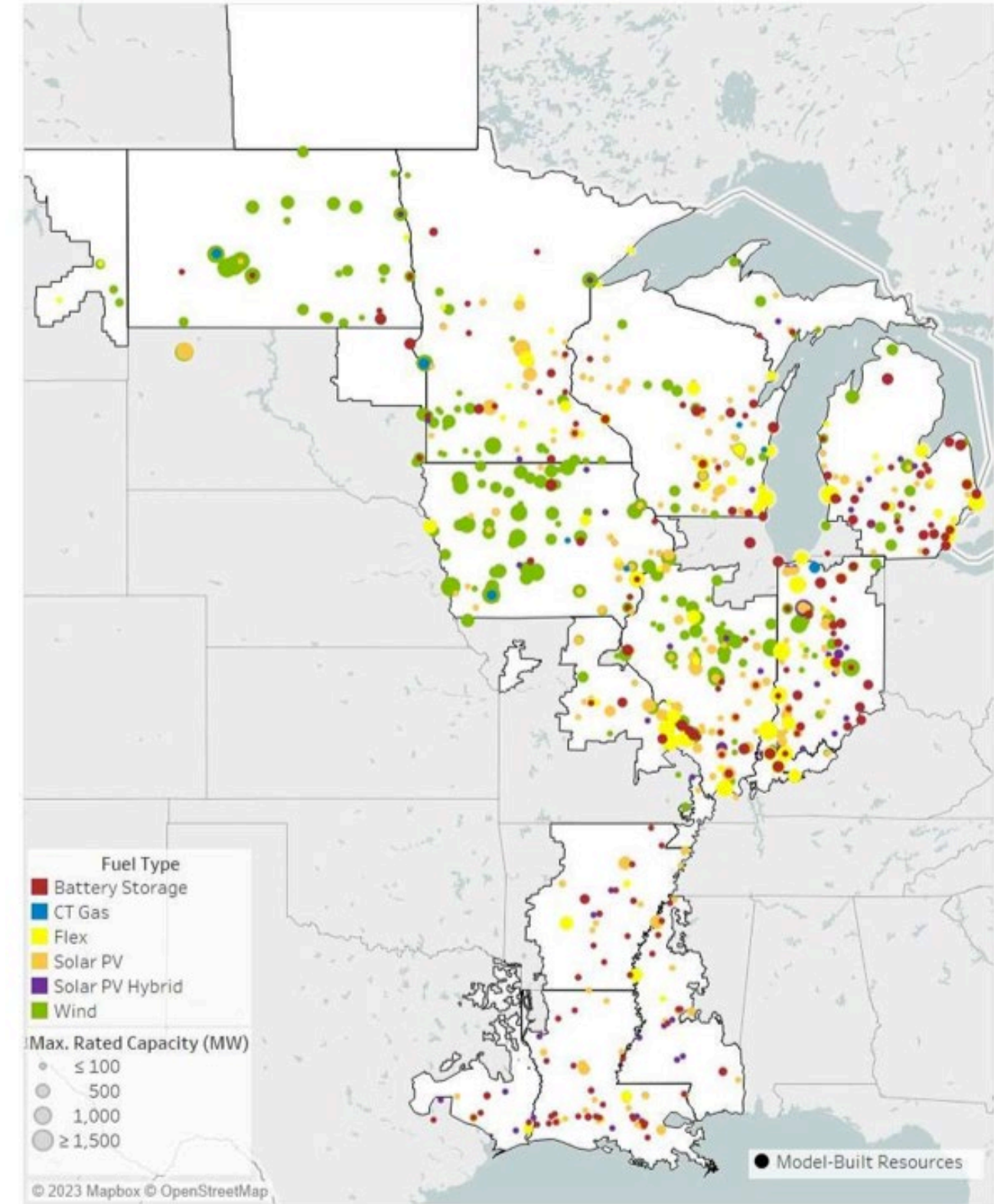


Figure 81: MISO Future 2A Complete EGEAS Expansion Siting

TPs MUST SELECT LOCATIONS FOR  
GENERATORS PICKED BY THE  
MODELS WITH INPUT FROM STATES  
AND UTILITIES

# **MISO: Identifying Needs, Potential Solutions and Developing Transmission Plans**



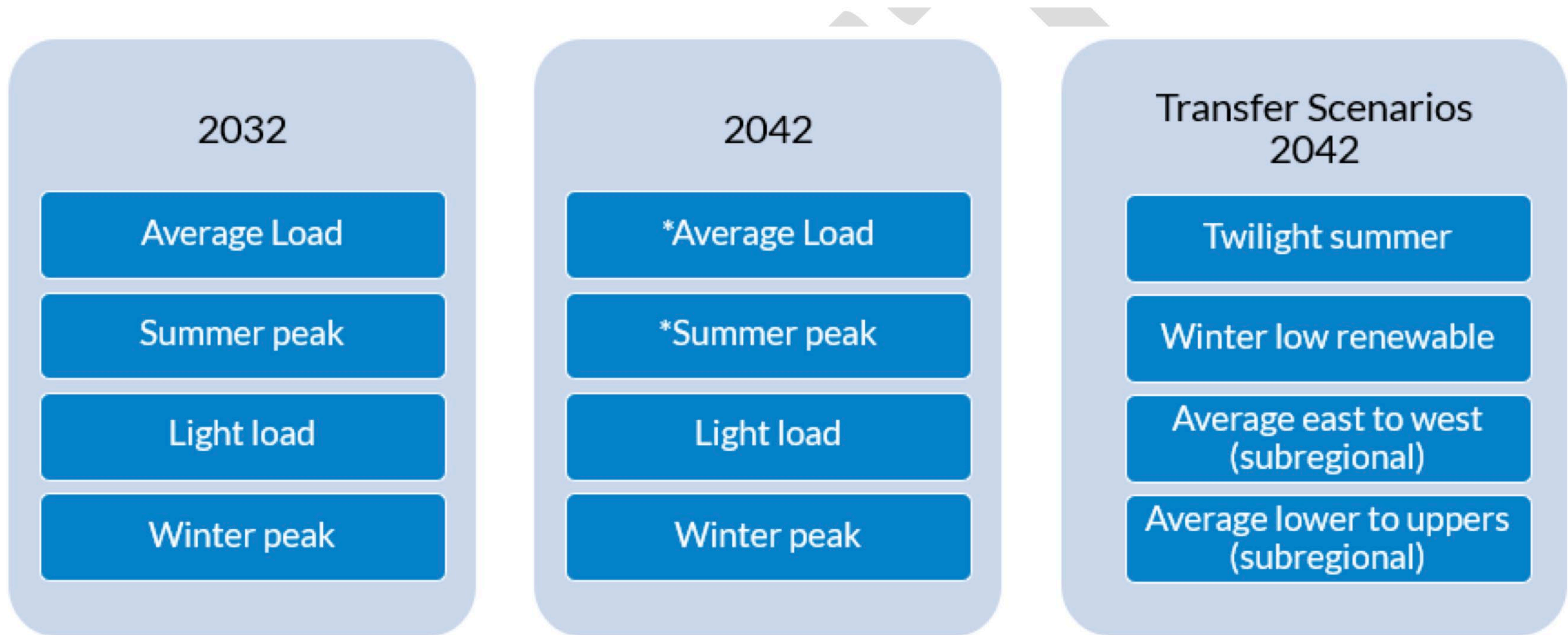
# Identifying Needs Through Reliability Modeling

Name	Description	Timeframe	Tools
<b>Steady-state</b>	Determines if transmission facilities remain within safe design limits (line loading and voltage) following disturbances	<ul style="list-style-type: none"> <li>• One operating point (instant)</li> <li>• 5+ min after a system disturbance</li> </ul>	Powerflow (PSS/E, TARA)
<b>Transient stability</b>	Determines if the system will experience uncontrolled loss of load or generation following disturbances; focus on voltage and frequency performance	<ul style="list-style-type: none"> <li>• 0-30 seconds following a system disturbance</li> </ul>	Dynamics (PSS/E, DSA)
<b>Transfer analysis</b>	Assesses impact of various system conditions, dispatch patterns and intra-regional power transfer limits; focus on line loading and voltages	<ul style="list-style-type: none"> <li>• One operating point (instant)</li> <li>• 5+ min after each change</li> </ul>	Transfer analysis (PSS/E, TARA)

