

# Regional Transmission Planning

A review of practices following FERC Order Nos. 890 and 1000

## APPENDICES

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November 2017



This work was supported by the U.S. Department of Energy's Offices of Electricity Delivery and Energy Reliability and Energy Policy and Systems Analysis under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

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# **Regional Transmission Planning: A review of practices following FERC Order Nos. 890 and 1000**

## **Appendices**

Prepared for the  
Office of Electricity Delivery and Energy Reliability  
and  
Office of Energy Policy and Systems Analysis  
U.S. Department of Energy

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**November 2017**

LBNL-2001079

This work was supported by the U.S. Department of Energy's Offices of Electricity Delivery and Energy Reliability and Energy Policy and Systems Analysis under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

## Acknowledgements

The work described in this study was funded by the U.S. Department of Energy’s Offices of Electricity Delivery and Energy Reliability (OE) and Energy Policy and Systems Analysis (EPSA). We thank David Meyer, Rakesh Batra, Cynthia Wilson, and Jeanette Pablo for their support.

We thank the following staff and participants in the twelve regional transmission planning entities for participating in interviews we conducted and providing comments on an early draft of the report:

California Independent System Operator (ISO): Neil Millar, Yi Zhang, Terri Moreland  
Columbia Grid: Paul Didsayabutra  
Florida Reliability Coordinating Council, Inc.: Mory Jones, Vince Ordax  
ISO New England: Steve Rourke, Mike Henderson, Al McBride, Brent Oberlin  
Midcontinent ISO: Jeff Webb, John Lawhorn  
New York ISO: John Buechler, Tim Duffy  
Northern Tier Transmission Group: Chelsea Loomis, Sharon Helm, Craig Quist, John Leland  
PJM Interconnection: Paul McGlynn, Chuck Liebold, Nicholae Dumitriu  
South Carolina Regional Transmission Planning: Clay Young, Phil Kleckley, Ashley Cooper  
Southeastern Regional Transmission Planning: Julia York, Josh Pierce, Chris Balmer, Ashley Moore, Nina McLaurin, Patrick McGovern  
Southwestern Power Pool: Lanny Nickell  
WestConnect: Charles Reinhold, Heidi Pacini

We also thank Denis Bergeron, Gregory Carmean, Maury Galbraith, Kevin Porter, and David Whitely for providing comments on an early draft of the report.

Finally, we thank Dana Robson and Nan Wishner for assistance with formatting and editing.

All opinions, errors, and omissions remain the responsibility of the authors. All reference URLs were accurate as of September 1, 2017.

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# Appendix A. California Independent System Operator (CAISO)

## Summary

The California Independent System Operator (CAISO) operates the high-voltage power system and conducts power system planning for 80% of load in the state of California. It also administers a centralized market for wholesale power for the state, which it has augmented through the creation of an energy imbalance market that currently operates across eight western states (with announced intentions by parties in other western states to join in the near future). CAISO conducts planning studies that focus primarily (but not solely) on the identification of three main types of transmission solutions: reliability, public policy, and economic. The economic evaluation of transmission projects, in addition to transmission project cost, considers the potential impact of projects on overall system production costs.

## Background

CAISO was formed in 1997 in response to the passage of the federal Energy Policy Act of 1992, which removed barriers to competition in the wholesale generation of the electricity business. CAISO currently controls the operation of and conducts planning for the transmission assets owned by the three large investor-owned utilities (IOUs) in the state, along with those of smaller utilities in the state and, more recently, in the adjacent state of Nevada. The incumbent transmission project developers (i.e., current transmission owners) within CAISO are known as participating transmission owners (PTOs).

The California-centric focus of CAISO's transmission planning activities involves close coordination and linkages with California energy and regulatory agencies. For example, CAISO relies on load forecasts developed by the California Energy Commission (CEC) for the state as a whole. It also relies on resource procurement outcomes and preferences managed by the California Public Utilities Commission (CPUC) for the three large IOUs. Identification of a transmission solution creates an obligation to construct for the identified transmission developer.

CAISO initiated formal economic analysis of transmission planning activities with the creation of the Transmission Economic Assessment Methodology (TEAM) in 2005. The economic analysis principles and approaches first outlined in TEAM have been refined over time and continue to guide CAISO's economic assessments. Thus, regional transmission planning (including regional cost allocation for projects) by CAISO largely pre-dates Federal Energy Regulatory Commission (FERC) Order No. 890.

FERC Order No. 1000 has resulted in two major changes to CAISO's transmission planning processes. First, CAISO expanded the scope of transmission projects that might be considered in its "competitive solicitation" process to select among non-incumbent and incumbent transmission developers for projects selected for regional cost allocation through an open competitive process. Second, CAISO has now formalized arrangements for interregional transmission coordination with its neighbors.<sup>1</sup>

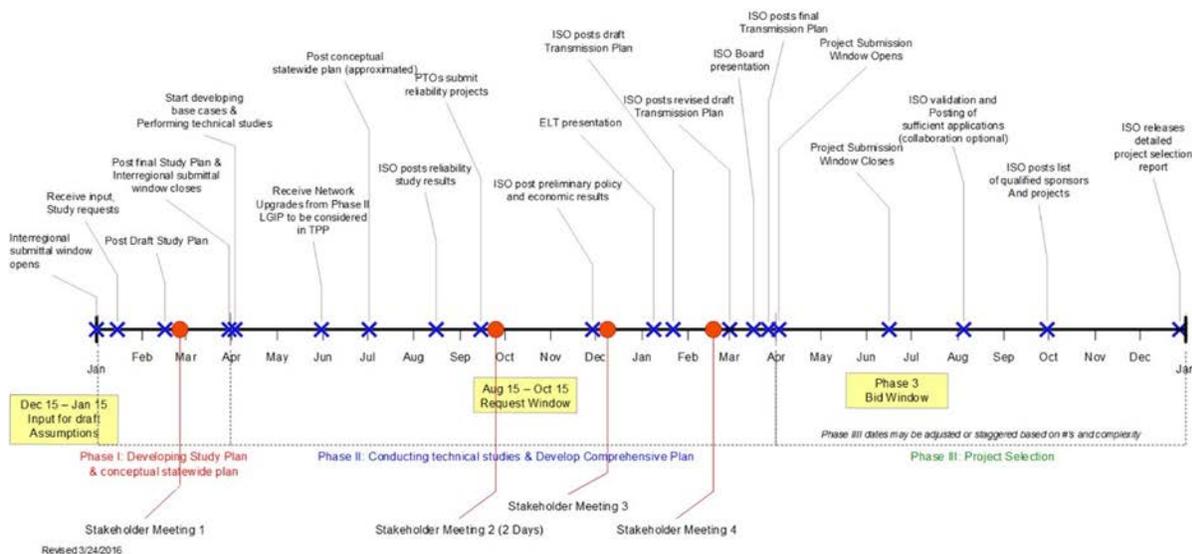
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<sup>1</sup> CAISO's interregional transmission coordination activities are not the focus of this report and are not discussed in this summary.

