



Modeling the Order 1920 Benefit Metrics: A review of regional transmission planning best practices

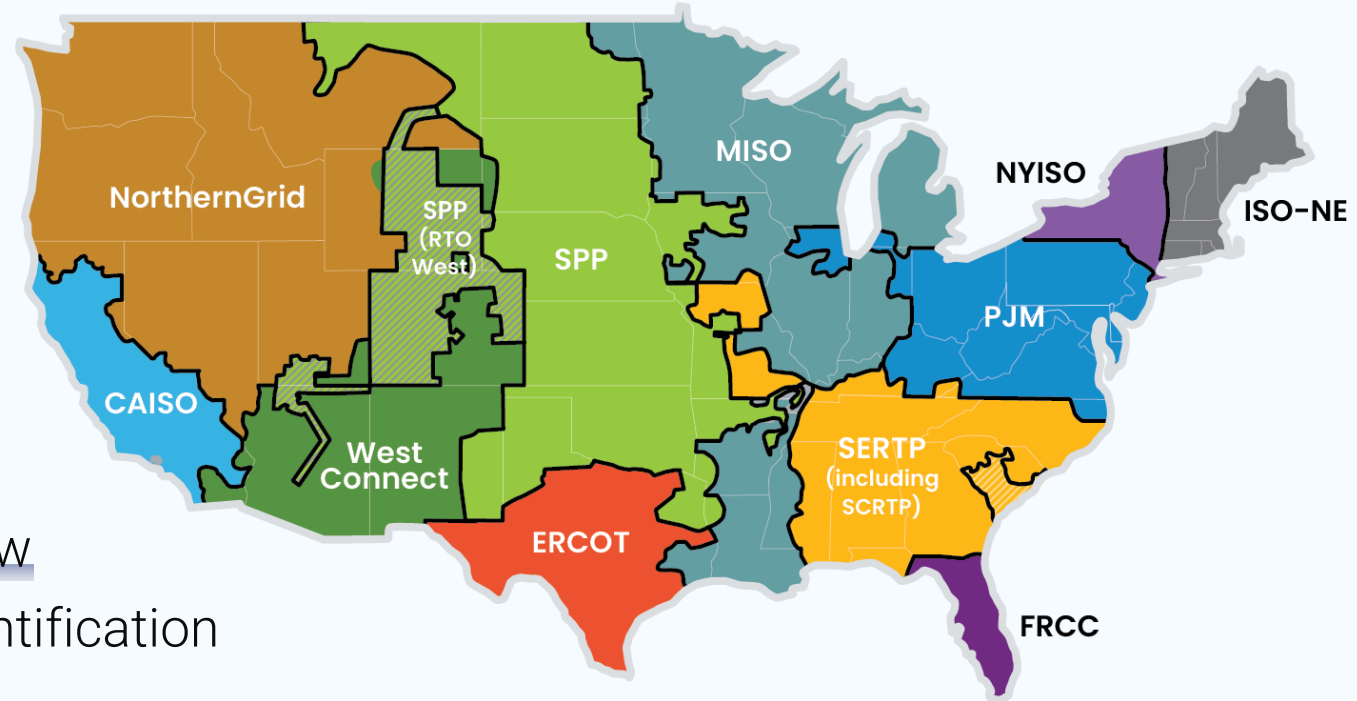
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Prepared for the Connected Grid Initiative

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Report overview

- This report
 - describes benefit evaluation and the required Order 1920 benefit metrics,
 - discusses important considerations for transmission benefit quantification,
 - presents a suggested methodology for defining and evaluating each metric,
 - assesses all regional planners' existing and proposed benefit evaluation practices,
 - discusses the implications of different methodological choices, and
 - identifies several common challenges when evaluating benefits.
- A subsequent report will demonstrate the suggested benefit evaluation methodology on a mock portfolio of high-capacity transmission lines.
- Acronyms, definitions, and references can be found in the report Appendices.

Background on FERC Order No. 1920

Focus of this report

FERC Order 1920 is a landmark rule requiring long-term, proactive regional transmission planning to meet future energy needs. Major elements of the rule include:

- Long-Term Planning: Transmission providers must conduct comprehensive 20-year planning.
- Scenario-Based Planning: Long-term plans must be based on at least three plausible future scenarios.
- Grid Modernization: Includes "right-sizing" of existing facilities and consideration of advanced transmission technologies to improve system capacity.
- Benefit Evaluation: Candidate transmission solutions must be evaluated using seven specific metrics.
- Project Selection: Candidate projects selected for inclusion in long-term plans must be based on the combined total of all seven benefits ("multi-value planning"). Evaluation can occur on an individual or a portfolio of projects basis, but selected solutions must have a benefit-to-cost ratio between 1.0 and 1.25 in either case.
- Cost Allocation: The order requires negotiated methods for paying for new transmission, including with input from state entities. The benefits required for evaluating candidate are not required to be used in cost allocation, and many regional planners are not proposing to use them.

Most of the planning requirements in Order 1920 do not apply to near-term, 10-year transmission plans already conducted by regional planners.

Executive Summary

Order 1920 requires planners to evaluate transmission using specific benefit metrics, metrics that are unfamiliar to some.

Here we detail the best practices to employ the benefit evaluation requirements of Order 1920.

- High-capacity transmission provides many benefits. But without proper evaluation of these benefits, cost-saving solutions to future system needs may be missed during transmission planning.
- Order 1920 requires regional transmission planners to adopt multi-value planning by evaluating candidate transmission solutions across seven specific benefit metrics. This will require all regional planners to modify their existing evaluation methods, either in whole or part.
- Neither multi-value transmission planning nor the specific benefit metrics required by Order 1920 are new. Some regional planners already use one or both in their existing near-term system plans, although few regional planners apply them in a comprehensive way. We can learn from these existing practices.
- The models used in project evaluation can greatly impact the benefit evaluation results. Regional planners must be sure they are using appropriate modeling tools and assumptions.
- While Order 1920 provides requirements and basic guidelines for how to evaluate benefits, the devil is always in the details. Through a review of existing and proposed practices, we have identified a set of best practices that would improve benefit evaluation.

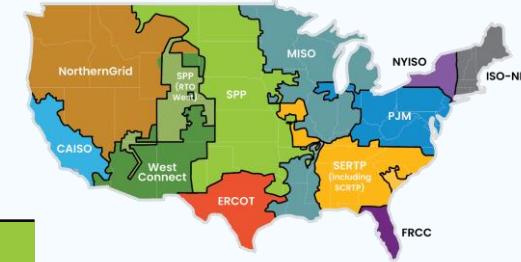
Finding 1: The required Order 1920 benefits are currently considered by some, but not all, regional planners in their existing near-term transmission evaluation processes.

| Benefits of high-capacity regional transmission | Percentage of regional planners which currently consider benefit | Corresponding O1920 Number |
|--|--|----------------------------|
| Increases access to lower-cost generation during <u>typical</u> conditions | 82% | 3 |
| Increases access to lower-cost generation during <u>contingency</u> conditions | 36% | 5 |
| Increases access to lower-cost generation during <u>stress</u> conditions | 23% | 6 |
| Decreases transmission system losses elsewhere in the system | 73% | 4 |
| | 27% | 7 |
| Requires fewer generators to maintain resource adequacy | 45% | 2(b) |
| Lessens the severity of <u>resource adequacy</u> events | 27% | 2(a) |
| Lessens the severity of <u>resiliency</u> events | 23% | 6 |
| Offsets the need for new or refurbished local transmission facilities | 82% | 1 |
| Other | 45% | 8 |

Finding 2: Even though many regional planners consider multiple metrics in benefits evaluation, they are not all aligned with Order 1920. Still, they can be used to determine best practices.

Existing benefits evaluation: ● Benefit present & aligned ◐ Benefit present but not fully aligned ○ Benefit absent

***Proposed O1920 benefits:** ■ Methodology developed & likely aligned ◑ Developed but not fully aligned □ Not yet developed



| FERC Order 1920 | | CAISO | | NorthernGrid | | WestConnect | | ERCOT | | SPP | |
|-----------------|---|---------|------|--------------|------|-------------|------|---------|------|---------|------|
| No. | Benefit | Current | Plan | Current | Plan | Current | Plan | Current | Plan | Current | Plan |
| 1 | Avoided or deferred reliability facilities and aging infrastructure replacement | ● | ■ | ● | □ | ◐ | □ | ○ | N/A | ◐ | ■ |
| 2 | Reduced costs related to resource adequacy | ◐ | ◑ | ○ | ■ | ◐ | ◑ | ○ | N/A | ○ | ■ |
| 3 | Production cost savings | ● | ■ | ◐ | ■ | ● | ◑ | ● | N/A | ● | ■ |
| 4 | Reduced transmission energy losses | ● | ■ | ◐ | ■ | ○ | ◑ | ◐ | N/A | ● | ■ |
| 5 | Reduced congestion due to transmission outages | ◐ | ■ | ○ | ■ | ○ | ◑ | ◐ | N/A | ● | ■ |
| 6 | Mitigation of extreme weather events and unexpected system conditions | ○ | ◑ | ○ | ◑ | ○ | ◑ | ○ | N/A | ○ | ■ |
| 7 | Capacity cost benefits from reduced peak energy losses | ● | ■ | ○ | □ | ○ | □ | ○ | N/A | ● | ■ |

*Many planners have considered benefit methodologies in more detail than the minimum required for inclusion in their tariff, while others are waiting until their Business Practice Manual is developed. Judgement on alignment is based on available descriptions to date.

Finding 2: Even though many regional planners consider multiple metrics in benefits evaluation, they are not all aligned with Order 1920. Still, they can be used to determine best practices.

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| FERC Order 1920 | | MISO | | FRCC | | SERTP/SCRIPT | | PJM | | NYISO | | ISO-NE | |
|-----------------|---|---------|------|---------|------|--------------|------|---------|------|---------|------|---------|------|
| No. | Benefit | Current | Plan | Current | Plan | Current | Plan | Current | Plan | Current | Plan | Current | Plan |
| 1 | Avoided or deferred reliability facilities and aging infrastructure replacement | ● | ■ | ● | □ | ● | ◻ | ○ | □ | ◐ | □ | ● | □ |
| 2 | Reduced costs related to resource adequacy | ● | ■ | ○ | □ | ○ | ■ | ● | □ | ● | □ | ● | □ |
| 3 | Production cost savings | ● | ■ | ○ | □ | ○ | ◻ | ● | ■ | ● | □ | ● | □ |
| 4 | Reduced transmission energy losses | ● | ■ | ● | □ | ● | ■ | ○ | ■ | ○ | □ | ● | □ |
| 5 | Reduced congestion due to transmission outages | ● | ■ | ○ | □ | ○ | ■ | ○ | ■ | ○ | □ | ○ | □ |
| 6 | Mitigation of extreme weather events and unexpected system conditions | ◐ | □ | ○ | □ | ○ | ■ | ○ | □ | ◐ | □ | ○ | □ |
| 7 | Capacity cost benefits from reduced peak energy losses | ● | ■ | ○ | □ | ○ | ■ | ○ | □ | ○ | □ | ○ | □ |

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Finding 3: There are many important modeling considerations that must be decided when establishing the full planning process. These choices will impact final benefits evaluation and selection.

- Benefit evaluation based on multiple plausible and diverse scenarios of the future power system is more likely to capture transmission benefits than if calculated using only a single scenario.
- The choice of future generation and transmission characteristics used in the base case will impact how the total transmission value is spread across multiple benefits.
- Portfolio-based benefit evaluation—rather than evaluating each facility individually—will result in the most efficient facilities being selected as solutions. Portfolio-based benefit evaluation should be used in project selection as a cost-saving measure for ratepayers.
- Modeling the benefits across multiple future years will enable a better comparison of candidate transmission solutions, especially given different development timelines for different transmission facilities.
- Benefits should be calculated using the net projected value over the depreciation life of the transmission assets and using consistent financial data (e.g., discount rates) with other internal evaluation processes.

Finding 4: A review of best practices leads to the following methods for evaluating the required Order 1920 benefits.

| ORDER 1920 BENEFIT | DESCRIPTION | METHOD (DELTA of TWO SCENARIOS) | MONETIZATION (NPV) |
|--|---|--|---|
| 1 Avoided or deferred reliability transmission facilities and aging infrastructure replacement | Reduced costs achieved by delaying or avoiding transmission facility additions / upgrades to address near-term reliability needs and replace aging infrastructure. | Identify planned transmission facilities—as determined by local utilities—that are deferred or avoided from the candidate facility AND Difference in future thermal overloads between base and change cases | Transmission capex [\$] of avoided facility additions / upgrades AND Proxy costs for transmission facilities to overcome thermal overloads |
| 2 Reduced costs related to resource adequacy | Enhanced power system reliability from either a) reducing unserved energy, or b) reducing generation needed to maintain loss of load expectation. | a) Difference in unserved load between base and change cases OR b) Difference in generation capacity needed to meet planning reserve margin requirements between base and change cases | a) Avoided unserved load [MWh] x value of lost load [\$/MWh] OR b) Avoided cost of new entry [\$/kW-yr] x generation [MW] |
| 3 Production cost savings | Reduced cost of generating electricity by using less expensive power—now accessible by larger transmission network—to meet demand. | Difference in production costs between base and change cases (ignoring transmission losses) under typical conditions | Avoided production costs [\$] |
| 4 Reduced transmission energy losses | Reduced energy losses across transmission facilities when moving power from supply sources to load centers. | Difference in production costs between base and change cases (for only transmission losses) under typical conditions OR Difference in transmission losses between base and change cases, calculated using known electrical parameters and expected power flow | Avoided production costs [\$] OR Avoided losses [MWh] x shadow node price [\$/MWh] |
| 5 Reduced congestion due to transmission outages | Reduced cost of generating electricity resulting from avoided congestion during transmission outages. Increased transmission capacity reduces overall congestion on the system. | Difference in production costs between base and change cases (including transmission losses) under contingency conditions | Avoided production costs [\$] |
| 6 Mitigation of extreme weather events and unexpected system conditions | Reduced cost of generating electricity and loss of load during extreme weather events and unexpected system conditions, including the value of interregional transfer capability. | Difference in production costs between base and change cases (including transmission losses) under stress conditions AND Difference in unserved load between base and change cases under stress conditions | Avoided production costs [\$] AND Avoided unserved load [MWh] x value of lost load [\$/MWh] |
| 7 Capacity cost benefits from reduced peak energy losses | Reduced generation capacity investments needed given reduced transmission losses to serve peak demand. | Difference in generation capacity needed to make up system transmission losses during peak demand hour between the base and change cases | Avoided cost of new entry [\$/kW-yr] x peak hour losses [MW] |

Finding 5: There are many challenges to good benefits evaluations. These challenges can be overcome if considered early when developing benefit evaluation methodologies.

Common challenges

1. Modeling complexity of benefit evaluation methodologies
2. Avoiding double counting across numerous benefit metrics
3. Consistent data and benefit quantification methods with neighboring regional planners
4. Monetization of often unmonetized benefits, such as reduced unserved energy
5. Siloed planning processes leading to inconsistencies across planning functions

Potential solutions

1. Only increase complexity if it impacts results needed for decision making
2. Allocate benefits from as few modeling runs as possible, rather than subtracting duplicative benefits from multiple runs
3. Align models, inputs, assumptions, and benefit quantification methods with neighboring planning regions early
4. Decisions on benefit monetization should be made early via stakeholder engagement, ahead of the evaluation process
5. Coordination and interdependent model assumptions should be used across the regional planning organization to ensure consistent planning

Transmission Benefits Evaluation Overview

High-capacity transmission provides many benefits to ratepayers.

Until Order 1920, regional planners did not uniformly measure these benefits when evaluating future transmission solutions.

The transmission planning process consists of:



- Order 1920 requires all regional planners to modify each step of the above processes. While **Step 4 is the focus of this report**, best practices should be followed for all other Steps. Otherwise, it is possible to plan too little or too much transmission to meet future system needs – and either of those outcomes risk unnecessary costs being passed on to ratepayers. Some best practices for other Steps are discussed in the Considerations section.
- Order 1920 requires all regional planners to evaluate potential future transmission solutions using seven benefit metrics in their long-term, 20-year plans.
- Neither multi-value transmission planning nor the specific benefit metrics required by Order 1920 are new. Some regional planners already use one or both in their existing near-term system plans. We can learn from these existing practices.