Table 2.3: Description of reliability study components for LRTP 2.1 study



# Reliability Core Models



\* Models used for Dynamic assessment

Figure 2.8: Core Models used in Reliability Assessment



# Identifying Needs Through Economic Modeling

Source:  
<https://cdn.misoenergy.org/MISO%20Regional%20and%20Interregional%20Cost%20Allocation%20Reference90295.pdf>



Economic Metric Name	Description	Use
<b>Congestion Measure (\$/MW)</b>	An indication of the production cost savings opportunity from relieving transmission congestion	<ul style="list-style-type: none"> <li>Identifying most constrained transmission elements</li> <li>A reduction in Congestion Measure for a constraint or group of constraints indicates a more optimal regional dispatch</li> </ul>
<b>Curtailment (MWh)</b>	A measure of the total amount of energy from renewable sources which cannot be delivered economically	<ul style="list-style-type: none"> <li>Reduction of curtailment at a single generator improves that unit's financial viability</li> <li>Reduction of total curtailment in a region indicates that transmission investments enable additional renewable generation</li> </ul>
<b>Load LMP (\$/MWh)</b>	The Locational Marginal Price (LMP) is the market price to purchase energy from a market. Load Weighted LMPs are expressed as an average price weighted by energy each hour and at each delivery point and are indicative of the price of energy in a region	<ul style="list-style-type: none"> <li>A price separation in Load LMPs across a region indicates that transmission is limiting efficient dispatch, resulting in overall higher production costs</li> </ul>
<b>Adjusted Production Cost (APC) (\$)</b>	A measure, by company, of the costs to serve demand, considering the effect of purchase and sales	<ul style="list-style-type: none"> <li>Evaluating the combined measure of the operating cost of companies within MISO</li> </ul>
<b>Adjusted Production Cost Savings (\$)</b>	APC Savings are seen when APC decreases from one model to another (i.e., Reference Case – Change Case). A company sees APC Savings when they dispatch lower cost generation, purchase power at a lower load LMP, or sell power at a higher Gen LMP	<ul style="list-style-type: none"> <li>Evaluating portfolio benefits in the Business Case</li> </ul>
<b>Generation Enablement (MW)</b>	A Distribution Factor (DFAX) based methodology to determine which Future Series Model Built resources are enabled by regional transmission to connect to the system	<ul style="list-style-type: none"> <li>Future Series Model Built resources with <math>\geq 5\%</math> DFAX are considered enabled</li> </ul>