A third change brought about by FERC Order No. 1000—the consideration of transmission required to meet public policy requirements—has not affected CAISO significantly because public policy considerations (such as those that would manifest themselves through resource procurements guided by the CPUC) were already included in planning process changes that went into effect in 2011. CAISO’s Order No. 1000-compliant regional transmission planning process and cost allocation provisions became effective for the region in October 2013.

## Regional Transmission Planning

CAISO initiates a new, three-phase transmission planning process annually. See Figure A - 1. The planning horizon is ten years into the future. Phase 1 begins in December of each year and ends in April of the following year. Phase 2 starts in April and concludes in approximately March of the following year. The completion of one planning cycle overlaps the initiation of the next planning cycle. Phase 3 is conducted only if transmission solutions are identified that require an open competitive process in order to select a developer.



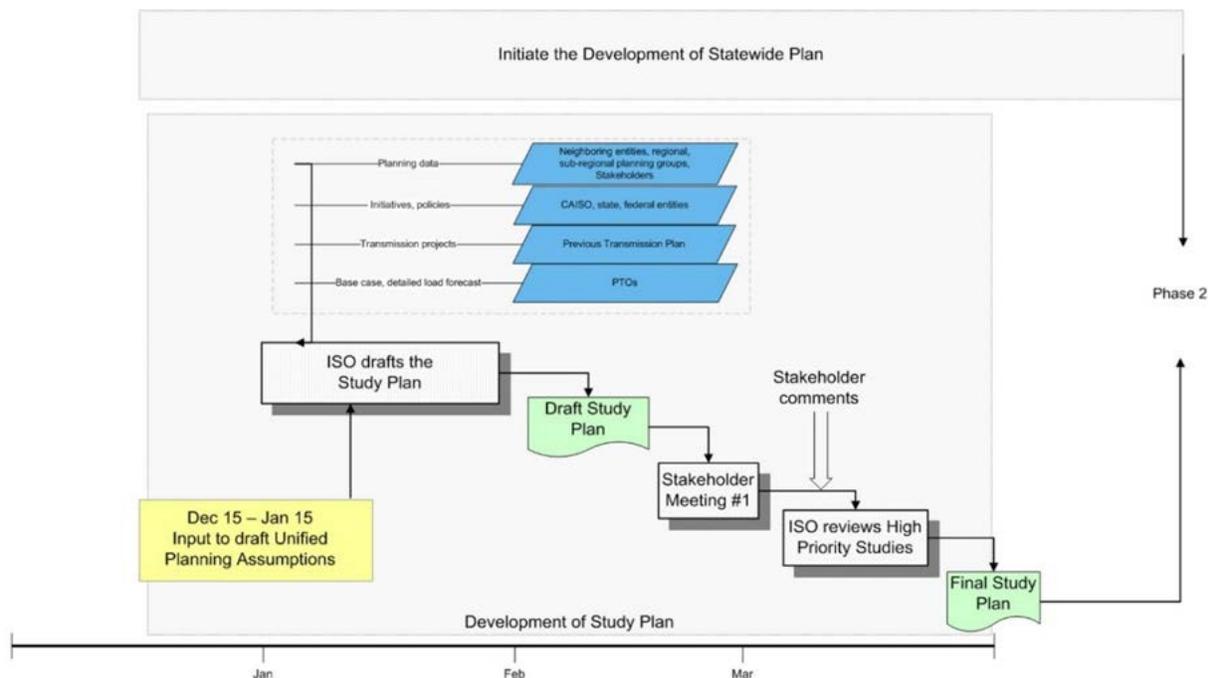
**Figure A - 1. CAISO Transmission Planning Process Timeline**

Source: CAISO (2016b). *Business Practice Manual for the Transmission Planning Process*.

Phase 1 involves the development of study assumptions, models, and study scope. See Figure A - 2. Formulation of the study plan includes stakeholder input to identify the public policies that will be considered in the evaluations conducted in Phase 2. Phase 1 also includes stakeholder (and staff) input on the formulation of up to five economic studies, each of which may lead to the identification of economics-driven transmission solutions in Phase 2.

In addition, Phase 1 initiates the development of the conceptual statewide transmission plan. The conceptual statewide transmission plan represents an integrated, statewide inventory of transmission projects that have been approved by both CAISO (in its previous transmission planning cycle) and by the

other California transmission planning entities. Currently, these entities coordinate their regional transmission planning activities through WestConnect. This inventory is foundational for the studies that are conducted in Phase 2 of CAISO’s transmission planning process.<sup>2</sup>