Order 1920 requires all regional planners to evaluate candidate transmission solutions using a standard set of benefits.

A *simplified* list of the required benefits and their intended measurement methods are below.

| Benefits of high-capacity regional transmission | Measured as | Corresponding O1920 Number |
|--|-----------------------|----------------------------|
| Increases access to lower-cost generation during <u>typical</u> conditions | Generation Production | 3 |
| Increases access to lower-cost generation during <u>contingency</u> conditions | | 5 |
| Increases access to lower-cost generation during <u>stress</u> conditions | | 6 |
| Decreases transmission system losses elsewhere in the system | Generation Capacity | 4 |
| Requires fewer generators to maintain resource adequacy | | 7 |
| Lessens the severity of <u>resource adequacy</u> events | Unserved Energy | 2(b) |
| Lessens the severity of <u>resiliency</u> events | | 2(a) |
| Offsets the need for new or refurbished local transmission facilities | Transmission Capacity | 6 |
| | | 1 |

both required by Order
either

The required Order 1920 benefits are currently considered by many, but not all, regional planners in their Order 1000 transmission evaluation.

| Benefits of high-capacity regional transmission | Percentage of regional planners which currently consider benefit | Corresponding O1920 Number |
|--|--|----------------------------|
| Increases access to lower-cost generation during <u>typical</u> conditions | 82% | 3 |
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| Requires fewer generators to maintain resource adequacy | 45% | 2(b) |
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| Offsets the need for new or refurbished local transmission facilities | 82% | 1 |
| Other | 45% | [8] |

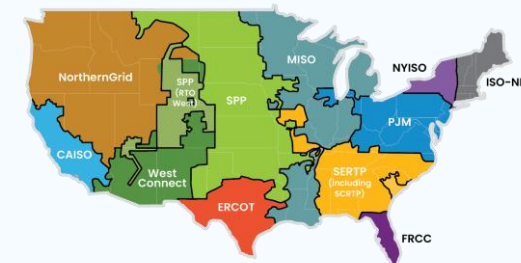
While all regional planners have existing benefit metrics for evaluating near-term transmission plans, each is in a different development stage for their long-term benefit metrics.

Regional planners are currently in the process of revising their tariffs to meet the requirements of Order 1920, including a high-level description of the benefit metrics used to evaluate candidate transmission solutions. **However, the details of how these metrics are defined are usually reserved for Business Practice Manuals, which do not need FERC approval and will not be fully updated until after tariff revisions are completed and approved by FERC.**

Many planners have considered benefit methodologies in more detail than the minimum required for inclusion in their tariff, while others have not. In this report, we do our best to assess how closely each benefit metric aligns with Order 1920 requirements using available information.

The current state of all benefit metric development for long-term planning:

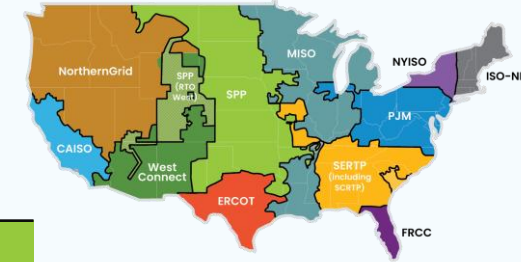
- **CAISO**: Revised tariff filed with FERC in Dec. 2025. No public work on defining benefits aside from what is included in tariff revisions.
- **NorthernGrid**: Targeting June 2026 filing date for revised tariff. No public work on defining benefits aside from tariff revisions.
- **WestConnect**: Targeting June 2026 filing date for revised tariff. No public work on defining benefits aside from tariff revisions.
- **SPP**: Targeting June 2026 filing date for revised tariff. Hired consultant to advise on benefit revisions needed and currently engaging stakeholders on choosing preferred benefit methodologies. SPP Board approved tariff revisions in May 2026.
- **MISO**: Targeting June 2026 filing date for revised tariff. Internal analysis of potential metric methodologies and stakeholder engagement.
- **FRCC**: Targeting June 2026 filing date for revised tariff. No public work on defining benefits aside from tariff revisions.
- **SERTP**: Targeting Dec. 2026 filing date for revised tariff. Internal analysis of potential metric methodologies and stakeholder engagement.
- **PJM**: Revised tariff filed in Dec. 2025. Internal analysis of potential metric methodologies and stakeholder engagement.
- **NYISO**: Targeting June 2026 filing date for revised tariff. No public work on defining benefits aside from tariff revisions.
- **ISO-NE**: Targeting June 2027 filing date for revised tariff. No public work on defining benefits aside from tariff revisions.



Even though many regional planners consider multiple metrics in benefits evaluation, they are not all aligned with Order 1920.

Existing benefits evaluation: ● Benefit present & aligned ◐ Benefit present but not fully aligned ○ Benefit absent

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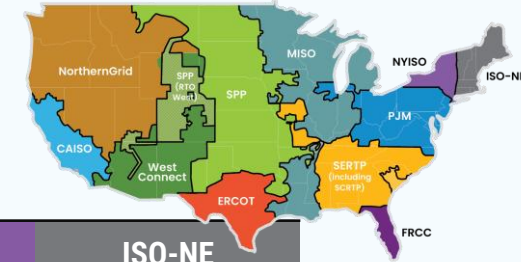
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|-----------------|---|---------|------|--------------|------|-------------|------|---------|------|---------|------|
| No. | Benefit | Current | Plan | Current | Plan | Current | Plan | Current | Plan | Current | Plan |
| 1 | Avoided or deferred reliability facilities and aging infrastructure replacement | ● | ■ | ● | □ | ◐ | □ | ○ | N/A | ◐ | ■ |
| 2 | Reduced costs related to resource adequacy | ◐ | □ | ○ | ■ | ◐ | □ | ○ | N/A | ○ | ■ |
| 3 | Production cost savings | ● | ■ | ◐ | ■ | ● | ◻ | ● | N/A | ● | ■ |
| 4 | Reduced transmission energy losses | ● | ■ | ◐ | ■ | ○ | ◻ | ◐ | N/A | ● | ■ |
| 5 | Reduced congestion due to transmission outages | ◐ | ■ | ○ | ■ | ○ | ◻ | ◐ | N/A | ● | ■ |
| 6 | Mitigation of extreme weather events and unexpected system conditions | ○ | □ | ○ | □ | ○ | ◻ | ○ | N/A | ○ | ■ |
| 7 | Capacity cost benefits from reduced peak energy losses | ● | ■ | ○ | □ | ○ | □ | ○ | N/A | ● | ■ |

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|-----------------|---|---------|------|---------|------|-------------|------|---------|------|---------|------|---------|------|
| No. | Benefit | Current | Plan | Current | Plan | Current | Plan | Current | Plan | Current | Plan | Current | Plan |
| 1 | Avoided or deferred reliability facilities and aging infrastructure replacement | ● | ■ | ● | □ | ● | ◑ | ○ | □ | ◐ | □ | ● | □ |
| 2 | Reduced costs related to resource adequacy | ● | ■ | ○ | □ | ○ | ■ | ● | □ | ● | □ | ● | □ |
| 3 | Production cost savings | ● | ■ | ○ | □ | ○ | ◑ | ● | ■ | ● | □ | ● | □ |
| 4 | Reduced transmission energy losses | ● | ■ | ● | □ | ● | ■ | ○ | ■ | ○ | □ | ● | □ |
| 5 | Reduced congestion due to transmission outages | ● | ■ | ○ | □ | ○ | ■ | ○ | ■ | ○ | □ | ○ | □ |
| 6 | Mitigation of extreme weather events and unexpected system conditions | ◐ | □ | ○ | □ | ○ | ■ | ○ | □ | ◐ | □ | ○ | □ |
| 7 | Capacity cost benefits from reduced peak energy losses | ● | ■ | ○ | □ | ○ | ■ | ○ | □ | ○ | □ | ○ | □ |

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Benefit spread from recent multi-value portfolios

MISO, SPP, and NYISO currently consider a range of benefits when evaluating high-capacity transmission portfolios. While the ISOs do not currently consider all Order 1920 benefits, a look at recent portfolios demonstrates how transmission value can be distributed among a wider suite of benefits.

Both benefit definition and portfolio specifics impact how benefits are distributed.

Portfolio benefits are more evenly spread in MISO and NYISO's recent portfolios than in SPP, where value is concentrated in production cost savings given the vastly increased access to lower cost generation provided by SPP's 2024 portfolio.

Demonstration of multivalue benefit spread from recent regional transmission portfolios.

Benefit values are shown relative to total portfolio cost (unitless). If the sum of all individual benefits results in a total benefit of at least 1.0, then the portfolio benefits are greater than costs.

All RTOs use different financial parameters when calculating benefits, so they should not be compared to one another: MISO's 2024 Tranche 2.1 LRTP (40-yr NPV & 7.1% discount rate), SPP's 2024 ITP (40-yr NPV & 8.0% discount rate), and NYISO's 2019 AC PPTP (45-yr NPV & 7.0% discount rate). The high value is shown below when multiple sensitivities were provided in the evaluation.



Total Portfolio Benefit-to-Cost Ratios

3.7 MISO 2024 Tranche 2.1 Long-Range Transmission Plan (LRTP)

10.4 SPP 2024 Integrated Transmission Plan (ITP)

1.5 NYISO 2019 AC Public Policy Transmission Plan (PPTP)

Important Considerations for Benefit Quantification

Order 1920 requires regional planners to model three future scenarios out 20 years.

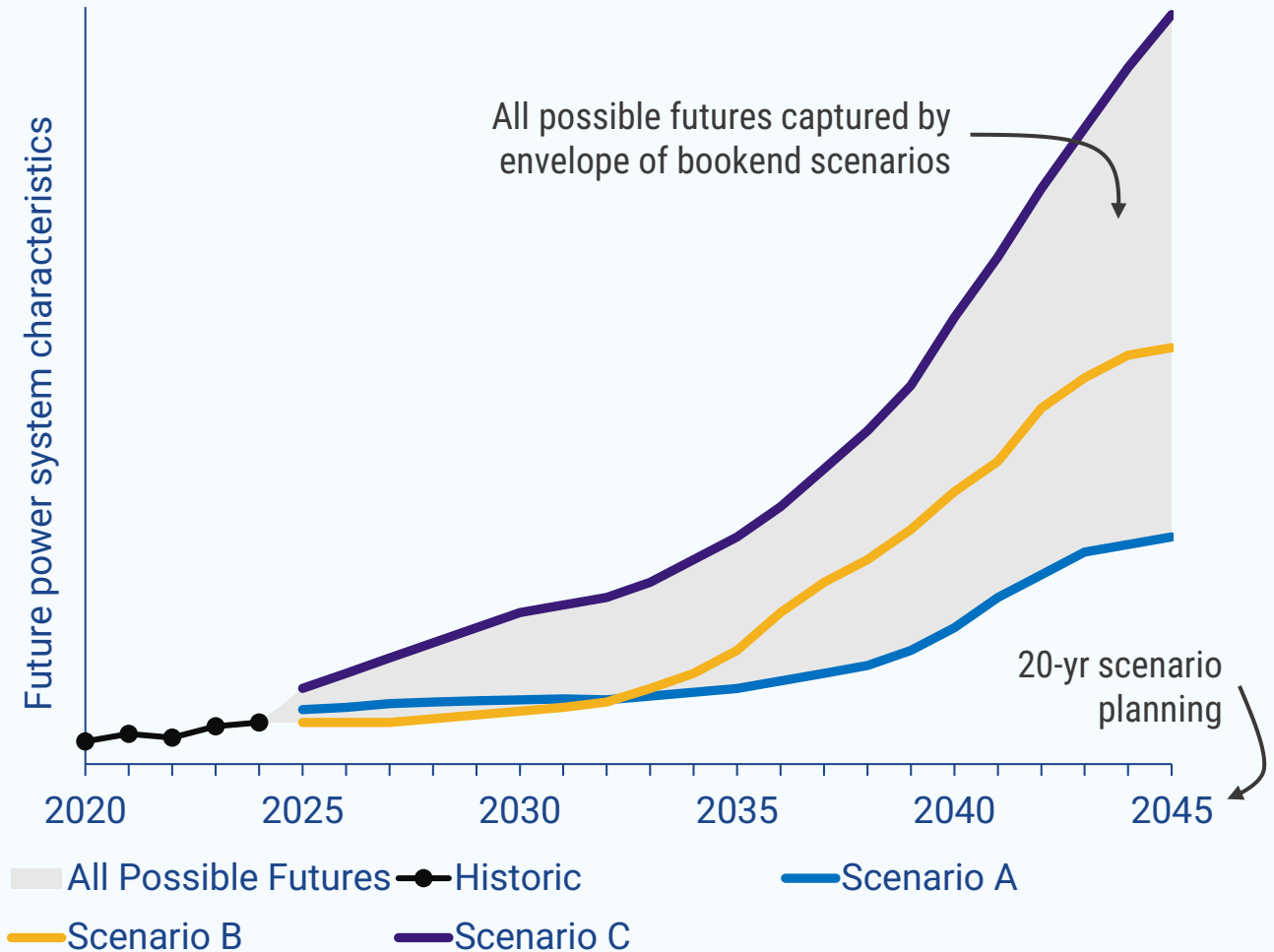
No individual forecast of the future will be correct.

- Scenario-based planning will enable transmission solutions which work best across a range of plausible futures.
- Scenarios should enclose anticipated futures given choice of bookend scenarios.

Characteristics of future power system to include in scenarios:

- Demand growth
- Generation additions and retirements
- Fuel costs
- Public policies, laws, and regulations
- Forecasted weather changes

Capacity expansion modeling is best equipped to capture the above characteristics when developing plausible and diverse scenarios.



Regional planners must estimate benefits of a candidate solution into the future.

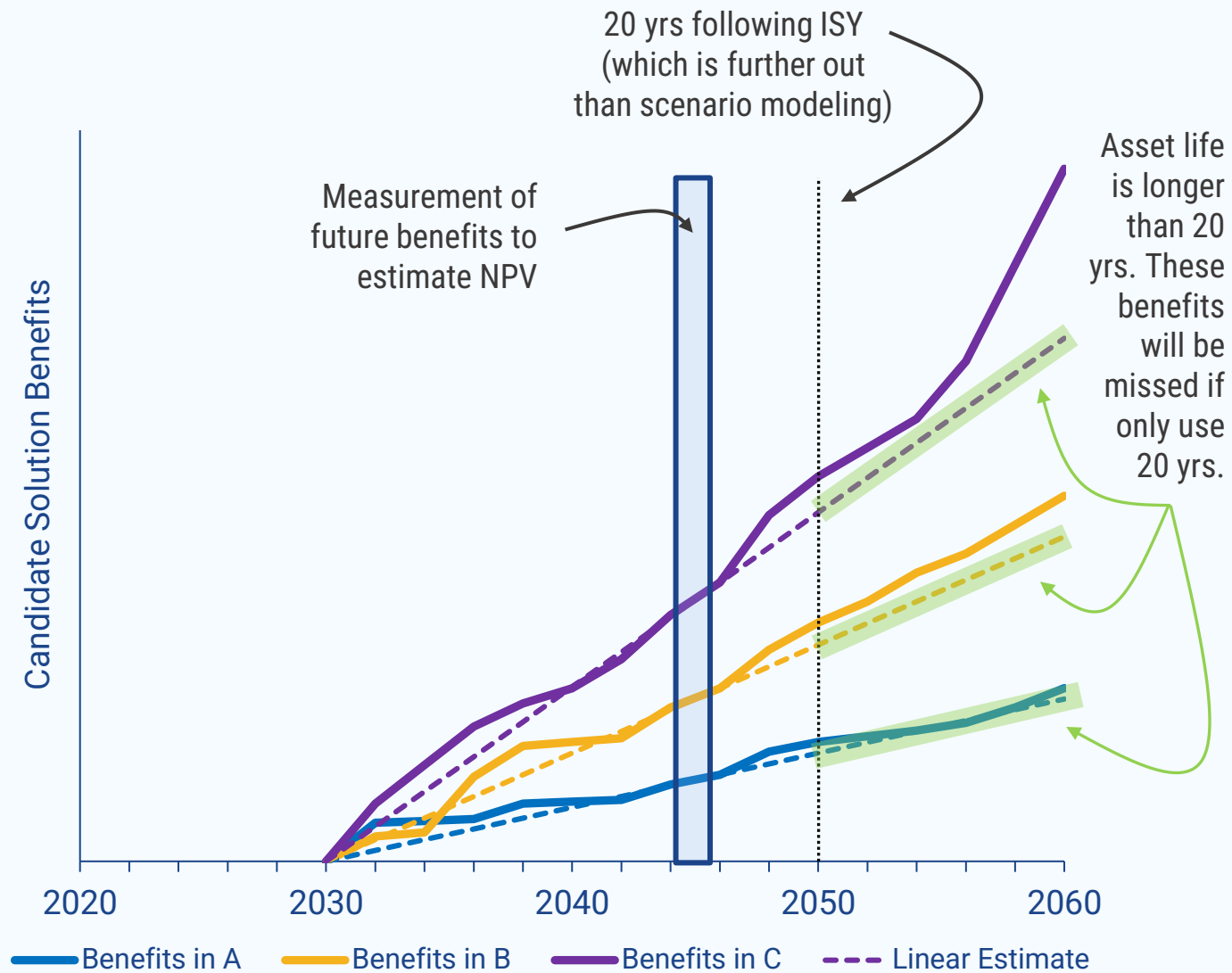
Regional planners must calculate benefits across all scenarios in at least one future year to estimate net present value (NPV) of the candidate solution over many years.