Table 2.4: Economic Metrics

# Iterate Between Reliability and Economic Analyses to Identify Needs and to Evaluate and Select Solutions

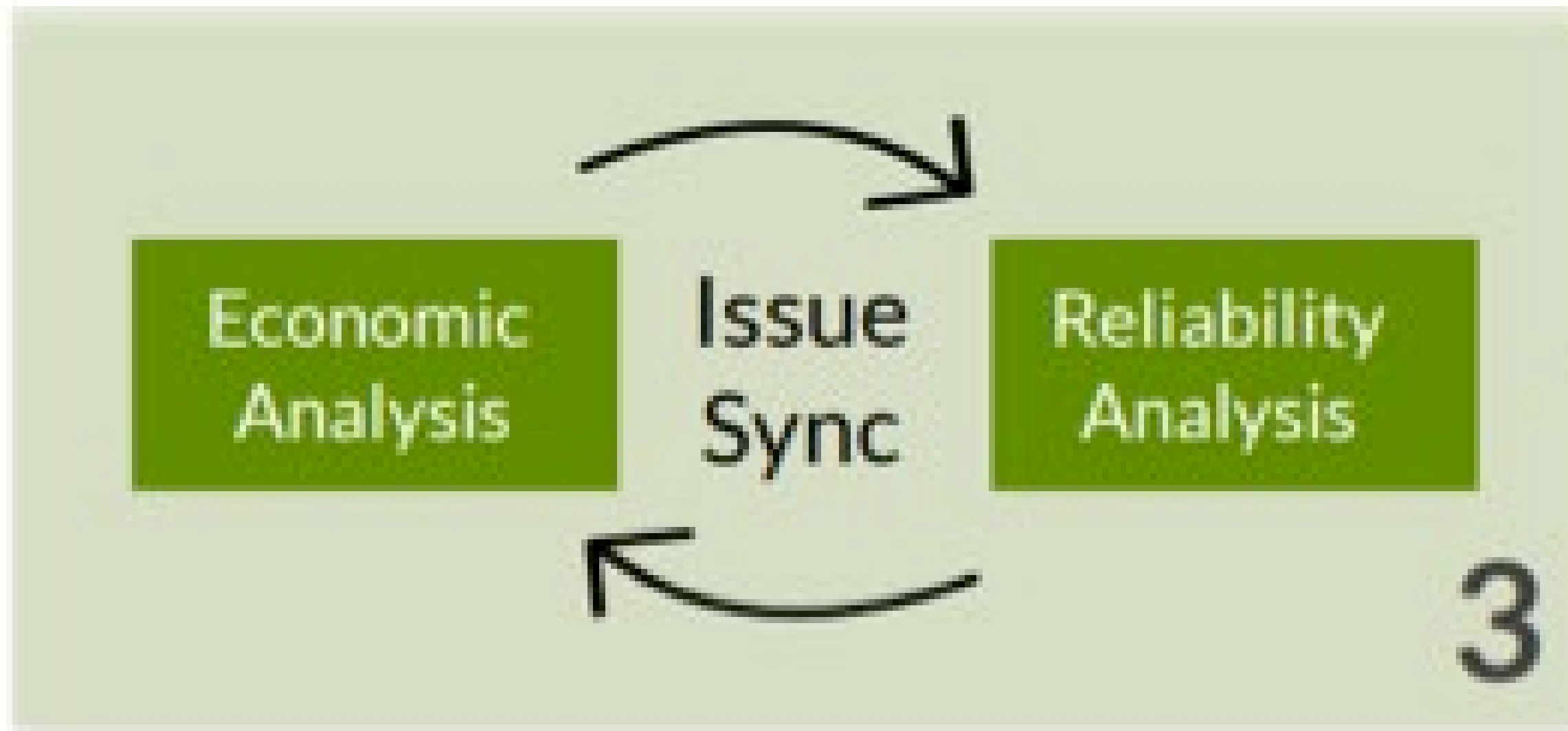
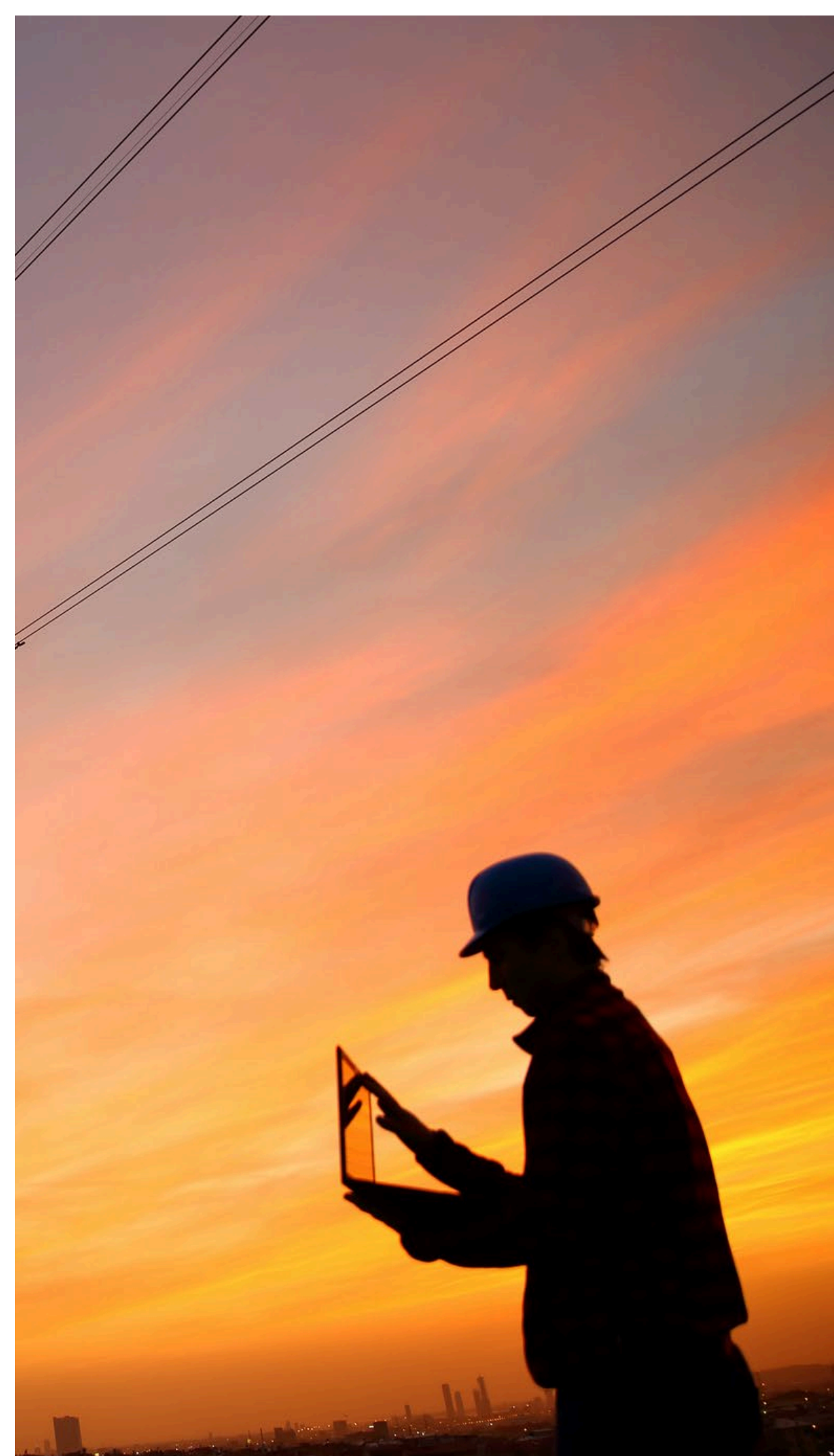