**Figure A - 2. Overview of Phase I of the CAISO Transmission Planning Process**

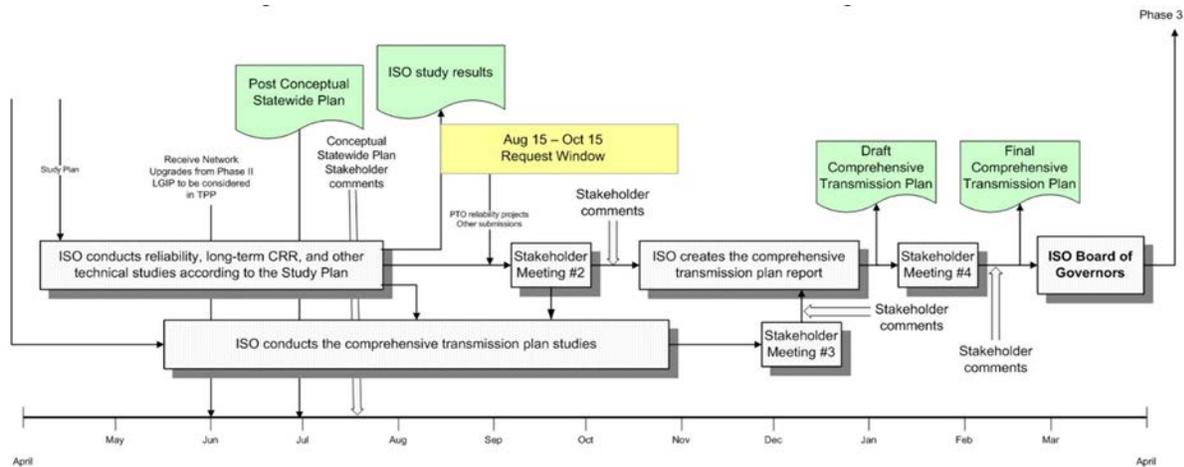
Source: CAISO (2016b). *Business Practice Manual for the Transmission Planning Process*.

Phase 2 of the transmission planning process is centered on conducting the technical studies that lead to the preparation an annual transmission plan that includes identified projects and solutions. See Figure A - 3. Phase 2 involves a sequential set of analysis and evaluation activities that leads to the identification of reliability-, public policy-, and economic-driven transmission solutions, in that order.

With respect to reliability analysis, CAISO is a NERC<sup>3</sup>-registered Planning Coordinator (PC), while the PTOs are NERC-registered Transmission Planners (TP). In exercising this responsibility, CAISO may modify or identify new transmission reliability needs not identified in the individual TP plans that are submitted for this review.

<sup>2</sup> Starting in 2017, CAISO anticipates transitioning the activities formally involved in preparing the conceptual statewide plan into the interregional transmission coordination activities that it will conduct with WestConnect (and the other regional transmission planning entities in the Western interconnection, namely, Columbia Grid and Northern Tier Transmission Group).

<sup>3</sup> North American Electric Reliability Corporation; see <http://www.nerc.com/>.



**Figure A - 3. Overview of Phase II of the CAISO Transmission Planning Process**

Source: CAISO (2016b). *Business Practice Manual for the Transmission Planning Process*.

In evaluating whether identified reliability needs require transmission solutions, CAISO considers, among other factors, solutions suggested by stakeholders and staff. Notably, PTOs must submit solutions they seek to pursue as incumbent transmission owners. CAISO evaluates these solutions, along with solutions proposed by non-PTOs.

CAISO considers both transmission and non-transmission alternatives, such as demand response and generation. In addition, CAISO also considers transmission solutions that initially may or may not have been intended to address reliability needs, such as merchant transmission projects, as well as other forms of transmission projects (e.g., local transmission facilities to enhance resource deliverability).

The result of CAISO’s analysis is identification of reliability-driven transmission needs that require transmission solutions. If these solutions do not involve modifications to existing PTO transmission facilities, these solutions would require an open competitive process to select a developer.

CAISO next evaluates transmission needs that may be created by public policies. It begins by first determining the extent to which the transmission solutions previously identified to meet reliability needs could also satisfy public policy needs. This may involve recommending a modification to a previously identified solution, such as increasing its size (e.g., voltage class) or accelerating its development forward in time. CAISO parses these solutions to identify those that must be addressed in the current planning cycle versus those that should be considered in the next planning cycle. As with reliability-driven solutions, if the solutions identified for the current planning cycle are not upgrades to existing PTO transmission facilities, they would require an open competitive process to select a developer.

Finally, CAISO also conducts evaluations of transmission solutions to address the economic needs that emerge from the individual economic planning studies identified in Phase 1. Similar to the evaluation of public policy needs, the evaluations may involve modifications to previously identified transmission

solutions (such adjustments to their size or timing), or new transmission solutions. These evaluations are integrated with the evaluations of transmission needs created by public policies. As with both reliability-driven and public policy-driven solutions, if the economic-driven transmission solutions identified for the current planning cycle are not upgrades to existing PTO transmission facilities, they would require an open competitive process to select a developer.

CAISO conducts economic planning studies in two phases. In the first phase, CAISO identifies congestion within the power system/footprint by conducting hourly analysis for the tenth year in the future through production cost simulation, and for the fifth year as optional (which is needed for providing a data point in the benefit assessment for transmission project economic justification), highlighting and identifying the most congested/high-priority paths for further investigation. Congested lines, paths, or transmission interfaces are ranked based on the severity of the congestion, measured both in costs (\$billions) and as number of hours during which they are congested. CAISO also evaluates the economic study requests in this phase. The outcome of this phase is a list of up to five high-priority studies that will be studied and analyzed within the second phase of the economic study analysis. The final ranking can also include historically congested paths identified as high-priority paths, but for which no mitigation solution was found. In the second phase, the CAISO conducts detailed analyses for each of the high-priority studies individually, conducting a cost-benefit analysis using the TEAM methodology, based on the solutions that are proposed by stakeholders and transmission owners.

As noted, CAISO's economic evaluation is called TEAM; TEAM is based on security-constrained production cost simulations to assess the net present value of the benefits of transmission expansion. Notably, TEAM relies on a social discount rate (rather than a utility weighted-average cost of capital) to calculate the present value of future production cost benefits. To address uncertainty, CAISO conducts a structured set of sensitivity analysis each involving changing the assumed value of one key input (such as the future price of natural gas).

Phase 3 of CAISO's planning process involves conducting an open competitive process to select a project developer for a transmission solution that will receive regional cost allocation. As noted earlier, Phase 3 is only conducted if such solutions are approved by the CAISO board in its approval of the annual transmission plan.