- Use linear inter/extrapolation to estimate benefits in other years (dotted lines)

Order 1920 requires calculation of the value of candidate solutions at least 20 years following facility in-service year (ISY). (P 225)

- Most regional planners currently count the 20 years starting from when planning begins and not the ISY.

Best practice is to calculate the NPV of a candidate solution for the length of its depreciation life, 40+ years in the case of transmission.



When benefits are measured matters for alternative solutions.

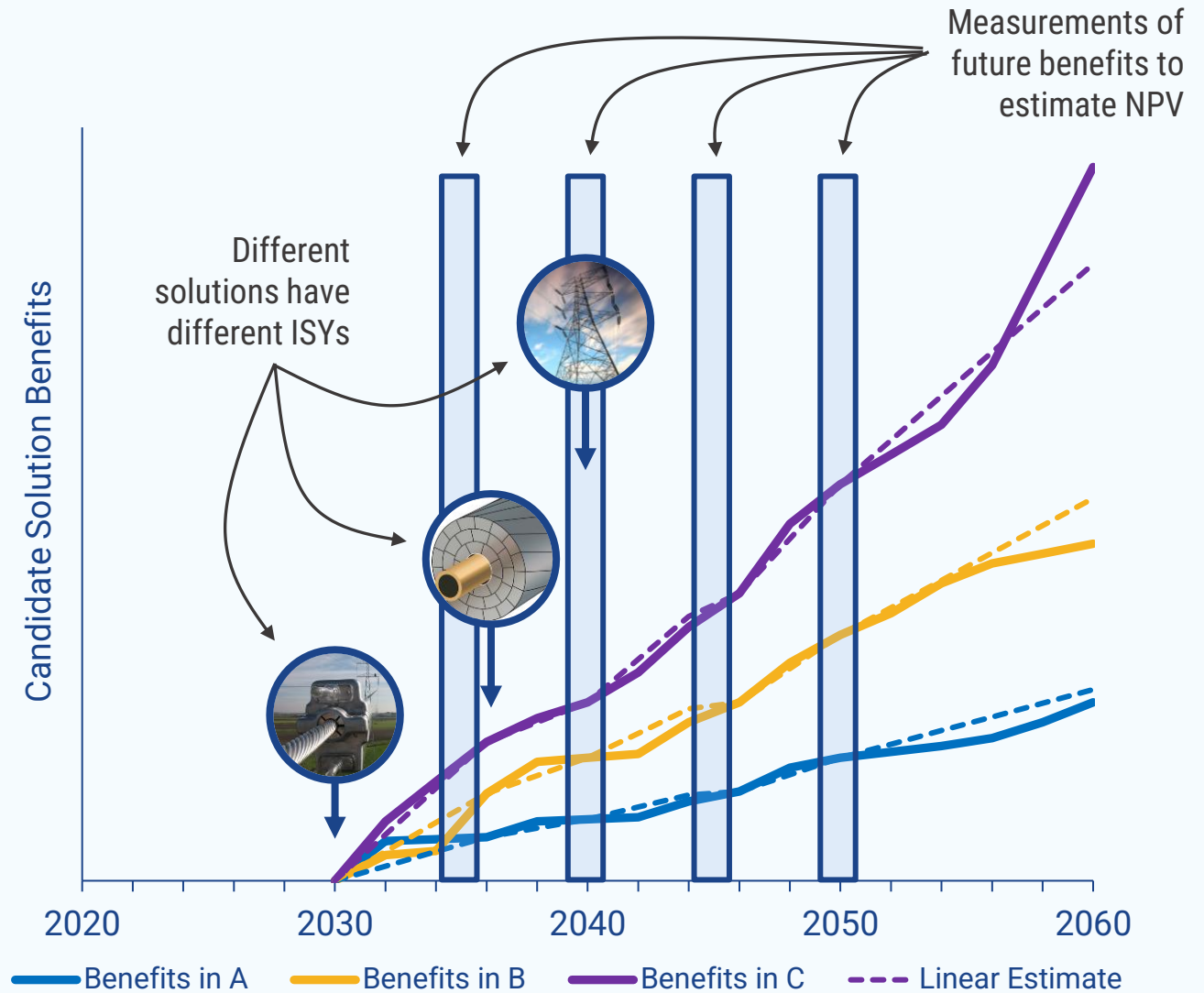
Benefits of transmission will not accrue linearly.

- Changes in system demand, generation, policy, weather, and topology will all impact annual benefit evaluation.

Linearizing annual benefits from only a single measurement is computationally efficient but inherently inaccurate.

- Transmission solutions – including advanced transmission technologies – can be implemented on different timeframes.
- Cumulative benefits of sooner-to-deploy solutions could be missed if regional planners use a single year for evaluation.

Best practice is to measure benefits every five years and inter/extrapolate for other years.



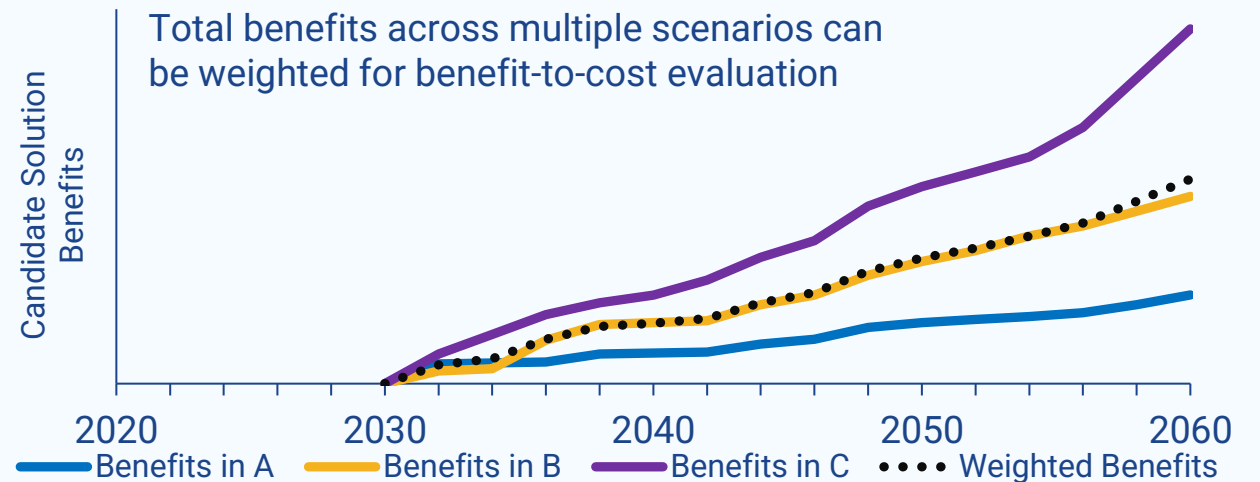
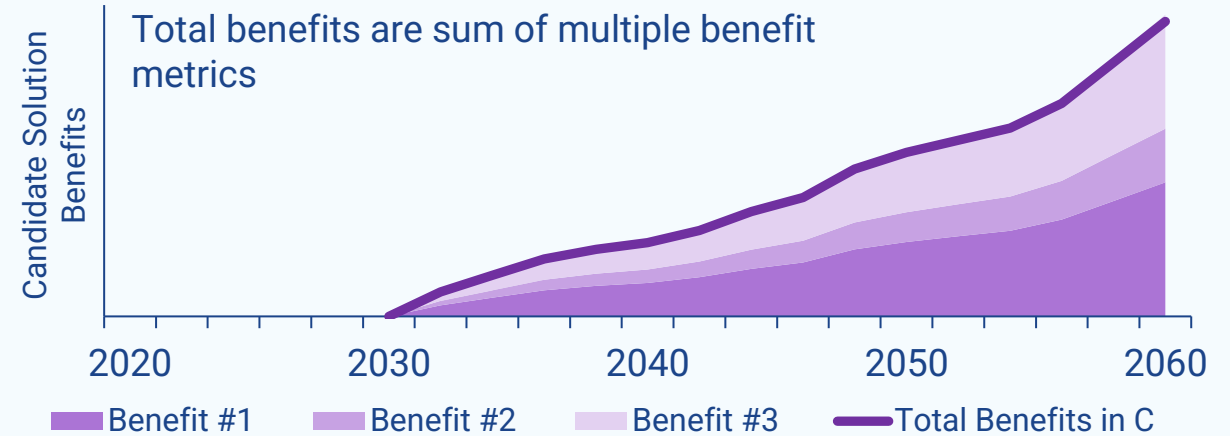
Benefits of candidate solutions should be measured for all scenarios.

The benefits produced in every scenario should be used in candidate transmission evaluation.

- Transmission benefits can be weighted differently for each scenario if emphasis on one scenario over another is desired.

Example benefits evaluation for candidate solution that costs \$30B. Scenarios are weighted as 25%/50%/25%

| Billions of USD | Scen. A | Scen. B | Scen. C |
|---------------------------------|----------------|---------|---------|
| Benefit #1 | \$10 | \$20 | \$25 |
| Benefit #2 | \$15 | \$15 | \$10 |
| Benefit #3 | \$15 | \$5 | \$20 |
| Sum of Multiple Benefits | \$40 | \$40 | \$55 |
| Weighted Average | \$43.75 | | |
| B/C Ratio | 1.45 | | |



Choice of base case characteristics impacts final benefits evaluation.

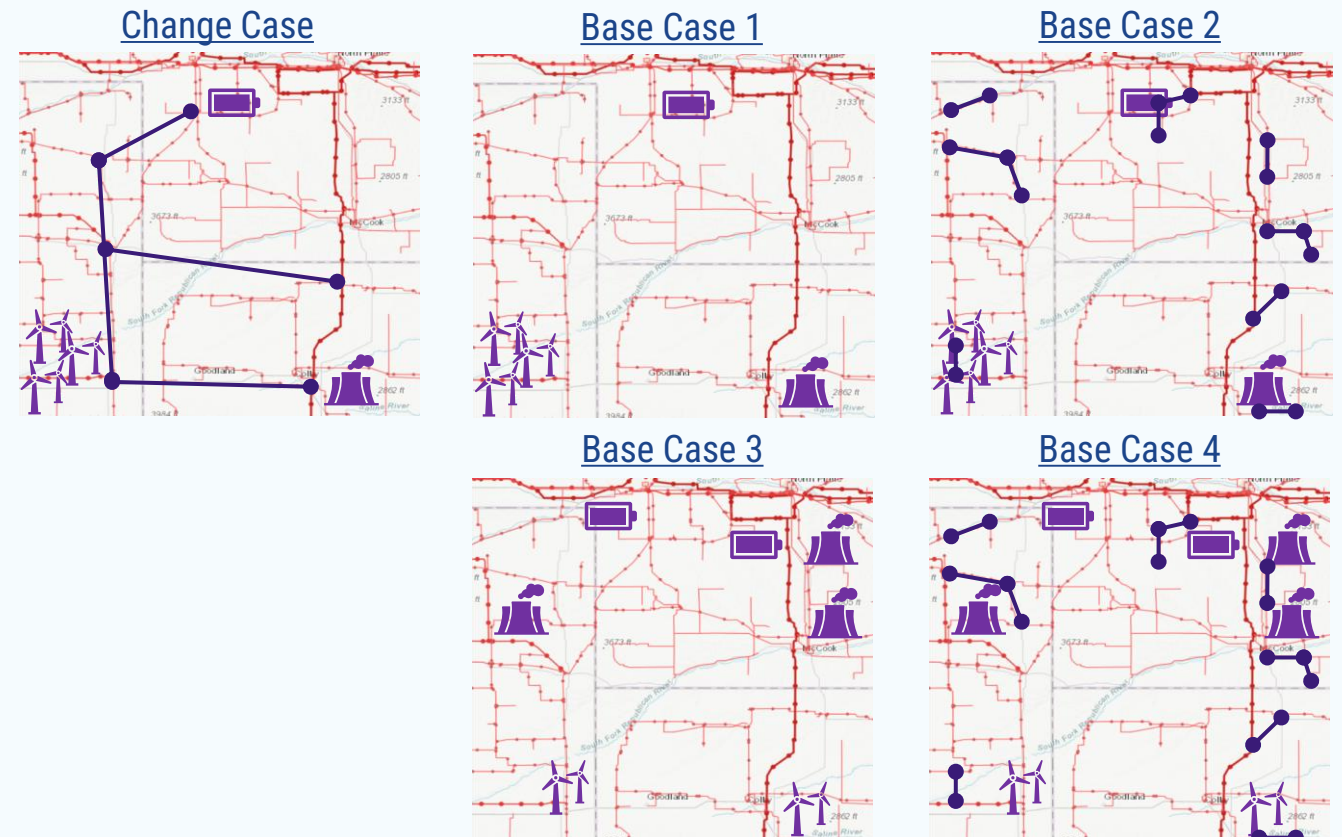
Benefits are measured as the difference in benefits evaluated between the *change* case (future system with regional facilities) and *base case* (future system without regional facilities).

The choice of future generation and transmission buildouts in the base case will impact the value of individual benefit metrics.

- For example, adding local generation instead of regional generation to the base case may reduce loss of load while increasing generation production and capacity costs.
- While the measure of individual benefit metrics will differ depending on the choice of base case, the total overall measure of benefits should be directionally consistent.

Like all considerations, agreement on base case characteristics before evaluation begins is important.

| Case | Generation Profile | Transmission Profile |
|----------------------|-----------------------------|-----------------------------|
| Change Case | Regional capacity expansion | Regional capacity expansion |
| Base Option 1 | Regional capacity expansion | Current system |
| Base Option 2 | Regional capacity expansion | Local capacity expansion |
| Base Option 3 | Local capacity expansion | Current system |
| Base Option 4 | Local capacity expansion | Local capacity expansion |



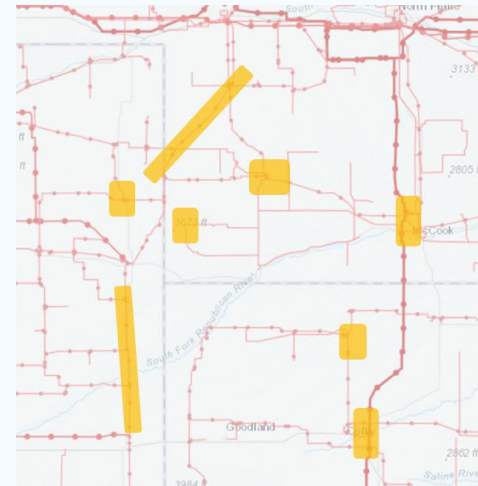
Portfolio-based benefit evaluation will result in the most efficient project selection.

While not required by Order 1920, best practice suggests that evaluating the benefit-to-cost ratio (B/C) of a portfolio of facilities – rather than each one individually – is likely to result in the most efficient solutions.