Figure 2.18.



# Examples of Other Factors Considered During the Evaluation and Selection Process

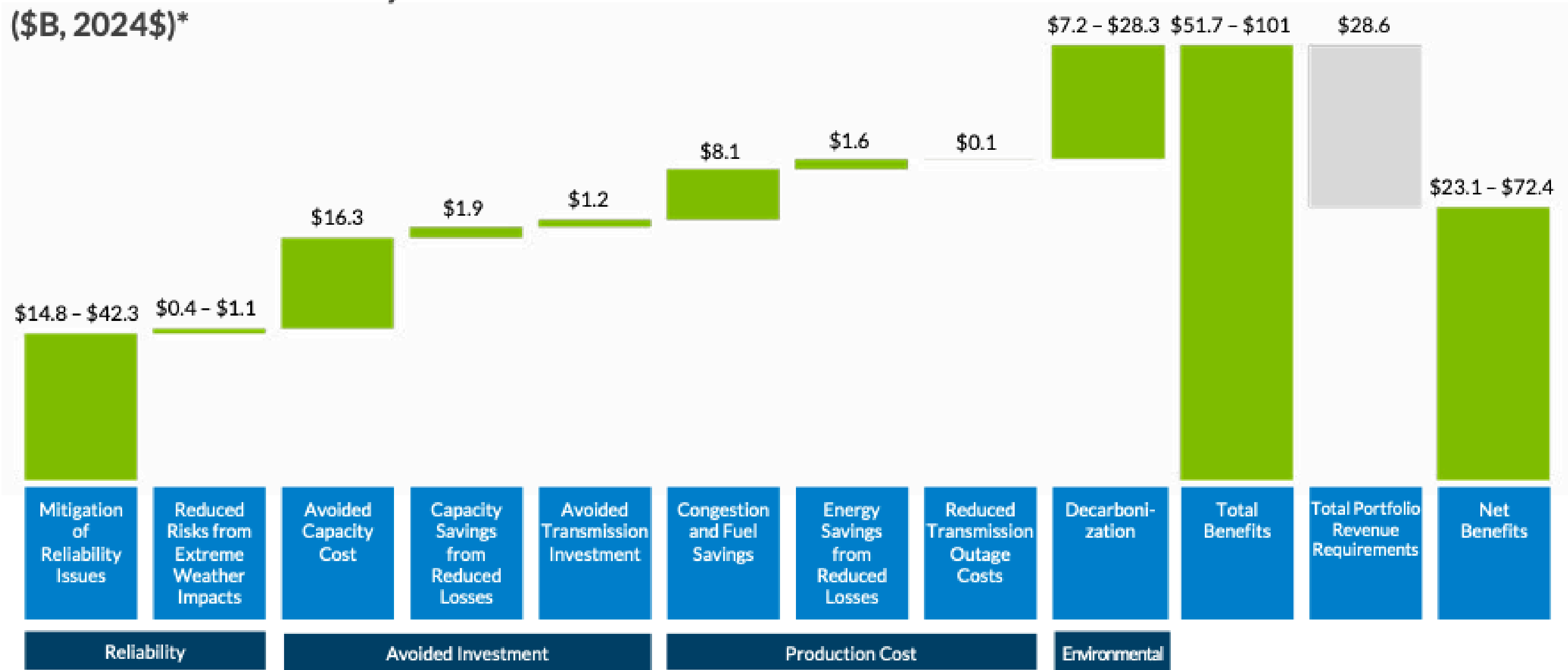
- Ability to co-locate with existing infrastructure
- The amount of right-of-way (ROW) needed
- Legacy voltage vs. Changing voltage
- Permit-ability
- “Robustness testing” – includes sensitivities
  - Projects that were approved or in the process of approval after power flow models were completed
  - Assess with and without key projects
- Right-sizing opportunities