### **Recent Transmission Planning Study**

This section summarizes information drawn from the 2015–2016 transmission planning cycle, focusing on the economic evaluation conducted by CAISO in the 2016 Economic Planning Study. The purpose of the study was to inform stakeholders about congestion within the CAISO footprint in 2020 and 2025, including options to mitigate it.

## Approach

The major elements of the CAISO economic study methodology have already been described. CAISO uses the ABB GridView production-cost simulation tool. The tool is used to simulate Western Electricity Coordinating Council (WECC) system operations, although the projects that are evaluated are generally sited within CAISO's footprint. The WECC production cost simulation model<sup>4</sup> is the starting database for all simulations. This model is reviewed and augmented using information specific to the CAISO footprint, including new/planned transmission upgrades, generating resources in the CPUC renewable portfolios, other non-renewable generating resources, and planned retirements and other information provided by each IOU.

## Findings

During the 2015-2016 Transmission Planning Process (TPP) cycle, CAISO carried out production cost simulations for the study years 2020 and 2025, ranking all congested transmission elements in the CAISO-controlled grid. Congestion results were first aggregated across specific branch groups and local capacity areas, and then ranked by severity in terms of congestion hours and congestion costs. CAISO selected five congested branch groups for the phase 2 evaluation:

- Path 26
- Exchequer
- POE-Rio OSO
- Path 15/Central California
- California-Oregon Intertie (COI)

In phase 2, CAISO evaluated stakeholder proposals for transmission (and non-transmission) solutions to address each congested path. CAISO found that none of the five branch groups merited an upgrade for several reasons. For Path 26 and Path 15/Central California, CAISO found that congestion costs had not changed significantly from previous planning cycles. For Exchequer and POE-Rio OSO, CAISO found that potential benefits of mitigating the congestion might depend heavily on the hydro modeling capabilities. For COI, CAISO found that marginal reductions achieved by the project did not produce sufficient benefits to warrant the project.

## Metrics

Congestion duration and cost are used to evaluate the severity of congestion. Benefit and revenue requirement (the total cost) and the benefit to cost ratio are used to evaluate the economic justification of a transmission project in economic planning. The metrics used by CAISO to evaluate the economic costs of congestion are described in Table A - 1.

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<sup>4</sup> This database is often called Transmission Expansion Planning Policy Committee (TEPPC). Changes to the database are reported in (CAISO 2015a).

**Table A - 1. CAISO’s Main Economic Metrics**

Metric	Description
<b>Congestion duration (# of hours)</b>	Represents the number of hours that an interface is at its limit and becomes a constraint
<b>Congestion cost (\$millions)</b>	Primarily used in CAISO economic studies to evaluate the severity of transmission constraints
<b>Benefit of a transmission upgrade (\$millions)</b>	Total benefit in net present value in proposed operation year, including energy benefit, capacity benefit, and other relevant benefits
<b>Total costs of a transmission upgrade (\$millions)</b>	Total revenue requirement in net present value in proposed operation year, including impacts of capital cost, tax expenses, operations and maintenance expenses, and other relevant costs

### Modeling and Selected Assumptions

**Load.** The CAISO production-cost simulation models 1-in-2 weather load in the TEPPC<sup>5</sup> database. California load is modeled using the CEC demand forecast. For the 2015–2016 TPP, California load comes from CEC 2013 IEPR<sup>6</sup> final demand-forecast data, published in 2012. Other areas of the WECC system are modeled using forecasted data from the WECC Load and Resource Subcommittee (LRS). Those data come from the utilities that participate in WECC. CAISO modified these load shapes based on the final LRS 2012 data. Each load area has an hourly load profile for the 8,760 hours in the production-cost simulation model. Individual bus load is calculated from the area load using a load distribution pattern that was imported from a power-flow base case. The GridView software supports modeling different load distribution patterns in the production cost model, for example, spring, summer, autumn and winter for a total of four load distribution patterns.

**Supply-side modeling.** CAISO replaced TEPPC’s California Renewable Portfolio Standard (RPS) modeling with the 2013–2014 CPUC/CEC Commercial Interest portfolio. This portfolio was created specifically to address the evolution of California’s RPS, updating the TEPPC RPS modeling suite which was not aligned with the latest CPUC/CEC RPS portfolio. The supply-side study also modeled two additional RPS portfolios as sensitivity cases. As in the 2013–2014 transmission plan, the “commercial interest (base)” portfolio was identified as the appropriate base case for CAISO to study in its 2014-2015 TPP because this portfolio represents the most likely future path of renewables development. The commercial interest portfolio heavily weights projects with an executed or approved power purchase agreement and a minimum “data adequacy” status for all major siting applications necessary for construction.

The CPUC and CEC also requested that CAISO study two sensitivity scenario portfolios in its 2014–2015 transmission planning process: (1) the “High Distributed Generation” portfolio and (2) the “Commercial Interest Sensitivity” portfolio, which considers an additional 1,500-megawatt capacity in the Imperial competitive renewable energy zone compared to what is considered in the commercial interest portfolio.

<sup>5</sup> WECC Transmission Expansion Planning Policy Committee; see <https://www.wecc.biz/TEPPC/Pages/Default.aspx>.

<sup>6</sup> 2013 Integrated Energy Policy Report; see [http://www.energy.ca.gov/2013\\_energy\\_policy/](http://www.energy.ca.gov/2013_energy_policy/).

Finally, in place of the Once-Through Cooling generation retirement and replacement assumptions in the TEPPC database, CAISO used more updated assumptions based on the latest CPUC's Long Term Procurement Plan (LTPP) processes and procurement forecasts.

**Transmission network representation.** For CAISO's TPP 2015 process, the entire WECC system is represented in a nodal network in the production-cost simulation database. Transmission limits are enforced on individual transmission lines, paths (i.e., flow-gates), and nomograms. The original TEPPC database only enforced transmission limits for 500kV, 345kV, and 230kV lines, but for the TPP 2015 study CAISO modified the database to enforce 500kV and 345kV transformer limits throughout the system. These modifications were made to ensure that transmission line flows stayed within their rated limits. In the updated database, CAISO modeled contingencies on the 500kV and 230kV lines in the California transmission grid to make sure that, in the event of losing one or more transmission facilities, the remaining facilities would stay within their emergency limits.