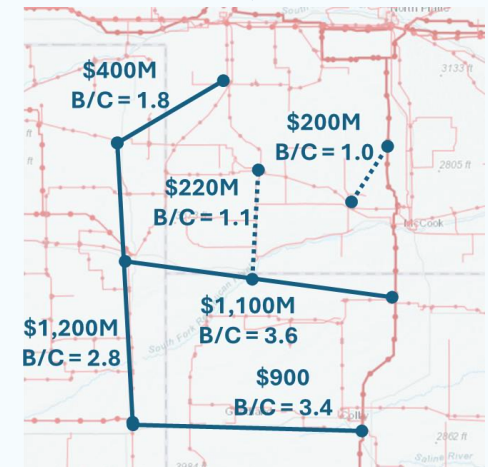
To illustrate the risk of higher costs under an individual facility B/C test, consider a system with eight needs.

- Portfolio A has six facilities with individual B/C ranging from 1.0 to 3.6 and a portfolio B/C of 3.0.
- Two facilities have individual B/C less than the planner-imposed threshold of 1.25. Declining to build these two facilities would lead to unmet system needs.
- Portfolio B aims to address those needs by adding a more expensive facility with a higher individual B/C. The resulting portfolio addresses all needs but at a higher cost (\$4.2B) and lower portfolio B/C (2.8).
- While both portfolios offer high benefits, the original portfolio A would have resolved all needs more efficiently, *saving ratepayers money*.

Original System
8 distinct needs

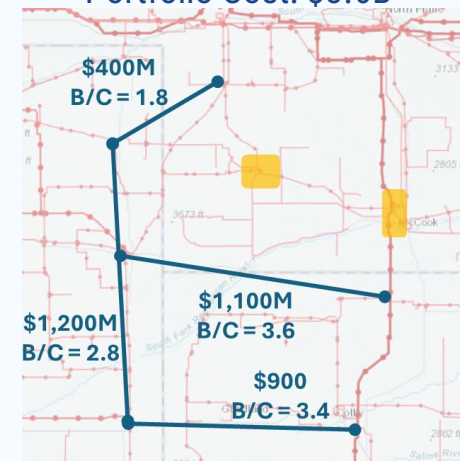


Portfolio A
6 solutions; All 8 needs addressed
Portfolio Cost: \$4.0B; Portfolio B/C = 3.0



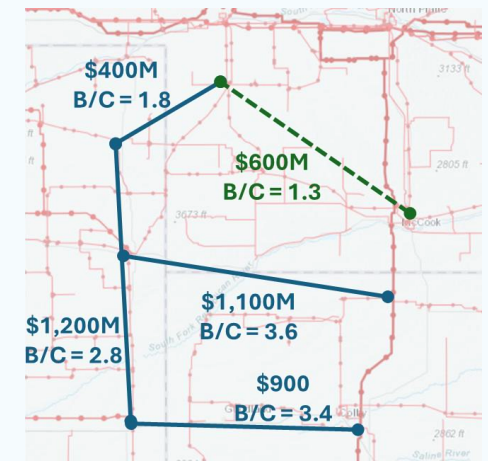
Partial A

4 solutions; 6 of 8 needs addressed
Portfolio Cost: \$3.6B



Portfolio B

4 solutions + 1 new; All 8 needs addressed
Portfolio Cost: \$4.2B; Portfolio B/C = 2.8



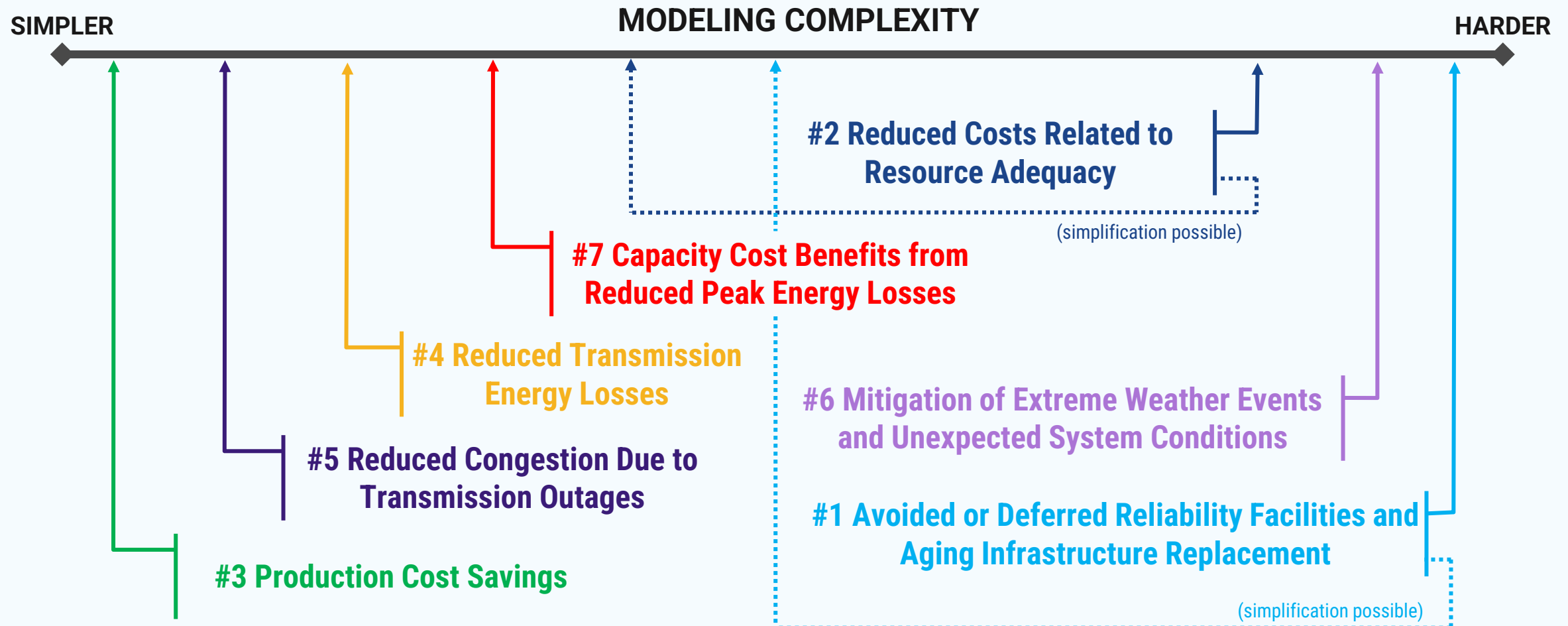
Order 1920 Benefit Metrics

The required Order 1920 benefits and potential evaluation methodologies

| ORDER 1920 BENEFIT | DESCRIPTION | METHOD (DELTA of TWO SCENARIOS) | MONETIZATION (NPV) |
|--|---|--|--|
| 1 Avoided or deferred reliability transmission facilities and aging infrastructure replacement | Reduced costs achieved by delaying or avoiding transmission facility additions / upgrades to address near-term reliability needs and replace aging infrastructure. | Identify planned transmission facilities—as determined by local utilities—that are deferred or avoided from the candidate facility AND Difference in future thermal overloads between base and change cases | Transmission capex [\$] of avoided facility additions / upgrades- AND Proxy costs for transmission facilities to overcome thermal overloads |
| 2 Reduced Costs Related to Resource Adequacy | Enhanced power system reliability from either a) reducing unserved energy, OR b) reducing generation needed to maintain loss of load expectation. | a) Difference in unserved load between base and change cases OR b) Difference in generation capacity needed to meet PRM requirements between base and change cases | a) Avoided unserved load [MWh] x value of lost load [\$/MWh] OR b) Avoided cost of new entry [\$/kW-yr] x generation [MW] |
| 3 Production cost savings | Reduced cost of generating electricity by using less expensive power—now accessible by larger transmission network—to meet demand. | Difference in production costs between base and change cases (ignoring transmission losses) under typical conditions | Avoided production costs [\$] |
| 4 Reduced transmission energy losses | Reduced energy losses across transmission facilities when moving power from supply sources to load centers. | Difference in production costs between base and change cases (for only transmission losses) under typical conditions OR Difference in transmission losses between base and change cases, calculated using known electrical parameters and expected power flow | Avoided production costs [\$] OR Avoided losses [MWh] x shadow node price [\$/MWh] |
| 5 Reduced congestion due to transmission outages | Reduced cost of generating electricity resulting from avoided congestion during transmission outages. Increased transmission capacity reduces overall congestion on the system. | Difference in production costs between base and change cases (including transmission losses) under contingency conditions | Avoided production costs [\$] |
| 6 Mitigation of extreme weather events and unexpected system conditions | Reduced cost of generating electricity and loss of load during extreme weather events and unexpected system conditions, including the value of interregional transfer capability. | Difference in production costs between base and change cases (including transmission losses) under stress conditions AND Difference in unserved load between base and change cases under stress conditions | Avoided production costs [\$] AND Avoided unserved load [MWh] x value of lost load [\$/MWh] |
| 7 Capacity cost benefits from reduced peak energy losses | Reduced generation capacity investments needed given reduced transmission losses to serve peak demand. | Difference in generation capacity needed to makeup system transmission losses during peak demand hour between the base and change cases | Avoided cost of new entry [\$/kW-yr] x peak hour losses [MW] |

Some benefits are harder to calculate than others, but tricks can be applied to simplify the modeling.

Subsequent slides define each benefit in order of complexity rather than FERC's numeric order.



What is in a name?

How to translate FERC lingo to modeling choices.

This framework will be repeated to help define each Order 1920 benefit metric.

What is being measured?

Generation Production

Generation Capacity

Unserved Energy

Transmission Capacity

What are weather and load conditions during measurement?

Typical

Stress

Are all resources available during measurement?

Generation Outages

Transmission Outages

Used to define modeling cases (next slide)

When is measurement taken?

All hours of year

Peak demand hour(s)

Critical stress hours

How to monetize the benefit?

Production Cost [\$]

CONE [\$/kW-yr]

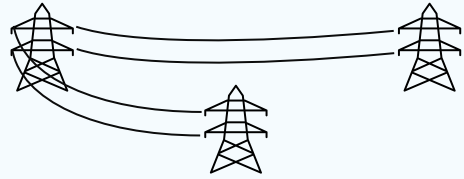
VOLL [\$/MWh]

Tx Cost [\$/kV-mi]

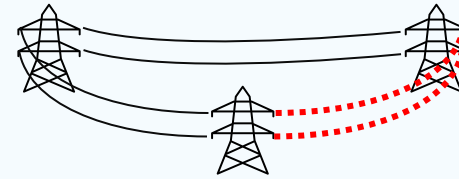
Marg. Cost [\$/MWh]

Modeling cases needed to evaluate benefits of candidate transmission solutions for each future scenario.

This framework will be repeated to help define each Order 1920 benefit metric.



Base Case



Change Case

| | | | |
|--------------|----------------------|--------------|----------------------|
| TC_0 | Typical Conditions | SC_0 | Stress Conditions |
| TC_0^{N-x} | Transmission Outages | SC_0^{N-x} | Transmission Outages |
| TC_0^{RA} | Generator Outages | SC_0^{RA} | Generator Outages |

| | | | |
|--------------|----------------------|--------------|----------------------|
| TC_1 | Typical Conditions | SC_1 | Stress Conditions |
| TC_1^{N-x} | Transmission Outages | SC_1^{N-x} | Transmission Outages |
| TC_1^{RA} | Generator Outages | SC_1^{RA} | Generator Outages |

Repeat for each candidate

Subsequent slides describe benefit metrics one-by-one

- Descriptions of each benefit metric are organized as follows:
 - i. A suggested benefit evaluation methodology
 - ii. Examples of different methodologies used by regional planners
 - iii. The implications of different metric methodological choices
- Regional planners' example methodologies include both *existing* practices from Order 1000 near-term system planning Business Practice Manuals and *proposed* practices to meet Order 1920 long-term system planning requirements.
 - The benefit metrics used in existing practices are not ubiquitous across any individual planner's processes. For example, a planner may use production cost metrics to evaluate economic projects but not reliability projects.
 - The descriptions given in these tables are a simplification. More details are available in the source documents.
- Order 1920 benefit evaluation methodologies are still being developed by each regional planner, with some further along in their development than others. Each regional planner's proposed benefit evaluation method is analyzed here to best of our ability using information available at the time of publication. These benefit metrics are likely to change with time.
- Cost allocation is not discussed in this report, except in instances where a benefit-to-cost (B/C) ratio of one – which assumes a solution's benefits are equal to its costs – is explicitly assumed by the benefit methodology and an explanation of cost allocation helps illustrate the methodology.

Order 1920 Benefit #3 - Production cost savings

Description

Reduced cost of generating electricity by using less expensive power—now accessible by larger transmission network—to meet demand.

Potential Method

Difference in production costs between base and change cases (ignoring transmission losses) under typical conditions.

Measurement

Generation Production

Generation Capacity

Unserved Energy

Transmission Capacity

Grid Conditions

Typical

Stress

Resource Availability

Transmission Outages

Generation Outages

Sampling Fidelity

All hours in year

Peak demand hour(s)

Critical stress hours

Monetization

Production Cost [\$]

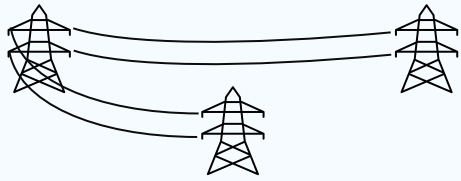
CONE [\$/kW-yr]

VOLL [\$/MWh]

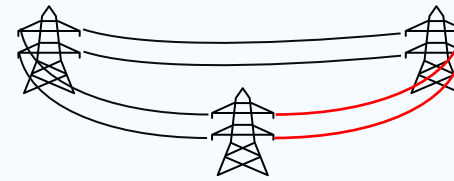
Tx Cost [\$/kV-mi]

MC [\$/MWh]

Avoided production cost = Production costs of TC_0 – Production costs of TC_1



Base Case



Change Case

| | | | |
|--------------|-----------------------------|--------------|-----------------------------|
| TC_0 | Typical Conditions | SC_0 | Stress Conditions |
| TC_0^{N-x} | Transmission Outage Profile | SC_0^{N-x} | Transmission Outage Profile |
| TC_0^{RA} | Generator Outage Profile | SC_0^{RA} | Generator Outage Profile |

| | | | |
|--------------|-----------------------------|--------------|-----------------------------|
| TC_1 | Typical Conditions | SC_1 | Stress Conditions |
| TC_1^{N-x} | Transmission Outage Profile | SC_1^{N-x} | Transmission Outage Profile |
| TC_1^{RA} | Generator Outage Profile | SC_1^{RA} | Generator Outage Profile |

Examples from regional planners: Adjusted production costs

| Region | Benefit | Description | Method | Monetization |
|--------------|---|---|--|---|
| MISO | Congestion and fuel savings | Measures the reduction in congestion costs and generator production costs. Transmission allows for more efficient access to low-cost resources and reduces congestion costs with a more economical dispatch of resources. | Difference in APC between base and change cases, calculated using nodal PCM under N-1 conditions. Imports and exports are included. | Zonal APC (\$) |
| SPP | Adjusted production cost savings | Reduced production costs, including fuel and other variable operating costs of power generation, realized when new transmission allows for increased dispatch of lower-cost resources. | Difference in APC between base and change cases, calculated using nodal PCM under N-1 conditions. Exports are valued at the weighted average generation LMP of the exporting zone. | Zonal (company-level) and footprint-wide APC (\$) |
| ISO-NE | Production cost and congestion savings | These savings will be quantified as the difference between versions of the production cost model with and without the transmission project. | Difference in APC between base and change cases, calculated using nodal PCM under N-1 conditions | Footprint-wide APC (\$) |
| NYISO | Production cost savings | The principal metric for measuring the economic benefits of each generic solution is the NYCA-wide production cost savings that would result from each generic solution, expressed as the present value over the 20-year planning horizon. | Difference between footprint-wide APC between base and change cases, calculated using nodal PCM under N-1 conditions. | Footprint-wide APC (\$) |
| West Connect | <i>Proposal:</i> Production cost savings | Savings in fuel and other generation operating costs that are realized from increased dispatch of lower production-cost generation over higher production cost generation and, where applicable, reduced market clearing prices as lower-cost generation suppliers increasingly set market-clearing prices. | Difference in APC on enrolled TP's transmission facilities between base and change cases under N-0 conditions. | Company-level APC (\$) |
| SERTP | <i>Proposal:</i> Production cost savings | Fuel and variable operations and maintenance cost savings associated with facility that enhances the ability to dispatch generation units more economically. | Measure change in APC between enrolled TPs between base and change cases under N-0 conditions. Currently debating whether to use nodal or zonal PCM with addition of hurdle rates. | Company-level APC (\$) |