# MISO Calculates 20-year B/C Ratio for Portfolio

**L RTP Benefits vs. Cost**  
*Based on Future 2A - 20 yr Present Value*  
 (\$B, 2024\$)\*

**F2A Total benefit/cost ratio ranges from 1.8 to 3.5**



\*Estimated costs as of 9/24/2024. Assumes 7.1% discount rate. Benefit ranges reflect changes in assumptions for the value of lost load (mitigation of reliability issues/extreme weather impacts) and carbon reduction values (decarbonization). Additional details on the methodology for each L RTP Tranche 2.1 metric available in whitepaper.

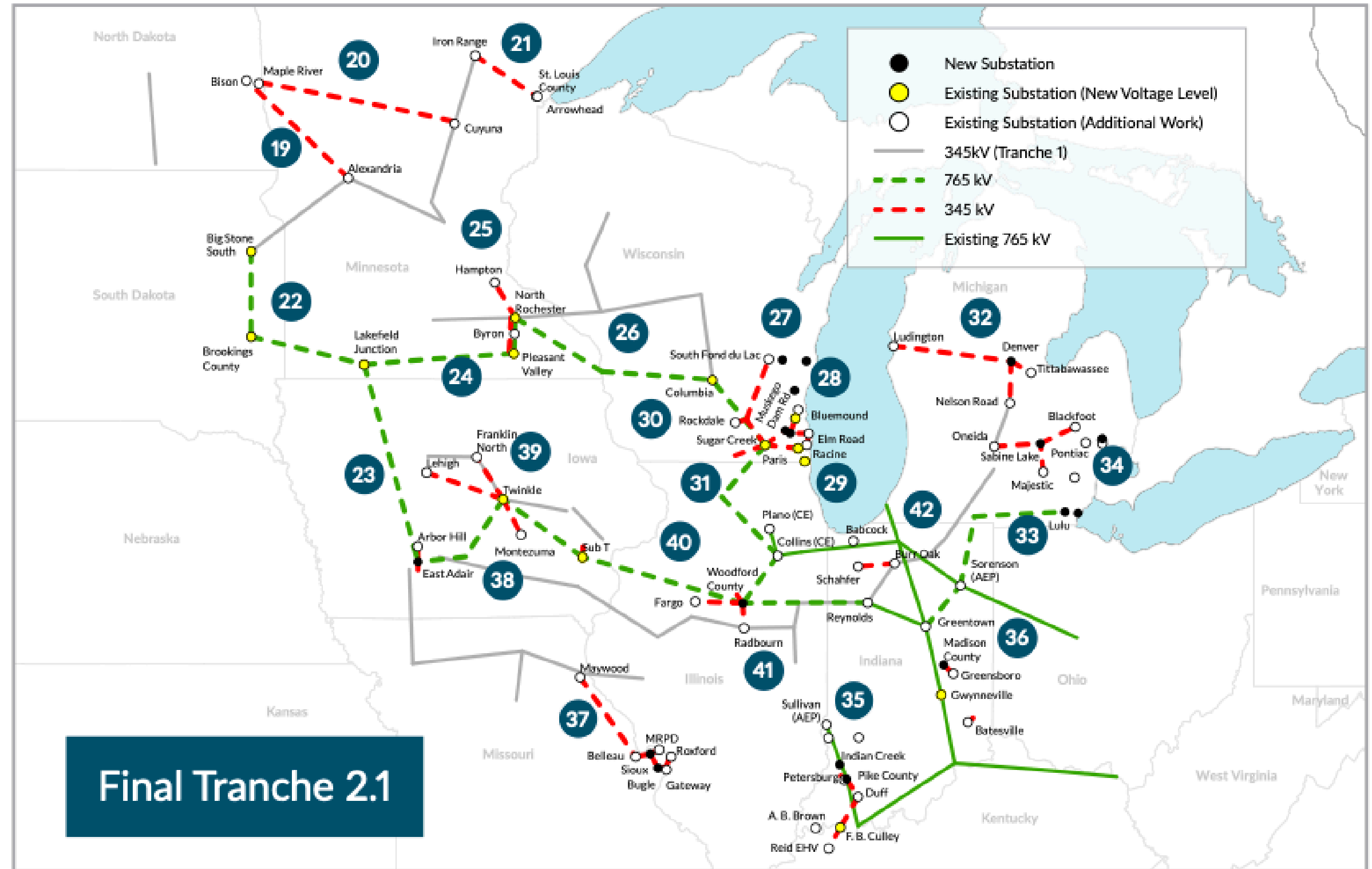


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Source: <https://cdn.misoenergy.org/MTEP24%20Executive%20Summary658126.pdf>

See also: <https://cdn.misoenergy.org/MTEP24%20Chapter%202%20-%20Regional%20Long%20Range%20Transmission%20Planning658124.pdf>

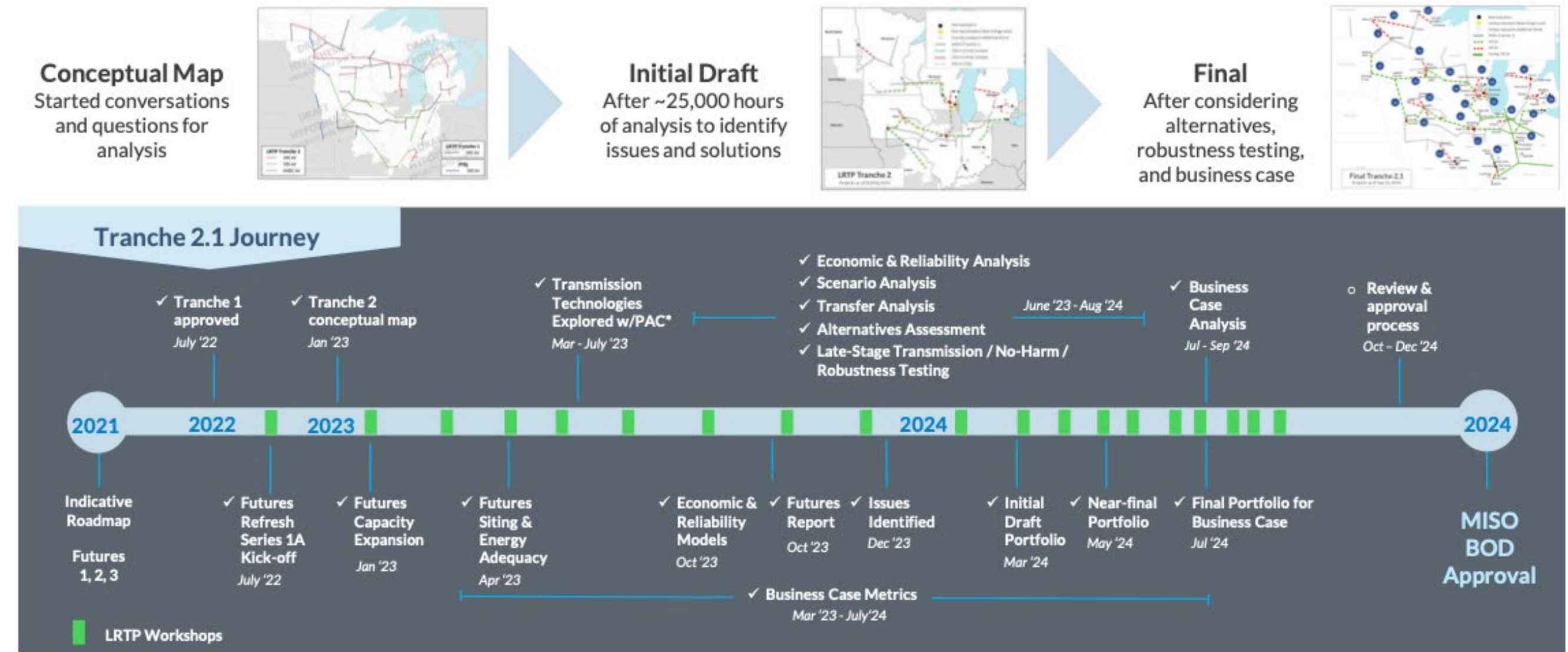
The Tranche 2.1 portfolio includes 24 projects and 323 facilities across the MISO Midwest subregion