Economic planning studies start with a feasible system that meets reliability standards and policy requirements. To establish a feasible system, reliability-driven and policy-driven network upgrades are modeled in the base case. CAISO modeled some major network upgrades in the base case that were mostly above the 115kV level and were deemed to impact the power flows in the bulk transmission system. Network upgrades on-115kV and lower-voltage levels were assumed to be related to local problems with no significant impact on the bulk transmission system. Some approved network upgrades were not included in the TEPPC database.

**Regional modeling approach.** The TEPPC database includes hurdle rates for modeling frictions and aligning energy flows among the WECC balancing authorities. Representations of the energy imbalance markets between NV Energy and CAISO and between PacifiCorp and CAISO were added to the TEPPC database.

Table A - 2 lists selected modeling assumptions from the CPUC 2014 LTPP proceedings.<sup>7</sup> The simulations performed for CAISO's 2015-2016 TPP were based on 2020 and 2025 base cases.

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<sup>7</sup> The LTPP scenario tool was not rerun, and a link explicitly says that the 2014-2016 TPP specific information is available here (2014 IEPR Update CED forecast Form 1.5a-d): [http://www.energy.ca.gov/2014\\_energy\\_policy/documents/2014-12-08\\_workshop/lse/](http://www.energy.ca.gov/2014_energy_policy/documents/2014-12-08_workshop/lse/); the spreadsheet used is: [LSE and BA Tables Mid Demand Baseline-Mid AAEExlsx](#).

**Table A - 2. Selected Modeling Assumptions from CPUC 2014 LTPP Proceedings, Study Year 2020-2025**

Variable - Unit	Value	Source
Load – Summer Peak GW	51.1 GW- 51.1 GW	LSE and BA Tables, Mid Demand Baseline – Mid AAEE, 2014 IEPR Update, CED forecast, form-1.5a-d
Peak Demand Growth Rate	0.3%	LSE and BA Tables, Mid Demand Baseline – Mid AAEE, 2014 IEPR Update, CED forecast, form-1.1c
Net Annual Energy TWh	235,869–238,326	LSE and BA Tables, Mid Demand Baseline – Mid AAEE, 2014 IEPR Update, CED forecast, form-1.5a
<b>Natural gas prices</b>		
CO <sub>2</sub> price	\$23.27/m-ton price	Caveat: this is relative to the PLEXOS study and not the Economic Planning Study
SO <sub>x</sub> price		Not available
NO <sub>x</sub> price		Not available

### Acronym/Abbreviations

CAISO	California Independent System Operator
CEC	California Energy Commission
COI	California-Oregon Intertie
CPUC	California Public Utilities Commission
FERC	Federal Energy Regulatory Commission
IEPR	Integrated Energy Policy Report
IOU	Investor-owned utility
LRS	Load and Resource Subcommittee
LTPP	Long Term Procurement Plan
NERC	North American Electric Reliability Corporation
PC	Planning Coordinator
PTO	Participating Transmission Owner
RPS	Renewable Portfolio Standard
TEAM	Transmission Economic Assessment Methodology
TEPPC	Transmission Expansion Planning Policy Committee
TP	Transmission Planner
TPP	Transmission Planning Process
WECC	Western Electricity Coordinating Council

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## Appendix B. ColumbiaGrid

### Summary

ColumbiaGrid is an association of transmission owners serving portions of the Pacific Northwestern states of Idaho and Washington. ColumbiaGrid's principal activity is to conduct regional transmission planning activities in compliance with Federal Energy Regulatory Commission (FERC) Order Nos. 890 and 1000 that, among other things, may lead to the selection of transmission projects for regional cost allocation. The economic evaluation of transmission projects includes application of production cost models to estimate regional economic benefits.

### Background

ColumbiaGrid was formed in 2006. It is comprised of both publicly owned and investor-owned utilities, and the Bonneville Power Administration.<sup>8</sup> ColumbiaGrid's principal transmission planning activity is the preparation of a region-wide assessment of (and expansion plan for) the transmission systems spanning the footprints of its members.<sup>9</sup>

FERC Order No. 1000 led ColumbiaGrid to enhance its planning process to include: (1) opportunities for stakeholders to recommend regional needs for transmission (including transmission needs driven by public policy requirements) that ColumbiaGrid evaluates and on which it must make a finding confirming that there is an Order No. 1000 regional need; and, if confirmed, (2) opportunities for stakeholders and potential developers to study and propose (and, as in the past, ColumbiaGrid staff to evaluate independently) transmission (and non-transmission) solutions to meet these regional needs.

ColumbiaGrid relies on a sponsorship model to select project developers. This means that transmission solutions proposed by those other than would-be developers and which are found to be more efficient or cost-effective, must subsequently become sponsored by a developer. And this sponsorship may trigger re-evaluation of the initial regional cost allocation established for the solution. ColumbiaGrid's Order No. 1000-compliant regional transmission planning process and cost allocation provisions became effective for the region in January, 2015.

Participant funding approaches have been used to allocate costs to various parties prior to and after ColumbiaGrid's formation. However, ColumbiaGrid has not selected any transmission projects for regional cost allocation subsequent to the effective dates for regional transmission planning following the requirements of Order No. 1000.