Examples from regional planners: Load and generator payments

| Region | Benefit | Description | Method | Monetization |
|---------------|---|--|--|--|
| CAISO | Production cost benefits | Benefits resulting from changes in the net ratepayer payment based on production cost simulation as a consequence of the proposed transmission upgrade. | Difference in net load payments between the base and change cases, calculated using nodal PCM under N-1, N-1-1, and N-2 conditions. | Load energy payments: LMP (\$/MWh) x energy consumption (MWh) |
| PJM | Energy market benefit | Annual economic impact of the enhancement for each of the future study years. | Difference in APC savings between the base and change cases, calculated using nodal PCM given N-1 conditions. Half of value from difference in footprint-wide energy production cost and half from difference in load energy payments, where load energy payment is expected zonal wholesale payments. | Weighted sum of <ul style="list-style-type: none"> Footprint-wide APC (\$) Load energy payments: LMP (\$/MWh) x energy consumption (MWh) |
| ERCOT | <ul style="list-style-type: none"> Production cost Consumer energy cost | Consideration of – though not the sum of – three different production cost saving related benefits. Project may be recommended if passes either economic eligibility test. | Difference in... <ul style="list-style-type: none"> Production cost Consumer energy costs ... between base and change cases. All three are calculated using nodal PCM under N-1 conditions. | Independently considers <ul style="list-style-type: none"> Footprint-wide APC (\$) Load energy payments: LMP (\$/MWh) x energy consumption (MWh) |
| Northern Grid | Increased useful available transfer capability (combined O1920 Benefits #3 & #4) | The increased annual revenue from sales at cost-based rates projected to be accrued by TP over the life of the regional facility due to an increase in transmission capacity and reduction of losses on TP's system. | Difference in annual sales to the TP between base and change cases. Use nodal PCM under N-0, N-1, and any additionally requested contingency conditions. | TP revenues (\$) |

Summary and implications of different benefit evaluation methodologies

Contingencies must be considered in at least one benefit metric

- Order 1920 requires production cost savings under transmission outages (contingencies) be captured in Benefit #5 and not #3 [P769]. However, including N-1 contingencies in production cost modeling is necessary to calculate locational marginal prices (LMP). Regional planners which use LMPs will likely continue to include N-1 contingencies in Benefit #3.
- The total benefits of a candidate project will be equivalent so long as N-1 contingencies are captured in either Benefit #3 or #5, with higher order contingencies additionally captured also in #5.
- **WestConnect** and **SERTP's** proposal omit all contingencies (N-0) in their benefit evaluations while **CAISO** currently includes all NERC TPL contingencies (N-1, N-1-1, and N-2). **All other regional planners** are somewhere in between, with most considering single N-1 contingencies.

Nodal production cost modeling is best practice

- PCM best practice requires nodal modeling as it inherently captures the value of reduced transmission congestion and economic dispatch. The nodal results should then be aggregated up to zonal- or footprint-wide savings for benefit evaluation and cost allocation.
- Most regional planners use nodal PCM. The exception would be **FRCC** (not listed, see accompanying spreadsheet) and **SERTP's** potential proposals to use zonal PCM, which will not fully capture this value.
- **SPP** and **WestConnect** aggregate nodal PCM results to company-level APC savings; **MISO** aggregates nodal results to zonal APC savings; and all others currently or plan to aggregate nodal results to footprint-wide APC savings.

Focus on ratepayer savings is possible

- Minimizing system-wide adjusted production savings (APC) is equivalent to maximizing social welfare, which treats producers and consumers equally. Some benefit evaluation practices—such as emphasis on minimizing load payments—put more focus on lowering consumer costs.
- **PJM**, **CAISO**, and **ERCOT** include nodal load payments in their existing benefit calculations, either in addition to or instead of system APC savings.
- Conversely, **NorthernGrid** bases their existing benefit on increased generation sales, putting greater emphasis on increasing transmission provider revenues. Their proposed Order 1920 Tariff revisions change this practice to focus on APC savings instead of increasing generation sales.

Order 1920 Benefit #5 - Reduced congestion due to transmission outages

Description

Reduced cost of generating electricity resulting from avoided congestion during transmission outages. Increased transmission capacity reduces overall congestion on the system.

Potential Method

Difference in production costs between base and change cases (including transmission losses) under contingency conditions

Measurement

Generation Production

Generation Capacity

Unserved Energy

Transmission Capacity

Grid Conditions

Typical

Stress

Resource Availability

Transmission Outages

Generation Outages

Sampling Fidelity

All hours in year

Peak demand hour(s)

Critical stress hours

Monetization

Production Cost [\$]

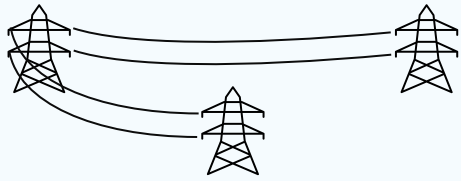
CONE [\$/kW-yr]

VOLL [\$/MWh]

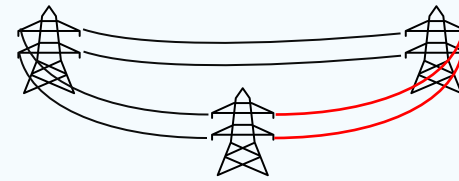
Tx Cost [\$/kV-mi]

MC [\$/MWh]

Avoided production cost under contingency conditions =

$$[\text{Production costs of } TC_0^{N-x} - \text{Production costs of } TC_1^{N-x}]$$


Base Case



Change Case

| | | | | | | | |
|--------------|-----------------------------|--------------|-----------------------------|--------------|-----------------------------|--------------|-----------------------------|
| TC_0 | Typical Conditions | SC_0 | Stress Conditions | TC_1 | Typical Conditions | SC_1 | Stress Conditions |
| TC_0^{N-x} | Transmission Outage Profile | SC_0^{N-x} | Transmission Outage Profile | TC_1^{N-x} | Transmission Outage Profile | SC_1^{N-x} | Transmission Outage Profile |
| TC_0^{RA} | Generator Outage Profile | SC_0^{RA} | Generator Outage Profile | TC_1^{RA} | Generator Outage Profile | SC_1^{RA} | Generator Outage Profile |

Examples from planners

| Region | Benefit | Description | Method | Monetization |
|--------------|--|--|--|-------------------------|
| MISO | Reduced transmission outage costs | Transmission outages reduce operational transmission capacity and can impact congestion. Captures incremental savings that more fully reflect the effects of congestion under actual operating conditions. | Difference in APC between base and change cases given increased outages. Outage cases reflect historical operational outages experienced between 2014-2019. Difference between these is reduced by APC savings in Benefit #3 to avoid double counting. Uses nodal PCM. | Zonal APC (\$) |
| SPP | Mitigation of transmission outage costs | Incremental reduction to adjusted production cost savings when forced and planned outages are simulated. | Apply APC differences calculated in old Regional Cost Allocation Review (RCAR II) study results to the base and change APC calculations under normal conditions from Benefit #3. | Company-level APC (\$) |
| PJM | <i>Proposal:</i> Reduced congestion due to transmission outages | Production cost impacts from transmission outages with and without the facility/plan/portfolio. | Difference in APC between base and change case due to standard TPL transmission outage profiles. Intend to perform this analysis at the same time as the PCM run for Benefit #3, with proper accounting of APC changes given outages. | Footprint-wide APC (\$) |
| West Connect | <i>Proposal:</i> Reduced congestion due to transmission outages | Reduction in production costs from avoided congestion resulting from a single contingency transmission outage as a result of a proposed facility. | Difference in APC on enrolled TP's transmission facilities between base and change cases under N-1 conditions. | Company-level APC (\$) |
| SERTP | <i>Proposal:</i> Reduced congestion due to transmission outages | Fuel and variable operations and maintenance cost savings associated with facilities that reduce the extra cost incurred during periods of transmission outages that constrain economic dispatch. | Difference in APC between enrolled TPs between base and change cases given transmission outages. Careful to only measure hours of expected transmission outages. Outage conditions will be chosen at the beginning of each planning cycle. | Company-level APC (\$) |

Summary and implications of different benefit evaluation methodologies

Transmission outages above standard N-1 contingencies should be evaluated here

- This metric is intended to show reduced congestion benefit during transmission outages, including contingencies above and beyond the N-1 contingencies used in LMP calculation (discussed previously).
- NERC has developed a standard list of contingencies which all planners consider when evaluating system needs. Those same contingencies could be evaluated here. Better would be to include additional transmission outages which are known to cause congestion and stress the system.
- **PJM, WestConnect, and CAISO** propose to use the standard NERC transmission planning contingencies to calculate this benefit.
- **MISO** and **SPP** use historic outage profiles to calculate this benefit instead of standard planning contingencies.
 - Historic outage profiles should be updated to reflect recent operational experience and system topology.
- **SERTP** intends to choose relevant outage conditions at the beginning of each planning cycle.
- **NYISO** considers transfer capability under standard planning contingencies in its solution screening criteria, but not in its benefits evaluation.

Avoid double counting between benefits

- **MISO, SPP, and PJM** have different methods of disaggregating this benefit from the APC savings in Benefit #3 to avoid double counting.

Order 1920 Benefit #4 - Reduced transmission energy losses

Description

Reduced generation needs from decreased losses across transmission facilities when moving power from generation sources to load centers.

Potential Method

Difference in transmission losses between base and change cases, calculated using known electrical parameters and modeled locational prices.

Measurement

Generation Production

Generation Capacity

Unserved Energy

Transmission Capacity

Grid Conditions

Typical

Stress

Resource Availability

Transmission Outages

Generation Outages

Sampling Fidelity

All hours in year

Peak demand hour(s)

Critical stress hours

Monetization

Production Cost [\$]

CONE [\$/kW-yr]

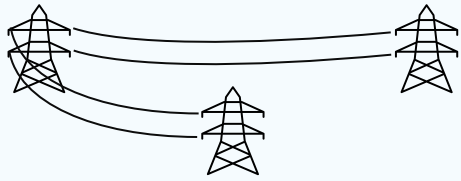
VOLL [\$/MWh]

Tx Cost [\$/kV-mi]

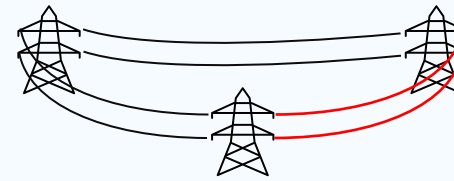
MC [\$/MWh]

Avoided energy losses =

[Transmission losses x Loss shadow price at each node] in TC_0 -
 [Transmission losses x Loss shadow price at each node] in TC_1



Base Case



Change Case

| TC_0 Typical Conditions | | SC_0 Stress Conditions | | TC_1 Typical Conditions | | SC_1 Stress Conditions | |
|---------------------------|-----------------------------|--------------------------|-----------------------------|---------------------------|-----------------------------|--------------------------|-----------------------------|
| TC_0^{N-x} | Transmission Outage Profile | SC_0^{N-x} | Transmission Outage Profile | TC_1^{N-x} | Transmission Outage Profile | SC_1^{N-x} | Transmission Outage Profile |
| TC_0^{RA} | Generator Outage Profile | SC_0^{RA} | Generator Outage Profile | TC_1^{RA} | Generator Outage Profile | SC_1^{RA} | Generator Outage Profile |

Examples from regional planners: Production cost modeling

| Region | Benefit | Description | Method | Monetization |
|--------|--|---|---|-------------------------|
| CAISO | Transmission loss saving benefit | The reduction of transmission losses will save energy and increase the production benefit for the upgrade, which is incorporated into the production cost simulation with full network model. | Difference in APC savings from transmission losses between base and change cases, where losses are modeled as load. Uses nodal PCM. | Footprint-wide APC (\$) |
| MISO | Energy savings from reduced losses | Captures the lower production costs that result from the addition of transmission facilities that reduce overall system losses. | Difference in hourly APC between base and change cases given reduction in transmission system losses, where reduced losses are modeled as a reduction in load. Uses nodal PCM. | Zonal APC (\$) |
| ISO-NE | Reduction in losses | Reduction in transmission system losses provided by the proposed transmission facility. | Difference in hourly APC between base and change cases given reduction in transmission system losses, where reduced losses are modeled as a reduction in load. Uses power flow and nodal PCM. | Footprint-wide APC (\$) |
| PJM | <i>Proposal:</i> Reduced transmission energy losses | More robust transmission reduces losses which can be quantified and valued using the avoided cost of producing that energy. | Difference in hourly APC between base and change cases given reduction in transmission system losses, where reduced losses are modeled as a reduction in load. Will use nodal PCM and calculate reduced transmission energy losses either by scaling load (as done by MISO) or post-processing (as done by ISO-NE). | Footprint-wide APC (\$) |

Examples from regional planners: Transmission loss shadow price and other methods

| Region | Benefit | Description | Method | Monetization |
|---------------|--|---|--|---|
| SPP | Marginal energy losses | Reduction in system losses that occurs when additional transmission capacity reduces total transmission losses. | Hourly calculation of difference in [(LMP Loss Factor) x (Generation)] for the base and change cases, where the LMP loss factor is the LMP loss component (as % of total LMP) at either the load or generator nodes. <ul style="list-style-type: none"> Same calculation also done for imports Calculated for every hour and zone of each studied year | LMP loss component (\$/MWh) |
| SERTP | Real power losses | The cost savings and/or increase associated with real power losses on the transmission system with the implementation of the proposed regional transmission facility estimated for each TP. | Difference in real power system losses for average load between base and change cases using AC power flow model. Losses benefit considered negligible if difference in losses is less than 1MW and if costs exceed benefits for Benefit #1. | Marginal energy production (\$/MWh) |
| SERTP | <i>Proposal:</i> Reduced transmission losses | Fuel and variable operations and maintenance cost savings associated with regional facility that reduces total energy generation needed to meet demand by reducing transmission losses. | Difference in system transmission losses between base and change cases. May use PCM or AC power flow model. | Marginal dispatch cost (\$/MWh) |
| Northern Grid | Increased useful available transfer capability (combined Benefits 3 + 4) | The increased annual revenue from sales at cost-based rates projected to be accrued by TP over the life of the regional facility due to an increase in transmission capacity -and reduction of losses on TP's system. | Difference in annual sales to the TP between base and change cases. Use nodal PCM under N-0 conditions. | TP revenues (\$) |
| FRCC | Total estimated transmission line loss value | The change in transmission losses caused by the regional facility. | Difference in transmission system losses on enrolled TP's systems between the base and change case. Measured during both peak and off-peak conditions. | Method and calculation left to independent consultant to determine. |

Summary and implications of different benefit evaluation methodologies

Calculating reduction in losses explicitly via production cost modeling or a proxy method can be equally valid.

- Including losses in PCM software runs is useful for evaluating multiple production cost savings metrics at once. Unfortunately, this method is computational expensive, so proxy methods to estimate losses can be used instead.
- **CAISO** uses production cost modeling with transmission losses included to evaluate economic facilities, thereby calculating Benefits #3 and #4 simultaneously. The total savings can be separated into two benefits for reporting under Order 1920.
- To avoid computational expense, **MISO** and **ISO-NE** both run a lossless production cost model. They treat the measured reduction in transmission system losses as a reduction in load, a proxy method to calculate the impact on production costs. **PJM** is proposing to use this same method for Order 1920 compliance.
- **SPP** calculates the value of reduced losses by directly capturing the difference in LMPs on either side of transmission lines and multiplying that by the measured reduced losses given the electrical parameters of the transmission line. **SERTP** has a similar method using the marginal dispatch cost at each location since LMPs are not calculated in the Southeast.
- As with Benefit #3, **NorthernGrid** bases their existing benefit on increased generation sales, putting greater emphasis on increasing transmission provider revenues. They propose to use APC savings for long-term planning instead of generator sales.

Inclusion of imports and interregional in modeling more accurately assesses transmission benefits.

- While not required by Order 1920, the inclusion of interregional transmission in PCM better captures system characteristics.
- **SPP** includes imported generation and losses across interregional transmission lines for this benefit. **PJM** is proposing to do the same across all its long-term planning benefits.