# Tranche 2.1 Final Transmission Plan based on Future 2A

The Tranche 2.1 journey began in 2022 and has involved more than 40,000 hours of labor from MISO staff, 300 formal meetings, and numerous discussions with stakeholders

# One Planning Cycle Takes Years



\*PAC = Planning Advisory Committee



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# Order 1920 Evaluation Processes including Selection Criteria

## Evaluation Processes Must:

1. Identify one or more Facilities (or a portfolio) that address the Needs;
2. Estimate the costs and measure the benefits of Facilities that are identified or proposed for potential selection;
3. Select or don't select Facilities including determinations that are sufficiently detailed explain why a particular Facility (or portfolio) was selected or not selected. O1920 ¶ 955.

## Evaluation and Selection Criteria Must:

1. Be transparent and not unduly discriminatory;
2. Aim to ensure that more efficient or cost-effective Facilities are selected to address Needs – TPs have flexibility in how they measure efficiency and cost effectiveness; including by using
  - a. Benefit-to-cost ratios (cannot be higher than 1.25),
  - b. assessing their net benefits, and/or
  - c. using some other method.
3. Seek to maximize benefits accounting for costs over time without over-building transmission facilities. O1920 ¶ 958.

# **Scenario Planning – How RSEs can Influence Order 1920/1920A Regional Scenario Planning**



# Order 1920A Increases State Input on Regional Planning

Engagement Period – can be extended from 6 months up to 1 year if needed.

## Factors, Scenarios and Inputs:

- states must have a “meaningful opportunity to provide timely input” on Scenarios development, including factors and data inputs, and to explain how their own policies and planning affect Needs. O1920A ¶ 344.
- when determining the assumptions for scenarios, TPs must “consult with and consider” RSEs’ positions on factors related to states’ laws, policies, and regulations. O1920A ¶ 271.
- TPs “shall consult” with RSEs as to:
  1. whether a specific state policy must be accounted for as a factor within each category (i.e., if the specific state policy will likely affect Needs),
  2. how to account for the specific state policy in the development of Scenarios (e.g., the method and data used to forecast generation resources added because of a specific state policy), and
  3. how to adjust the treatment of the specific state policy across Scenarios (e.g., assume certain policy-related outcomes materialize in some but not all Scenarios). O1920A ¶ 344.
- for states with IRPs, TPs should include one of the state’s preferred power system trajectories, including both the supply and demand side resource trajectory as appropriate. O1920A ¶ 275.

## Evaluation and Selection Criteria:

- TPs must make “good faith efforts to consult with and seek support” from RSEs on the evaluation processes and selection criteria. O1920A ¶ 460.
- TPs are “encouraged” to consider any selection criteria supported by RSEs. O1920A ¶ 459.



**The Engagement Period is  
a Significant Opportunity  
for States to Influence  
Their Future**

**...Start Now**



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**Thank you!**

**For additional assistance and technical support,  
please contact  
Great Plains Institute & Azar Law LLC**

Lauren Azar  
Azar Law LLC  
[Lauren@azarlawllc.com](mailto:Lauren@azarlawllc.com)

Matt Prorok  
Policy Director,  
Great Plains Institute  
[mprorok@gpisd.net](mailto:mprorok@gpisd.net)