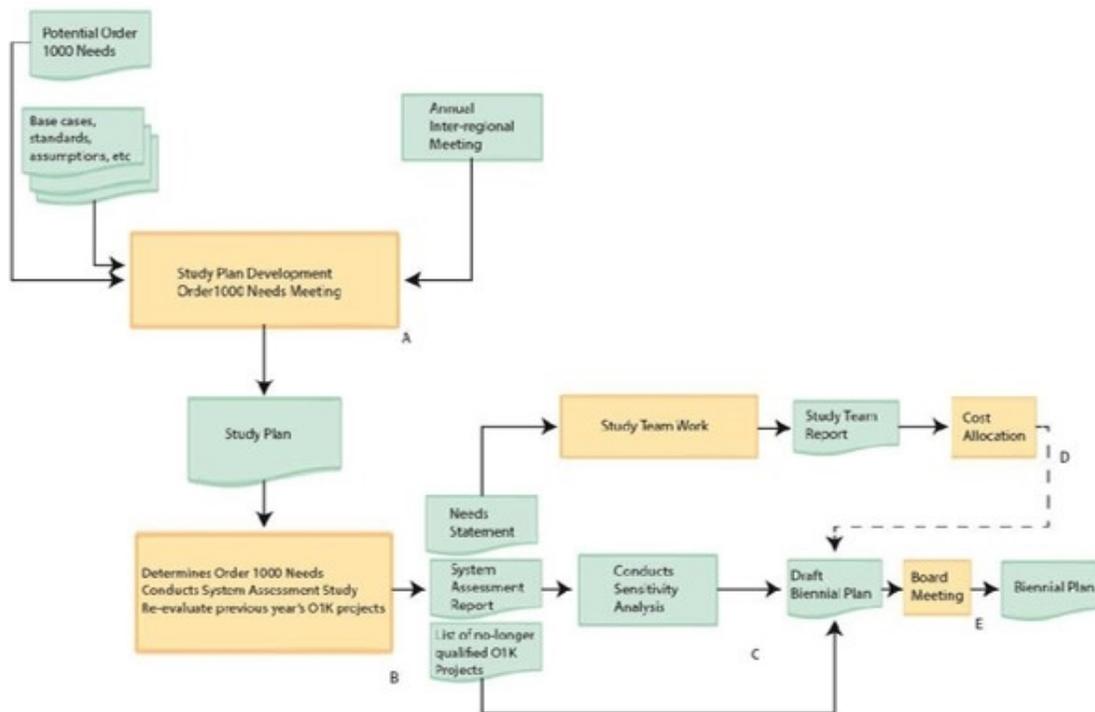
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<sup>8</sup> It is important to note that many ColumbiaGrid participants are not subject to FERC jurisdiction and hence not subject to the regional transmission planning requirements of Order Nos. 890 and 1000.

<sup>9</sup> ColumbiaGrid's interregional transmission coordination activities are not the focus of this report and are not discussed in this summary.

## Regional Transmission Planning

ColumbiaGrid’s principal planning activities involve, first, preparation of a system assessment on an annual basis and, second, preparation of a transmission expansion plan on a biennial basis.<sup>10</sup> See Figure B - 1. The purpose of both of these activities is to evaluate and plan for the needs of the combined systems of the participating utilities on an integrated basis (i.e., viewed as a single entity). The scope of the activities is to look ahead over five- and ten-year planning horizons.



**Figure B - 1. Overview of ColumbiaGrid’s Planning Process**

Source: ColumbiaGrid (2016). 2016 Update to the 2015 Biennial Plan.

ColumbiaGrid’s annual system assessment focuses on the following activities: (1) reliability assessment of the integrated transmission systems to identify North American Electric Reliability Corporation (NERC) or Western Electricity Coordinating Council (WECC) planning criteria violations that affect more than one participant’s system; (2) evaluation of transmission needs identified in FERC Order No. 1000 (i.e., transmission needs driven by public policy requirements) based on recommendations made by stakeholders, which are then evaluated by ColumbiaGrid; (3) re-evaluation of projects selected for regional cost allocation in the most recent prior expansion plan; and (4) preparation of other technical studies based on the direction from planning parties. These later studies are called sensitivity studies; their scopes are defined each year.

<sup>10</sup> ColumbiaGrid has the option to prepare an update to its most recent Biennial Transmission Expansion Plan following completion of the annual system assessment that is conducted between the preparations of the biennial transmission expansion plan.

ColumbiaGrid’s biennial transmission expansion plan reports on all study activities that have been conducted pursuant to the release of the annual system assessments. These include activities to address findings from the most recent reliability assessment, as well as the results of economic planning, and other studies (i.e., the sensitivity studies). The principal outcome of the biennial transmission expansion plan is an updated list of the projects that the participants commit to build over the next ten years.

ColumbiaGrid has conducted economic planning studies since 2013. The studies rely on production cost modeling tools that simulate the hourly dispatch of generation. The studies generally have two phases: (1) backcast (benchmark); and (2) forecast (future).

Benchmarking is accomplished by comparing simulation results with historical data to see how well the model outcomes mimic historical operating data for the same time frame. When benchmark studies have shown significant diversion between the two sets of data, adjustment to the starting dataset were made, to improve the alignment of simulation results and historical operations data. Examples of such changes are natural gas prices, transmission projects planned for operation, and renewable energy profiles.

ColumbiaGrid then uses the calibrated tools to examine how generation dispatch and power flow pattern might change in the future under different assumptions, such as changes in the quantity and mix of generation. ColumbiaGrid’s analysis focuses on how the utilization of integrated transmission systems might be affected, such as changes in patterns of flows over key interfaces. ColumbiaGrid’s analysis also includes an estimation of production cost impacts, however, these impacts are not the main focus of ColumbiaGrid’s study.

Since the implementation of ColumbiaGrid’s economic planning studies, the results have not yet triggered a transmission project update or benefit-cost analysis, but they are to be used in conjunction with other ColumbiaGrid technical studies to help ensure grid reliability and efficiency.

## **Recent Transmission Planning Study**

This section summarizes information drawn from ColumbiaGrid’s 2016 transmission planning activities.

### **Approach**

ColumbiaGrid conducted the economic planning study using the WECC 2026 base case (production-cost model) developed by the Transmission Expansion Planning Policy Committee (TEPPC). ColumbiaGrid’s study focused on two analysis topics:

1. Coal retirement in the Northwest and its impact on Northwest generation and transmission facilities
2. Impact of updated assumptions for 2017 and hydroelectric modeling with a focus on the Northwest

## Findings

ColumbiaGrid first performed a backcast study comparing historical system behavior with initial production-cost simulation results. In general, among many model improvements that were applied to the starting dataset, the following key modeling changes were made for both studies listed above:

1. Natural gas prices were adjusted to reflect natural gas trading hub prices and local transportation fees
2. For non-dispatchable supply, renewables such as wind and solar were dispatched based on historical solar and wind patterns

Overall, ColumbiaGrid’s production-cost modeling simulations that were carried out using the updated models showed few changes in power flow on the major WECC paths in the region under study (i.e., west of Cascades, north of John Day, the Pacific DC Intertie (PDCI) and California-Oregon Intertie (COI) and Northwest to British Columbia). Other results show generation switching between coal and natural gas because of the concurrent 57% increase in coal prices and a reduction in natural gas prices.