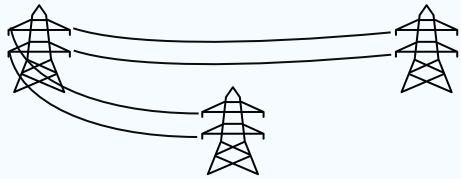
Order 1920 Benefit #7 - Capacity cost benefits from reduced peak energy losses

| | | | | | |
|------------------------------|---|----------------------------|--------------------------------|-----------------------|-------------|
| Description | Reduced generation capacity investments needed to meet peak demand given an expanded transmission network. | | | | |
| Potential Method | Difference in generation capacity needed to makeup system losses during peak demand hour between the base and change cases. | | | | |
| Measurement | Generation Production | Generation Capacity | Unserved Energy | Transmission Capacity | |
| Grid Conditions | Typical | Stress | | | |
| Resource Availability | Transmission Outages | Generation Outages | | | |
| Sampling Fidelity | All hours in year | Peak demand hour(s) | Critical stress hour(s) | | |
| Monetization | Production Cost [\$] | CONE [\$/kW-yr] | VOLL [\$/MWh] | Tx Cost [\$/kV-mi] | MC [\$/MWh] |

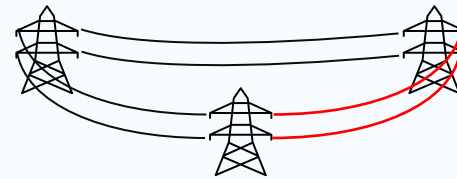
(Order 1920 requires peak, but better to use critical stress hours)

Avoided capacity investments =

$$[\text{Generator capacity of } TC_0 - \text{Generator capacity of } TC_1] \times \text{Cost of New Entry}$$



Base Case



Change Case

| TC_0 Typical Conditions | SC_0 Stress Conditions | TC_1 Typical Conditions | SC_1 Stress Conditions |
|--|--|--|--|
| TC_0^{N-x} Transmission Outage Profile | SC_0^{N-x} Transmission Outage Profile | TC_1^{N-x} Transmission Outage Profile | SC_1^{N-x} Transmission Outage Profile |
| TC_0^{RA} Generator Outage Profile | SC_0^{RA} Generator Outage Profile | TC_1^{RA} Generator Outage Profile | SC_1^{RA} Generator Outage Profile |

Examples from regional planners

| Region | Benefit | Description | Method | Monetization |
|--------|---|--|--|------------------------------------|
| MISO | Capacity savings from reduced losses | Benefit from reduced transmission system losses from the addition of new transmission facilities. The increase in transmission capacity reduces the effective system impedance and redistributes flows from resources across the footprint to the load centers, lowering losses. | LOLE evaluation used to determine the change in RTO-wide planning reserve margin requirements between the base and change cases given reduction in transmission losses. Capacity expansion model used to determine resources needed to meet both cases' PRM. | Generation capacity costs (\$) |
| CAISO | Transmission loss saving | The reduction of transmission losses also introduces capacity benefit in a system that potentially has capacity deficit. | Using PCM, either reduce the peak demand equivalent to the difference in system transmission losses between base and change case so that the need for generation capacity in the peak hours reduces OR increase the net qualified capacity for the existing generation resources equivalent to the difference in system losses. | Determined on a case-by-case basis |
| PJM | <i>Proposal:</i> Capacity cost benefits from reduced energy losses | Less capacity needed for 1-in-10 with reduced losses (pairs with Benefit #4). | Difference in EUE between base and change case from PCM run used to evaluate benefits under normal conditions. | Value of lost load (\$/MWh) |
| SPP | Capacity savings from reduced on-peak losses | Reduced costs from avoided generation investment otherwise required for system transmission losses that are now reduced given expanded system. | Difference in transmission losses between base and change cases multiplied by 112% factor to account for 12% RTO capacity margin. | Net CONE (\$/kW-yr) |
| SERTP | <i>Proposal:</i> Capacity cost benefits from reduced energy losses | Cost savings associated with regional facility that reduce peak system losses, thereby reducing the amount of reserve capacity needed on-peak. | Difference in system transmission losses between base and change cases during peak load hour. Measured using AC power flow model. | Capacity costs (\$) |

Summary and implications of different benefit evaluation methodologies

This benefit measures a reduction in generation capacity given reduced losses, which may not be equivalent to the reduced losses themselves.

- **MISO** uses a capacity expansion model to determine the amount of generation capacity needed to meet a lowered PRM resulting from reduced losses. The capacity expansion model will calculate capacity costs directly.
- **CAISO** and **PJM** will use a production cost model to determine the change in generation needed during peak load hour given reduced losses. This proxy estimate for generation capacity is like the two options FERC introduced for Benefit #2.
- Rather than modeling the change in generation or production needed at peak load hour, **SPP** and **SERTP** assume the change in transmission system losses are equivalent to the reduction in capacity needed to meet peak demand. This assumption may be inaccurate.

Peak load hour may no longer be the hour of highest system losses and therefore may underestimate this benefit.

- Developments in resource adequacy modeling has shown that peak demand hour is no longer the hour of greatest grid stress and therefore may no longer be the hour of greatest system losses. Evaluating this metric at the hour of greatest system losses in the base case—whether that falls on peak demand hour or not—will better capture the full value of this benefit while also including the capacity needed to make up losses during peak hour (and therefore remaining compliant with Order 1920).
- **MISO's** approach negates this difference by looking at the generation needed to meet a reduced planning reserve margin directly. This approach will capture reduced capacity costs during peak load hour *and* other critical stress hours.
- **CAISO, SPP, PJM** and **SERTP** will measure the benefit at peak load hour.

Order 1920 Benefit #2 - Reduced costs related to resource adequacy

Description

Enhanced power system reliability from *either*

- a) reducing loss of load, or
- b) reducing generation needed to maintain loss of load expectation.

Potential Method

Difference in *either*

- a) unserved energy, or
- b) generation capacity needed to meet generation reserve requirement between the base and change cases.

Measurement

Generation Production

Generation Capacity ^b

Unserved Energy ^a

Transmission Capacity

Grid Conditions

Typical

Stress

Resource Availability

Transmission Outages

Generation Outages

Sampling Fidelity

All hours in year

Peak demand hour(s)

Critical stress hours

Monetization

Production Cost [\$]

CONE [\$/kW-yr] ^b

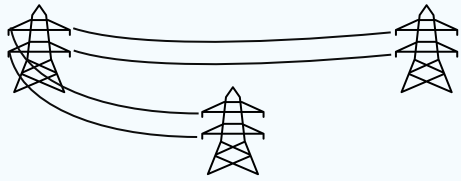
VOLL [\$/MWh] ^a

Tx Cost [\$/kV-mi]

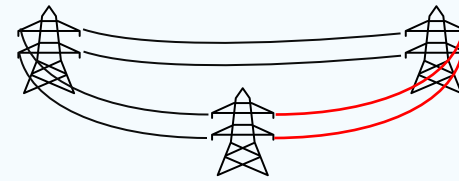
MC [\$/MWh]

a) Avoided unserved energy =

$$[\text{Unserved energy of } TC_0^{RA} - \text{Unserved energy of } TC_1^{RA}] \\ \times \text{Value of Lost Load}$$



Base Case

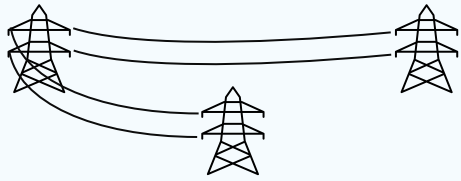


Change Case

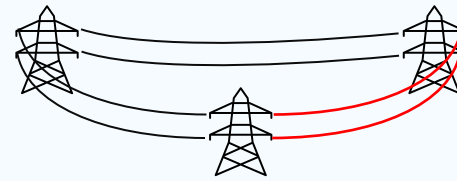
| | | | | | | | |
|--------------|-----------------------------|--------------|-----------------------------|--------------|-----------------------------|--------------|-----------------------------|
| TC_0 | Typical Conditions | SC_0 | Stress Conditions | TC_1 | Typical Conditions | SC_1 | Stress Conditions |
| TC_0^{N-x} | Transmission Outage Profile | SC_0^{N-x} | Transmission Outage Profile | TC_1^{N-x} | Transmission Outage Profile | SC_1^{N-x} | Transmission Outage Profile |
| TC_0^{RA} | Generator Outage Profile | SC_0^{RA} | Generator Outage Profile | TC_1^{RA} | Generator Outage Profile | SC_1^{RA} | Generator Outage Profile |

b) Avoided generation capacity =

$$[\text{Generation capacity of } TC_0^{RA} - \text{Generation capacity of } TC_1^{RA}] \times \text{Cost of New Entry}$$



Base Case



Change Case

| | | | | | | | |
|--------------|-----------------------------|--------------|-----------------------------|--------------|-----------------------------|--------------|-----------------------------|
| TC_0 | Typical Conditions | SC_0 | Stress Conditions | TC_1 | Typical Conditions | SC_1 | Stress Conditions |
| TC_0^{N-x} | Transmission Outage Profile | SC_0^{N-x} | Transmission Outage Profile | TC_1^{N-x} | Transmission Outage Profile | SC_1^{N-x} | Transmission Outage Profile |
| TC_0^{RA} | Generator Outage Profile | SC_0^{RA} | Generator Outage Profile | TC_1^{RA} | Generator Outage Profile | SC_1^{RA} | Generator Outage Profile |

Examples from regional planners: (a) Avoided unserved energy

| Region | Benefit | Description | Method | Monetization |
|--------------|---|---|--|---|
| ISO-NE | Reduction in expected unserved energy | Multiple weather years and outages per year will be simulated to calculate expected unserved energy and its associated economic benefit. | Difference in EUE between base and change cases using zonal probabilistic resource adequacy model. | VOLL of \$3,500/MWh |
| SPP | <i>Proposal:</i> Reduced expected unserved energy | With new transmission, energy can be routed more efficiently to reduce or avoid load shed/unserved energy. | <i>Proposed option (1 of 3):</i> • Calculate change in EUE for base and change cases. | VOLL (\$/MWh) |
| PJM | <i>Proposal:</i> Reduced load shedding | Calculate economic value of reduced unserved energy with more robust transmission. | Difference in EUE between base and change case using PCM tools. | VOLL (\$/MWh) |
| NYISO | <i>2019 PPTP:</i> Capacity market benefits from reliability <i>2023 PPTP:</i> Capacity benefit | <i>2019 PPTPP:</i> Benefit of having a more reliable system. <i>2023 PPTPP:</i> Evaluated the incremental capacity benefits of expanded transmission system. | Difference in LOLE between base and change case. | Cost of Reliability Improvement (CRI) measured in units of \$/0.001 LOLE. The CRI is calculated based on the compensation that a generator would receive in the capacity market for providing such reliability. |
| West Connect | <i>Proposal (1 of 2):</i> Reduced loss of load probability | Reduction in the frequency of power outages in TP territory as a result of the construction of the proposed facility. | Difference in LOLE between base and change case. | Not yet described, but presumably a \$/LOLE multiplier |

Examples from regional planners: (b) Avoided generation capacity

| Region | Benefit | Description | Method | Monetization |
|---------------|---|---|--|---|
| MISO | Avoided capacity costs | Reflects the capital cost savings from the increase in transmission capability provided by transmission expansion, enabling access to resources over the wider MISO footprint. | Use RA modeling and LOLE to determine the change in RTO-wide planning reserve margin between the base and change cases. Run incremental capacity expansion model that reflects the increase in PRM without the portfolio and calculate the cost of additional capacity. System transmission losses are excluded. | Generation capacity costs (\$) |
| ISO-NE | Avoided capital cost of local resources needed to serve demand | Reductions in capital costs for future resource development by being able to access or develop resources in other parts of the system, rather than developing resources in constrained parts of the system. | Difference in zonal capacity expansion modeling between base and change cases to see what generation is offset. Uses capacity expansion modeling. | Generation capacity + fixed operating costs (\$) |
| PJM | Reliability Pricing Model benefit | Reduction in capacity market prices. | Difference in capacity market clearing results with and without proposed facility. Sum of change in system capacity costs and zonal load capacity payments. | Capacity market clearing costs (\$) + Load capacity payments (\$) |
| SPP | <i>Proposal:</i> Reduced expected unserved energy | With new transmission, energy can be routed more efficiently to reduce or avoid load shed/unserved energy. | <i>Proposed option (2 of 3):</i> <ul style="list-style-type: none"> Calculate change in EUE for base and change cases; add capacity to base case until EUE matches the change case. | Net CONE (\$/kW-yr) |
| NYISO | <i>2019 PPTPP:</i> Capacity market benefits from generation investment cost savings | Reduced need to build more generation to maintain resource adequacy. | Difference in generation capacity needed to maintain 1-day-in-10-years LOLE resource adequacy in all zones. | Net CONE (\$/kW-yr) |
| CAISO | Local capacity requirement benefit | Reduction in need for contracts with local generators to meet local capacity requirement (LCR). | Difference in LCR (local capacity construct; not equivalent to PRM or LOLE) between change and base case. LCR studies are performed outside of PCM simulations. | System and local RA prices are determined by the CPUC (\$) |
| Northern Grid | <i>Proposal (1&2 of 2):</i> i. Reduced loss of load probability, or ii. Reduced planning reserve margin | i. Reduced loss of load probability for resource adequacy planning, which typically includes the consideration of normal system conditions. ii. Reduction in capital costs of generation needed to meet resource adequacy requirements (i.e., planning reserve margins) while holding loss of load probability constant. | Measure change in generation needed to meet either i) loss of load probability target or ii) PRM. TPs will choose the preferred method at the beginning of each long-term planning cycle. | Levelized capital cost (\$/kW-yr) |
| West Connect | <i>Proposal (2 of 2):</i> Reduced planning reserve margin | Reduction in capital costs for generation needed to be built by the TP to meet planning reserve margins as a result of the construction of the proposed facility. | Difference in generation capacity needed to maintain 1-day-in-10-years LOLE. | Not yet described, but likely capacity costs |

Examples from regional planners: Other methods

| Region | Benefit | Description | Method | Monetization |
|--------|---|--|--|--|
| CAISO | Resource adequacy benefit from incremental importing capability | A transmission upgrade can provide RA benefit to overcome a capacity shortfall realized when the upgrade increases the import capability and the cost of capacity is lower for the exporting region. | Difference in import capability between change and base case. | Difference in capacity cost (\$) of marginal unit between importing and exporting region |
| SPP | <i>Proposal:</i> Reduced expected unserved energy | With new transmission, energy can be routed more efficiently to reduce or avoid load shed/unserved energy. | <i>Proposed option (3 of 3):</i> <ul style="list-style-type: none"> Evaluate change in emergency procurements for base and change cases and multiply by LMPs during critical hours. | LMP (\$/MWh) |

Summary and implications of different benefit evaluation methodologies

While both evaluation methods are valid, one or the other may offer unique efficiencies to regional planners based on their other modeling needs and choices.

- **All** regional planners **except ERCOT** either currently use or are considering using the avoided generation capacity method (Option 2b) to evaluate Benefit #2.
- **PJM** currently uses this method but plans to switch to avoided unserved energy method for computational efficiency.

Use of unserved energy, instead of just LOLE, would better capture the full resource adequacy benefits of transmission.

- While allowed by Order 1920, use of loss of load probabilities (such as LOLE) only emphasizes planning for reduced frequency of outages, and not for reduced magnitude or duration of those outages.
- **NYISO, WestConnect, NorthernGrid, and FRCC** currently use or are considering evaluation based only on loss of load probabilities, while **ISO-NE, SPP, and PJM** are considering using expected unserved energy.

Several planners use multiple RA metrics in existing benefits evaluation. Double counting must be avoided for Order 1920.

- **CAISO, ISO-NE, and NYISO** have used multiple metrics like Benefit #2 in their existing planning processes. **ISO-NE** notes that it will justify to FERC why its two methods are not double counting the benefit.
- **NorthernGrid, WestConnect, SERTP, and FRCC** are proposing both benefit evaluation options in their long-term planning, with intention to choose between the two methods at the beginning of the planning cycle.

Inclusion of imports and interregional in modeling more accurately assesses transmission benefits.

- In addition to avoided capacity, **CAISO** calculates the reduced costs of maintaining RA given increased import capability. Though not required by Order 1920, this practice more accurately captures the resource adequacy benefit of transmission.