## Metrics

ColumbiaGrid used the changes in power flow on major interfaces in the WECC database as a metric to estimate any change in the simulation results after pursuing modeling changes to the database.

## Acronyms and Abbreviations

COI	California-Oregon Intertie
FERC	Federal Energy Regulatory Commission
NERC	North American Electric Reliability Corporation
PDCI	Pacific DC Intertie
TEPPC	Transmission Expansion Planning Policy Committee
WECC	Western Electricity Coordinating Council

## References

ColumbiaGrid (2016). *2016 Update to the 2015 Biennial Plan*. February 2016.  
<https://www.columbiagrid.org/client/pdfs/2016BiennialPlan-Finalweb.pdf>.

## Appendix C. Florida Reliability Coordinating Council (FRCC)

### Summary

The Florida Reliability Coordinating Council (FRCC) is a North American Electric Reliability Corporation (NERC)<sup>11</sup> regional reliability entity for peninsular Florida (east of the Apalachicola River). Following Federal Energy Regulatory Commission (FERC) Order No. 1000, FRCC's member services division began conducting additional planning activities that satisfy Order No. 1000 requirements for the affected member utilities. The evaluation of transmission projects that might be selected for regional cost allocation includes comparing the expected cost of a qualified sponsor-proposed project to that of project(s) from the regional transmission plan that it would (or could) displace, along with any reductions in transmission losses.

### Background

FRCC's predecessor, Florida Electric Power Coordinating Group, was formed in 1972, and became known as FRCC in 1996. At that time, FRCC petitioned to transition from a sub-region of the Southeast Electric Reliability Council (SERC) to become its own NERC regional reliability organization. Today, FRCC is one of NERC's eight Regional Entities with delegated authority under the Federal Electric Reliability Organization (ERO) construct. However, FRCC also maintains a member services division which has activities outside its ERO delegated functions. FRCC also serves as the registered Reliability Coordinator for the FRCC transmission systems and as a registered Planning Authority (PA) with a coordinated functional registration with the FRCC's transmission planners and other PAs. In 2015, FRCC, under its member services division, also became one of the 12 FERC-recognized transmission planning regions, including three of the state's investor-owned utilities (IOUs), along with the cooperatives and municipal utilities.

FRCC's regional transmission planning responsibilities in support of FERC Order Nos. 890 and 1000 were incorporated into its existing coordinated reliability planning among the transmission entities within its footprint. FRCC's Order No. 1000-compliant regional transmission planning process and cost allocation provisions became effective for the region in January 2015.

There is no prior history of regional cost allocation for transmission projects within FRCC. To date, following the planning processes directed by Order No. 1000, no transmission projects have been selected for regional cost allocation.

### Regional Transmission Planning

FRCC conducts two overlapping regional transmission planning activities.<sup>12</sup> The first is called the annual transmission planning process. The second is called the biennial transmission planning process.

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<sup>11</sup> North American Electric Reliability Corporation; see <http://www.nerc.com/>.

<sup>12</sup> FRCC's interregional transmission coordination activities with SERTP (Southeastern Regional Transmission Planning) are not the focus of this report and are not discussed in this summary.

The annual transmission planning process conducts an integrated region-wide review of the local transmission plans of the transmission entities within FRCC. The principal focus of the review is to ensure compliance with NERC reliability planning standards and FRCC planning criteria, and to document a regional and coordinated transmission plan. The regional plan that emerges from the annual process becomes the starting point for the biennial transmission planning process. The annual regional plan contains critical energy infrastructure information and is made available for public review only when appropriate protections have been put in place.

The biennial transmission planning process, which is started in each odd-numbered year, is the process by which FRCC evaluates regional transmission alternatives or solutions that might be selected for regional cost allocation. The evaluation determines whether a proposed alternative is a more cost-effective or efficient transmission solution than a project (or projects) contained in the regional plan that emerges from the annual transmission planning process. The biennial transmission process is also the means by which FRCC evaluates transmission needs driven by public policy requirements.

The evaluation of a proposed regional transmission alternative involves both a reliability and an economic analysis. The reliability analysis must confirm that a proposed alternative will meet NERC and FRCC reliability planning criteria at least as well as the project(s) from the regional plan that it might displace. The evaluation then compares the expected cost of an alternative to the project(s) from the regional plan that would be displaced, as well as considers the reduction of transmission losses on the beneficiaries' transmission systems due to the proposed alternative.

FRCC's biennial transmission planning process can be thought of as a sponsorship model. That is, any stakeholder (incumbent or non-incumbent) may sponsor a regional transmission alternative and an evaluation will be made to determine if their alternative is more cost-effective or efficient solution. Then, if the project sponsor is a qualified project developer, they would be selected to develop the project (and receive regional cost allocation for it). In this regard, while stakeholders can propose regional transmission alternatives for consideration, the FRCC biennial process is organized principally to vet proposals from qualified, developers (non-incumbents and incumbents).

FRCC's assessment of transmission needs driven by public policy requirements involves soliciting proposals from stakeholders. FRCC evaluates these proposals and determines whether the needs they describe are based on public policy requirements. FRCC, as part of the biennial process, will conduct an open competitive process to identify regional transmission solutions, including projects sponsored by qualified developers. If selected, these projects would receive regional cost allocation.

The FRCC biennial transmission planning process need not lead to preparation of a standalone transmission project. As noted, no regional projects have emerged from the process thus far.