Order 1920 Benefit #6 - Mitigation of extreme weather events and unexpected system conditions

Description

Reduced cost of generating electricity and loss of load during extreme weather events and unexpected system conditions, including the value of interregional transfer capability.

Potential Method

Difference in

- production costs between base and change cases (including transmission losses) under stress conditions, *and*
- unserved load between the base and change cases under stress conditions.

Measurement

Generation Production ^a

Generation Capacity

Unserved Energy ^b

Transmission Capacity

Grid Conditions

Typical

Stress

Resource Availability

Transmission Outages

Generation Outages

Sampling Fidelity

All hours in year

Peak demand hour(s)

Critical stress hours

Monetization

Production Cost [\$] ^a

CONE [\$/kW-yr]

VOLL [\$/MWh] ^b

Tx Cost [\$/kV-mi]

MC [\$/MWh]

Order 1920 Benefit # 6 - Mitigation of extreme weather events and unexpected system conditions

Reduced...

- a) **cost of generating electricity** and
- b) **loss of load**

Combination of two monetized benefits

during...

- i. **extreme weather events**
- ii. **unexpected system (transmission) conditions**
- iii. **unexpected system (generation) conditions**

Calculated under multiple system conditions

... including the value of interregional transfer capability

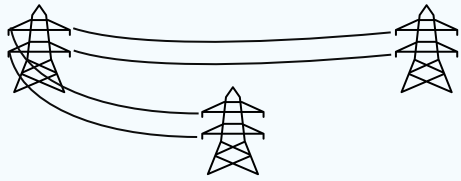
Input data must include existing & future imports/exports

(really should do this for all benefits)

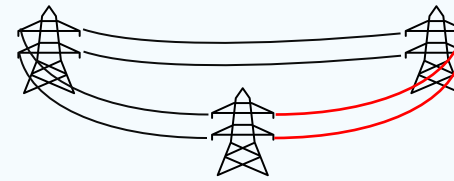
Avoided production cost + avoided unserved load under stress conditions =

$$\{ [\text{Production costs of } (SC_0 + SC_0^{N-x} + SC_0^{RA}) - \text{Production costs of } (SC_1 + SC_1^{N-x} + SC_1^{RA})] + [\text{Unserved energy of } (SC_0 + SC_0^{N-x} + SC_0^{RA}) - \text{Unserved energy of } (SC_1 + SC_1^{N-x} + SC_1^{RA})] \times \text{Value of Lost Load} \} \times \eta$$

(derate equivalent to expected frequency of events)



Base Case



Change Case

| | | | | | | | |
|--------------|-----------------------------|--------------|-----------------------------|--------------|-----------------------------|--------------|-----------------------------|
| TC_0 | Typical Conditions | SC_0 | Stress Conditions | TC_1 | Typical Conditions | SC_1 | Stress Conditions |
| TC_0^{N-x} | Transmission Outage Profile | SC_0^{N-x} | Transmission Outage Profile | TC_1^{N-x} | Transmission Outage Profile | SC_1^{N-x} | Transmission Outage Profile |
| TC_0^{RA} | Generator Outage Profile | SC_0^{RA} | Generator Outage Profile | TC_1^{RA} | Generator Outage Profile | SC_1^{RA} | Generator Outage Profile |

Examples from regional planners

| Region | Benefit | Description | Method | Monetization |
|--------------|---|--|---|---|
| MISO | Reduced risk from extreme weather impacts | Reflects the value of reducing the risk of expected unserved energy during periods of expected supply deficiency attributed to extreme weather conditions. | Difference in EUE between base and change cases for the top 20% (350 events) of historic extreme event scenarios. | VOLL (\$/MWh) |
| SPP | <i>Proposal:</i> Reduced risk from extreme weather and unexpected system conditions | Mitigation of extreme weather events and unexpected system conditions based upon the calculation of the reduction in production costs during extreme weather events and unexpected system conditions, including the benefits associated with any increase in interregional transfer capability that a portfolio of projects may provide during an extreme weather event. | Difference in <ul style="list-style-type: none"> Production costs using PCM, Load shed using AC nodal powerflow, and Interregional transfers using voltage constrained nodal powerflow ... between base and change cases under stress conditions. Stress conditions defined as 20% worse historic events, characterized by magnitude and rate of loss. | Full monetization still under consideration |
| PJM | <i>Proposal:</i> Mitigation of extreme weather events and unexpected system conditions | Same as RA method in Benefit #2 and PCM methods in Benefits #3 - #5, but with more extreme events added over 1000+ hours. | Difference in <ul style="list-style-type: none"> Production costs, and EUE associated with increased transfers ...between base and change cases. Will account for correlation between supply and demand variables via Monte Carlo simulations to determine stress events. Stress conditions to include extreme weather, fuel availability or high fuel costs, and forecast errors. Will include imports from all neighbors. | <ul style="list-style-type: none"> APC (\$) VOLL (\$/MWh) |
| SERTP | <i>Proposal:</i> Mitigation of extreme weather/unexpected events | Fuel and variable operations and maintenance cost savings and reduced loss of load associated with facility that provides access to less expensive and available generation during extreme weather or other unexpected system conditions. | Difference in <ul style="list-style-type: none"> Production costs using PCM, and EUE using RA modeling ... between base and change cases during a set of extreme events / unexpected generation outages and only for stress hours. | <ul style="list-style-type: none"> APC (\$) VOLL (\$/MWh) |
| West Connect | <i>Proposal:</i> Mitigation of extreme weather events and unexpected system conditions | Reduction in production costs to the TP during extreme weather events and unexpected system conditions, such as unusual weather conditions, fuel shortages, and generation and transmission outages, due to a proposed facility. | Difference in production costs between base and change cases. | APC (\$) |

Summary and implications of different benefit evaluation methodologies

All regional planners must update their benefit evaluations to align with Order 1920 requirements for Benefit #6.

- **MISO** is the only regional planner that currently considers extreme events in its near-term benefit evaluation.
 - MISO's current methodology must be updated to include avoided production costs, outage conditions given extreme weather events, and interregional transfers to comply with Order 1920.
- **NYISO** considers transfer capability and operability improvements given different system outage conditions during solution selection but does not monetize as a benefit.
- **WestConnect** currently considers system behavior under extreme events when screening potential transmission solutions. WestConnect's current proposal for long-term planning includes reductions in production costs but omits reductions in unserved energy as required by Order 1920.

Best practice for developing unexpected conditions and extreme events would include scaling historical events for future generation, load, and climatic conditions.

- **MISO, CAISO, WestConnect** and **SPP** are considering developing extreme events based on specific historic events.
- **PJM** is considering developing future extreme events that reflect potential load shed events using Monte Carlo simulations based on past system behavior.

Regional planners must be careful not to omit transmission losses from the evaluation of Benefit #6. Doing so would underestimate the benefit.

- Order 1920 requires losses be disaggregated from Benefits #2 and #3 – and instead be captured in Benefits #7 and #4, respectively – but not for Benefit #6.

Order 1920 Benefit #1 - Avoided or deferred reliability transmission facilities and aging infrastructure replacement

Description

Reduced costs achieved by delaying or avoiding local transmission facilities additions/upgrades to address reliability needs and replace aging infrastructure.

Potential Method

- Capital costs of existing and planned transmission facility replacements—as prescribed by local utilities—that are deferred or avoided from the added candidate facility(ies), and
- Comparison of future thermal overloads in base and change cases.

Measurement

Generation Production

Generation Capacity

Unserved Energy

Transmission Capacity

Grid Conditions

Typical

Stress

Resource Availability

Transmission Outages

Generation Outages

Sampling Fidelity

All hours in year

Peak demand hour(s)

Critical stress hours

Monetization

Production Cost [\$]

CONE [\$/kW-yr]

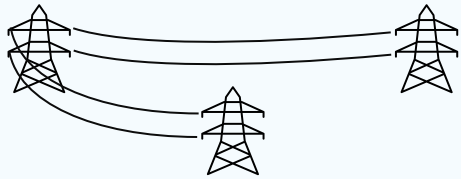
VOLL [\$/MWh]

Tx Cost [\$/kV-mi]

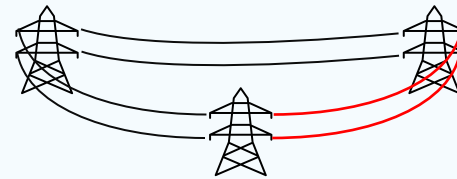
MC [\$/MWh]

Avoided facility upgrades =

$$\{ [\text{Asset condition upgrades in } TC_0 - \text{Asset condition upgrades in } TC_1] + [\text{Thermal overloads in } TC_0 - \text{Thermal overloads in } TC_1] \} \times \text{Tx Costs}$$



Base Case



Change Case

| TC₀ | Typical Conditions | SC₀ | Stress Conditions | TC₁ | Typical Conditions | SC₁ | Stress Conditions |
|-------------------------------------|-----------------------------|-------------------------------------|-----------------------------|-------------------------------------|-----------------------------|-------------------------------------|-----------------------------|
| TC₀^{N-x} | Transmission Outage Profile | SC₀^{N-x} | Transmission Outage Profile | TC₁^{N-x} | Transmission Outage Profile | SC₁^{N-x} | Transmission Outage Profile |
| TC₀^{RA} | Generator Outage Profile | SC₀^{RA} | Generator Outage Profile | TC₁^{RA} | Generator Outage Profile | SC₁^{RA} | Generator Outage Profile |

Examples from regional planners: Existing transmission asset lists

| Region | Benefit | Description | Method | Monetization |
|---------------|---|--|--|--|
| MISO | L RTP Tranche 1: Avoided transmission investment | Costs for age and condition replacement of transmission facilities are offset by rebuilds and co-location of proposed facilities along existing rights-of-way. | Identify aging transmission facilities in the proposed right-of-way that would need to be replaced within next 20 years. | Transmission exploratory costs (\$/kV-mi) |
| NYISO | 2019 PPTP: Replacement of aging equipment | Avoided capital cost/refurbishment cost and operations and maintenance costs of aging infrastructure and/or mileage of- infrastructure replaced. | Engineering firm looked at entire system to determine which facilities could be decommissioned given the selected portfolio. | Both <ul style="list-style-type: none"> Overnight capital costs of similar equipment O&M costs set at 2.85% of overnight capital |
| ISO-NE | Avoided transmission investment | The avoided transmission investment will determine the costs of reliability, market efficiency, and aging infrastructure replacements that would no longer be needed or would be replaced by the proposal. | Proposed facility counts if it eliminates need for reliability, public policy, or market efficiency facility on preexisting reliability or asset condition list or if the replaced elements are more than 40 years old. | Either <ul style="list-style-type: none"> Known capital costs of specific facilities (\$) Transmission exploratory costs (\$/kV-mi) |
| Northern Grid | Deferred costs and Avoided capital costs | The projected avoided costs of deferred or eliminated transmission facilities for an enrolled TP that are directly attributable to regional facility. | The revenue requirement avoided over each year of deferral period / or lifetime of the asset. Deferred and avoided facilities could be asset condition or reliability-based. | Avoided annual revenue to the TP for specific facility, including annual return (both debt and equity), depreciation, taxes, O&M expenses |
| FRCC | Total estimated avoided and alternative project costs | The avoided costs for each enrolled TP that has one or more facilities—planned or alternative—being displaced by a regional facility. | Independent consultant will determine if any enrolled TP's planned or alternative facilities will be displaced. Displaced facilities could be asset condition or reliability-based. Cost of local projects necessary to support either the displaced or proposed project are included. | Either <ul style="list-style-type: none"> Known costs of specific facilities Expected costs of alternative project Value of benefit is adjusted for any local upgrade costs that are either displaced by or needed to support the regional facility. |
| SERTP | Displaced transmission projects | Reduced transmission expenditures achieved when regional facility avoids or defers proposed or planned local transmission facilities that are otherwise needed for system reliability. | Use AC power flow model on change case to determine if any local facilities are no longer needed (i.e., overloads resolved) given list of local transmission assets provided by TP. Displaced facilities could be age- or reliability-based. | Known costs of specific facilities. Value of benefit is reduced by additional local upgrade costs needed to support the regional facility. |
| PJM | Avoided or deferred transmission | Avoided in-kind replacements; avoided or deferred lower kV investments; avoided or deferred future transmission investments; reduced re-builds. | Displaced projects will be identified from approved / in-kind replacement lists (generally 10-yr asset lists). | Capital cost of displaced project |

Examples from regional planners: Modeling future thermal overloads

| Region | Benefit | Description | Method | Monetization |
|--------------|---|--|--|---|
| MISO | <i>L RTP Tranche 1:</i> Avoided transmission investment | Captures the avoided cost of reliability upgrades and replacements that will not be required in the future as a result of the addition of proposed facilities. | Difference in future thermal loading of all system lines in base and change cases and identify lines where thermal rating exceedance is solved by proposed facilities. Assume parallel transmission facilities needed to address overload. | Transmission exploratory costs (\$/kV-mi) |
| MISO | <i>L RTP Tranche 2:</i> Mitigation of reliability issues | Reliability benefits monetize the avoided risk of unserved load that would otherwise occur if system performance criteria are not met. | Difference in EUE between base and change cases given thermal and voltage overloads resulting from NERC TPL contingencies P1, P2, and P7 under typical conditions. | VOLL sensitivities (\$3,500/MWh & \$10,000/MWh) to get range of results |
| ISO-NE | Avoided transmission investment [Same as previous] | The avoided transmission investment will determine the costs of reliability, market efficiency, and aging infrastructure replacements that would no longer be needed or would be replaced by the proposal. | Difference in thermal overloads in future years 10 and 20 to identify any overloads that are resolved by proposed portfolio. Assume parallel transmission facilities needed to address overload. | Either <ul style="list-style-type: none"> Known capital costs of specific facilities (\$) Transmission exploratory costs (\$/kV-mi) |
| SPP | Avoided or delayed reliability facilities | Benefit monetizes the reliability benefit as the avoided cost of not having to build a separate reliability facility. | Difference in thermal reliability needs between the base and change cases. Isolate those reliability issues which change case solves and apply a new circuit or transformer in parallel to the thermal reliability issue. | Either <ul style="list-style-type: none"> Known capital costs of specific facilities (\$) Transmission exploratory costs of parallel equipment (\$/kV-mi) |
| CAISO | Avoided cost of other facilities | If a reliability or policy facility can be avoided because of the economic facility under study, then the avoided cost contributes to the benefit of the economic facility. | Full assessment of the benefit from avoided costs is on a case-by-case basis. Given sequential study approach (reliability -> policy -> economic) both reliability and age-based replacements are considered in analysis. | Determined on a case-by-case basis. |
| West Connect | Avoided cost of local transmission solutions (Reliability) | Benefit of regional project which resolves NERC TPL violation(s) on multiple enrolled TP's facilities is related to the displaced local reliability project. | Enrolled TPs submit alternative local solutions to the reliability violation. The cost of these local solutions will be compared to costs of the selected regional solution. | Net present value of projects that would be avoided (\$) |

Summary and implications of different benefit evaluation methodologies

Regional planners must update their metrics to consider both age- and reliability-based avoided assets

- **MISO, ISO-NE, NorthernGrid, FRCC, and SERTP** analyze both age-based and reliability-based local asset replacements in their current benefit evaluations, aligned with Order 1920.
- **NYISO** currently only considers age-based retirements, while **SPP, WestConnect, and CAISO** consider only displaced reliability-based facilities.

Use of local asset lists alone will not be sufficient for long-term planning and must be supplemented with modeling.

- These lists usually only include a transmission provider's 5- or 10-year replacement plans. It is best to supplement these lists with reliability modeling for a more complete benefit evaluation.
- **NYISO, NorthernGrid, FRCC, SERTP, and PJM** currently and/or propose to consider deferred/avoided transmission benefits based on existing local transmission asset lists.
- **MISO, ISO-NE, SPP, and CAISO** model future system overloads on the base and change cases to estimate what local facilities would need to be built to resolve the future overloads.
 - **ISO-NE, SPP, and CAISO** only model future thermal overloads, while **MISO** additionally considers voltage overloads, providing a more complete picture of future local reliability issues needing to be resolved.
 - **SERTP** uses AC power flow modeling, which—if applied to future cases and not just existing asset lists—would enable them to estimate a full suite of future reliability issues and avoided local facilities.

Order 1920 Benefit #8 - Other benefits not considered by Order 1920

Description

“However, we recognize that Long-Term Regional Transmission Facilities may provide additional benefits that may merit consideration when transmission providers are identifying, evaluating, and selecting such facilities to address Long-Term Transmission Needs more efficiently or cost-effectively. Therefore, transmission providers may measure and use additional benefits beyond those included in the required set of benefits...” – Order 1920 P822

Measurement

Generation Production

Generation Capacity

Unserved Energy

Transmission Capacity

Grid Conditions

Typical

Stress

Resource Availability

Transmission Outages

Generation Outages

Sampling Fidelity

All hours in year

Peak demand hour(s)

Critical stress hours

Monetization

Production Cost [\$]

CONE [\$/kW-yr]

VOLL [\$/MWh]

Tx Cost [\$/kV-mi]

MC [\$/MWh]

Examples from regional planners: Deliverability Benefits

| Region | Benefit | Description | Method | Monetization |
|--------|---|--|---|--|
| CAISO | Deliverability benefit | Transmission upgrade can potentially increase generator deliverability to the region under study through the directly increased transmission capacity or the transmission loss saving. Similarly to the resource adequacy benefit, such deliverability benefit can only be materialized when there will be capacity deficit in the region under study. | Full assessment performed on case-by-case basis. | Determined on a case-by-case basis |
| SPP | Increased wheeling through and out revenues | Expected increase in wheeling revenues resulting from an increase in exports with neighboring regions. | <p>For firm transfers, find the difference in available transfer capacity (measured using First Contingency Incremental Transfer Capability) on interregional paths between base and change case. Apply the anticipated future exported power.</p> <p>For non-firm transfers, use PCM with hurdle rates to estimate the expected amount of increased exported energy.</p> | <p>Firm: Long-term wheeling service (\$/MW)</p> <p>Non-firm: Non-firm hourly wheeling service (\$/MWh)</p> |
| NYISO | 2023 PPTP: Transfer capability | Increase in transfer capability on a cost / MW of transfer capability basis. | Difference in three important transfer capacity limits (Long Island export interface, offshore wind integration, double outage operability range) between base and change cases. | Normalize cost of facility by the measured transfer capability increase to determine "Cost per MW Ratio" (\$/MW). More of a comparative selection criteria than monetize benefit used in B/C ratio |
| NYISO | 2023 PPTP: Expandability | Number of potential new physical and electrical POIs that could accommodate future system buildout (i.e., OSW). | Combination of two metrics: Count of number of potential POIs for new transmission tie-lines Deliverability (MW) of new generation under N-0, N-1, and N-1-1 conditions given spring and summer conditions | N/A. More of a comparative selection criteria than monetize benefit used in B/C ratio |

Examples from regional planners: Public Policy Benefits

| Region | Benefit | Description | Method | Monetization |
|--------|--|--|--|--|
| CAISO | Public-policy | Transmission facilities can help to reduce the cost of reaching renewable energy targets by avoiding curtailment of existing and facilitating the integration of lower cost renewable resources located in remote area, or by avoiding over-build. | Full assessment performed on case-by-case basis. | Determined on a case-by-case basis |
| CAISO | Renewable integration | As the renewable penetration increases, it becomes challenging to integrate renewable generation. Transmission upgrades help mitigate integration challenges, such as over-supply and curtailment, by allowing sharing of energy and ancillary services among multiple BAAs. | Full assessment performed on case-by-case basis. | Determined on a case-by-case basis |
| SPP | Benefit from meeting public policy goals | Minimum economic benefits produced by public policy-driven transmission facilities, including those that help meet state goals or mandates. | Determine RPS or other public policy regulation/law and share of unmet RPS in each zone. | Benefit set equal to facility cost (B/C assumed equal to 1) and allocate portion of benefit to zones based on share of unmet RPS |
| NYISO | 2019 PPTP: Reduced need for generation in downstate areas | Reduction in capacity needed in high density areas given higher transfer capability. Public Policy requirement. | Combination of two metrics: Difference in... <ul style="list-style-type: none"> Capacity needed to maintain LOLE in downstate zones, and Annual power flows across the upstate/downstate interface ... between base and change case. | <ul style="list-style-type: none"> Generation capacity (\$) Average LMP (\$/MWh) |
| NYISO | 2023 PPTP: Avoided capital cost | Assess the economic benefits related to the reduction and/or deferral of future generation facilities needed to meet projected future energy demand and renewable policy objectives. | Difference in generation capacity between base and change cases given specific factors: <ul style="list-style-type: none"> Reduce OSW curtailment, Increase transfer capability to/from Long Island, and Decrease Long Island capacity reserve requirement. | Installed capacity (\$) from capacity expansion model |

Examples from regional planners: Other Benefits

| Region | Benefit | Description | Method | Monetization |
|--------|--|---|---|---|
| SPP | Assumed benefit of mandated reliability projects | Minimum economic benefits produced by reliability-driven transmission facilities that resolve NERC-defined violations. | Difference in power flow on remaining transmission facilities with reliability facilities taken out of service (change case). Where increased power flow is found, those TPs are considered beneficiaries of the reliability facility. Uses PCM to determine change in flows. | Benefit set equal to facility cost (B/C assumed equal to 1) and allocate benefit to zone based on a combination of its portion of changed power flow share and load ratio share |
| SPP | GRID contributions (GRID-C) | Interconnection customers paying GRID Contributions are benefitting from continued proactive planning regardless of when they enter the interconnection queue | SPP currently debating several methods to include GRID Contributions from interconnection customers into their benefit-to-cost evaluation. The potential methods include quantifying benefits to generators, benefits to loads, and direct inclusion of the GRID-C charge to reduce costs in benefit-to-cost ratio. | Depends on option selected |
| MISO | Decarbonization | Decarbonization benefits relate to avoided CO ₂ emissions that result from the more efficient dispatch of lower-cost resources. | Difference in carbon emissions between -base and change cases. | Product of carbon emissions and social cost of carbon (SCC determined from 3 sources: MN legislation, EPA, IRS 45Q tax credit) |
| NYISO | 2019 PPTPP: Environmental | Reduction in CO ₂ emissions for NYISO and neighboring regions. | Difference in production of CO ₂ emitting generators between base and change cases. Emissions of imported generation also considered. | Emissions allowance cost applied to the generation of CO ₂ emitting generators (\$/MWh) |

Summary and implications of different benefit evaluation methodologies

Several “other” benefits are related to Order 1920 benefits but are measuring benefit beyond that required by the Order. Measurement of additional value would not constitute double counting.

- Many of these increased transfer capability “other” benefits are related to Benefits #2 and #6, but measure impacts beyond the Order 1920 metrics.
- **CAISO, SPP, and NYISO** consider additional benefits for increasing transfer capability, either intra-regionally or with their neighboring regional planners.

Public policy benefits are not explicitly enumerated in Order 1920, and their inclusion enables a more comprehensive multi-value benefit evaluation of transmission.

- **CAISO, SPP, and NYISO** also consider additional benefits for meeting public policy goals. These public policy benefits are specific to either meeting state / utility mandated renewable portfolio standards or reducing generation needs in a particularly constrained location of the grid.
- **WestConnect** also measures capacity cost savings associated with public policy requirements, but only for cost allocation and not for benefits evaluation.
- **NYISO** and **MISO** both measure environmental benefits of proposed transmission, capturing additional value beyond that required by Order 1920.

Challenges to Benefit Quantification

Challenges to benefit quantification

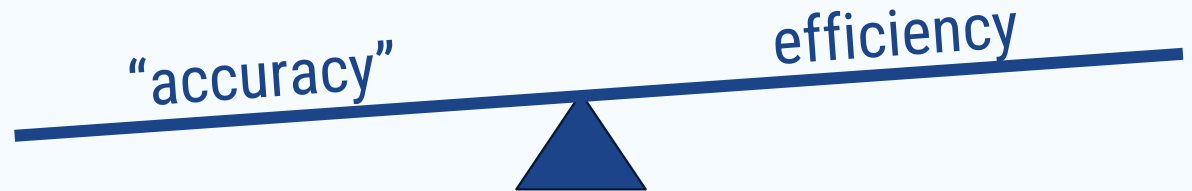
Modeling complexity

Avoiding double counting

Consistent data and methodology

Monetization of benefits

Siloed planning processes



- Must balance increased modeling "accuracy" with efficiency.
 - Increasing the number of power system models, geographic resolution, and future model years all increase computational burden and time.
- Modeling is not a perfect forecast of the future, but good modeling does provide reasonable estimates on which to make good decisions.
- Modelers' Rule of Thumb: Choose only as much complexity as needed to inform decisions. If a modeling choice will not significantly impact the results, omit it.

Challenges to benefit quantification

Modeling complexity

Avoiding double counting

Consistent data and methodology

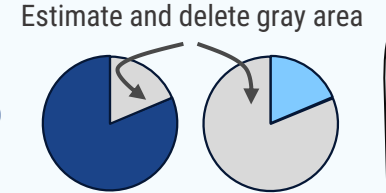
Monetization of benefits

Siloed planning processes

Single model run with allocated individual benefits guarantees avoided double counting



Separate model runs for each benefit requires estimating how much to reduce the final result to avoid double counting



- Order 1920 requires regional planners to avoid double counting. This is methodologically possible to do.
 - Where a single model can be run to quantify benefits (e.g., PCM for Benefits #3 and 4), the resulting total benefits can be allocated to individual metrics.
 - This is easier than running the model separately for each metric and then trying to account for duplicative benefits.
- Care must be taken to avoid duplicative benefits, but without underestimating other benefits.
 - For example, Order 1920 separates losses from production and capacity costs as their own metrics under normal conditions (separating Benefit #4 from #3 and Benefit #7 from #2), but not for under outages of Benefit #5 or stress conditions of Benefit #6.
 - Losses should be included in Benefits #5 and #6 for full benefit evaluation.

Challenges to benefit quantification

Modeling complexity

Avoiding double counting

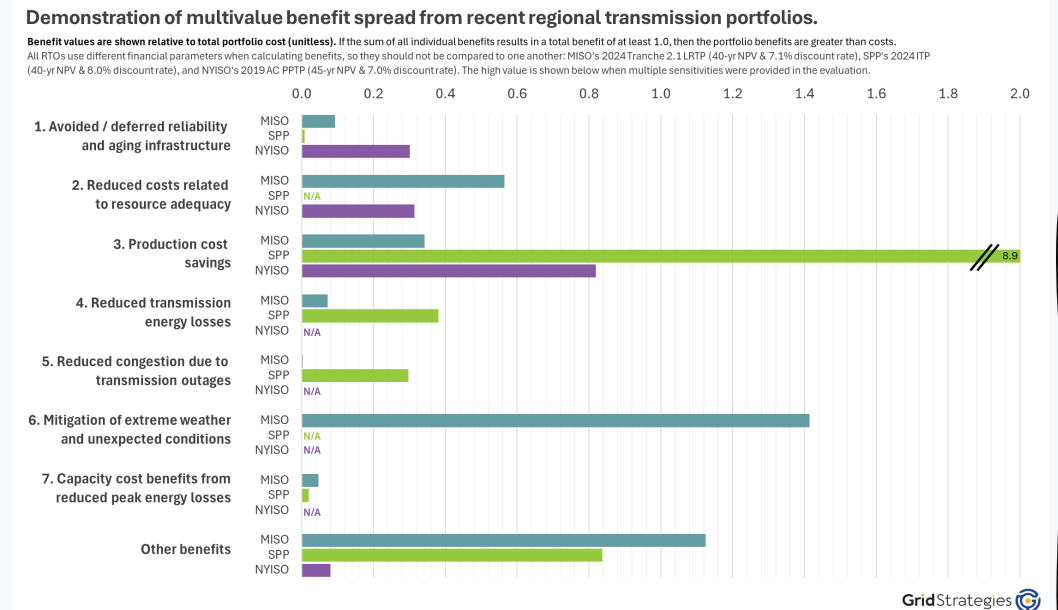
Consistent data and methodology

Monetization of benefits

Siloed planning processes

- Interregional transmission has historically been very difficult to plan given the involvement of multiple regional planners. This type of planning requires agreement on benefit evaluation and cost allocation principles.
- To overcome this challenge, regional planners should align models, inputs, assumptions, and benefit quantification methods with neighboring planning regions early.

The importance of consistent benefit evaluation methods is exemplified in the comparison of recent RTO portfolio benefits: Are differences in benefit valuation due to differences in calculation methods or real characteristics of the portfolios?



Challenges to benefit quantification

Modeling complexity

Avoiding double counting

Consistent data and methodology

Monetization of benefits

Siloed planning processes

- Many benefits (i.e., production costs) are naturally monetized, but not all. How should un-monetized benefits be monetized, if at all?
- Many benefits are difficult to monetize
 - Cost of new entry tied to a single generation type is problematic given the diversity of energy resources now available to meet grid needs.
 - Value of lost load is controversial because it requires putting a price—at least conceptually—on society's tolerance for blackouts, including impacts to human health and life.
- Is consistency across benefits needed? For example, is it ok to use a different VOLL for resource adequacy (#2) and resilience (#6)?
- Is it ok to *not* monetize some benefits? If un-monetized, how can it be included in the required benefit-to-cost evaluation for project selection?
- Decisions on benefit monetization should be made early via stakeholder engagement, ahead of the evaluation process.

Challenges to benefit quantification

Modeling complexity

Avoiding double counting

Consistent data and methodology

Monetization of benefits

Siloed planning processes



- Regional planning organizations often have siloed planning practices, where the transmission planning group may not be familiar with the tools or processes of other groups in the organization.
- This introduces the risk of both inexperience and disjointed planning without coordination. For example:
 - Transmission planners may not have experience running reliability models needed for benefits evaluation.
 - The LOLE model used to determine transmission solution benefits should be aligned with the LOLE model used by the reliability group for their resource adequacy decisions.
- Coordination and interdependent model assumptions should be used across the regional planning organization to ensure consistent planning.

Appendices

Acronyms and common terms

| | |
|-------|---|
| APC | Adjusted Production Costs |
| BAA | Balancing Area Authority |
| BPM | Business Practice Manual |
| CONE | Cost of New Entry |
| EUE | Expected Unserved Energy |
| FCITC | First Contingency Incremental Transfer Capability |
| LMP | Locational Marginal Price |
| LOLE | Loss of Load Expectation |
| NERC | North American Electric Reliability Corporation |
| O1920 | FERC Order 1920 |
| PCM | Production Cost Modeling |
| PRM | Planning Reserve Requirement |
| RA | Resource Adequacy |
| TP | Transmission Provider |
| TPL | Transmission Planning |
| VOLL | Value of Lost Load |

- Reserve margin: An amount of excess generation capacity above expected demand which can be used as a buffer against unexpected conditions. A “tight” reserve margin occurs when excess generation approaches zero and there is risk of demand exceeding supply.
- Typical conditions: Expected grid and weather conditions which align with historic system behavior. There are usually very few outages on the system during typical conditions.
- Stress conditions: Unexpected grid and/or weather conditions that result in reduced capacity to either generate or deliver power to meet load.
- Contingency conditions: Outage of a major transmission and/or generation facility(ies). These conditions usually require more expensive generation to be used to avoid tight reserve margins.
- Resource adequacy event: Any event, often a contingency, resulting in tight reserve margins. These events are usually accounted for in planning when establishing the desired reserve margin.
- Resilience event: A complex event involving multiple outages, unusual load behavior, and weather conditions. These events are more extreme than resource adequacy events and push the system toward or into load loss.
- Peak demand/load hour: Hour of the year with the highest system-wide demand for electricity.
- Critical stress hour: Hour of the year with the tightest reserve margin.

Methodology

This report was created by reviewing all regional planners' existing and draft Tariff changes, Business Practice Manuals, and stakeholder meeting materials as they relate to transmission benefit evaluation.

We extend a huge **THANK YOU** to the utility and RTO staff who reviewed the accompanying spreadsheet on which this report was based, and to more than a dozen colleagues and planning stakeholders who reviewed the report.

We note that only information that was available at the time of publication could be used for this assessment. Order 1920 compliance is an ongoing process for all regional planners and the information contained here will change.

Sources and additional benefit metric details for each regional planner can be found in the accompanying spreadsheet: <https://gridstrategiesllc.com/o1920-benefit-metrics-final/>