## Acronyms and Abbreviations

ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
IOU	investor-owned utilities
NERC	North American Electric Reliability Corporation
SERC	Southeast Electric Reliability Council

## References

- Florida Reliability Coordinating Council (FRCC) (2016). *2016 Regional Load & Resource Plan, FRCC-MS-PL-079, Version: 1*. May 2016. <https://www.frcc.com/Planning/Shared%20Documents/Load%20and%20Resource%20Plans/FRCC%202016%20Load%20and%20Resource%20Plan.pdf>.
- FRCC (2015). *FRCC Regional Transmission Planning Process, FRCC-MS-PL-018 Version: 3*. October 30, 2015. [https://www.frcc.com/Planning/Shared%20Documents/Regional%20Transmission%20Planning%20Process/FRCC-MS-PL-018\\_FRCC\\_Regional\\_Transmission\\_Planning\\_Process.pdf](https://www.frcc.com/Planning/Shared%20Documents/Regional%20Transmission%20Planning%20Process/FRCC-MS-PL-018_FRCC_Regional_Transmission_Planning_Process.pdf).

## Appendix D. ISO New England (ISO-NE)

### Summary

ISO New England (ISO-NE) operates the high-voltage power system, administers a centralized market for wholesale power, and conducts power system planning for the six Northeastern states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. ISO-NE conducts transmission planning studies that, among other things, lead to the identification of reliability and market efficiency transmission upgrades, and public policy upgrades. ISO-NE also administers the interconnection process for elective transmission upgrades and new generation projects. Economic planning studies—which can demonstrate the need for market efficiency upgrades and inform stakeholders and public policy officials on investment decisions—consider the impact of projects on economic congestion costs, overall system production costs and other relevant cost metrics as well as non-cost metrics such as emissions. The economic planning studies are conducted in response to stakeholder requests.

### Background

ISO-NE is the regional transmission organization (RTO) for the New England region. It can be thought of as a descendent of the original power pooling arrangements that formed nearly 50 years ago to foster regional coordination on power system operations, including planning, among the utilities serving the six New England states. ISO-NE was formally established in 1997 in response to the passage of the Energy Policy Act of 1992, which removed barriers to competition in the wholesale generation of the electricity business.

ISO-NE has been conducting regional transmission system planning studies since its inception. These activities closely followed the region’s transition over the course of the 1990s away from pancaked rates for transmission to regional postage stamp rates. The transition culminated with the establishment of formal rules for regional cost-allocation for transmission projects 115kV and above following Federal Energy Regulatory Commission (FERC) Order No. 2000.

FERC Order No. 890 did not lead to major changes to ISO-NE’s planning practices save for the formalization of some processes—such as those guiding ISO-NE economic studies of up-to three stakeholder-identified areas of interest per year.

FERC Order No. 1000 resulted in two major changes to ISO-NE’s planning processes. First, ISO-NE now provides for a “sponsorship” process to select transmission projects to address identified needs (which are eligible for regional cost allocation) in which regional reliability transmission needs that are more than three years into the future may be met by incumbent or non-incumbent transmission developers identified through an open competitive process. Second, in early 2017 ISO-NE initiated its first process to identify transmission needs required to meet public policies.

A third major component of FERC Order No. 1000, interregional transmission coordination, has not resulted in major changes for ISO-NE because it has been participating, in a manner that was already largely compliant with the new Order No. 1000 requirements, in interregional transmission coordination activities with New York ISO (NYISO) and PJM Interconnection (PJM) since 2004.<sup>13</sup> ISO-NE's Order No. 1000-compliant regional transmission planning process and cost allocation provisions became effective for the region in May 2015.

## **Regional Transmission Planning**

The results of ISO-NE's transmission planning processes are required to be summarized no less than once every three years in its Regional System Plan (RSP). ISO-NE's current practice is to issue the RSP every two years, with a ten-year planning horizon. In addition to the identification of transmission projects, the RSP reports on a number of related study activities (such as the development of a regional forecast of energy and demand) and topical studies (such as integration of variable energy resources). The principal types of transmission projects included in the RSP are reliability upgrades; market efficiency transmission upgrades; public policy upgrades; elective transmission upgrades; and generation interconnection-related upgrade projects. The focus of this discussion is on the processes used to identify the first four of these project types. See Figure D - 1 through Figure D - 5.

ISO-NE planning for reliability transmission projects follows planning standards promulgated by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC), as well as internal standards developed by ISO-NE. ISO-NE is, in fact, the NERC-registered Planning Coordinator (PC) and Transmission Planner (TP) for 98% of the transmission facilities within the region. If a reliability-driven transmission need 115kV and above<sup>14</sup> must be met in three years or less, then ISO-NE works with the incumbent transmission owner to develop the more efficient or cost-effective solution to address the identified needs. The costs of these projects are eligible to be allocated regionally. If an identified regional transmission need does not need to be met in less than three years, ISO-NE conducts a two-phase competitive solution process to select a project from either an incumbent or non-incumbent Qualified Transmission Project Sponsors (QTPS), and this project would be eligible for regional cost allocation.

It is useful to first describe the annual economic study process ISO-NE employs. Studies may be driven by either persistent, high economic congestion costs, or by a desire to access (or increase access to) a remote future generation source (e.g., wind). Importantly, the assumptions relied on by ISO-NE to conduct these studies are established through the stakeholder process. The principal evaluation metric produced by the studies is avoided system production costs compared to the expected cost of a transmission solution.

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<sup>13</sup> ISO-NE's interregional transmission coordination activities are not the focus of this report and are not discussed in this summary.

<sup>14</sup> Existing 69kV facilities are also subject to a similar process, but the costs associated with new 69kV facilities are not eligible for regional cost allocation.

In addition, ISO-NE annually conducts up to three stakeholder-identified economic studies of the ISO-NE control area that may include multiple scenarios for ISO-NE to evaluate. ISO-NE conducts economic planning studies to inform both stakeholders and policy makers about the potential value and cost of meeting these stakeholder-proposed scenarios for resource and transmission expansion. That is, the studies, by themselves, do not constitute a finding of need by ISO-NE. If, however, ISO-NE determines that a study's findings appear to warrant a transmission solution, it will re-run the analysis using its own assumptions (which may or may not differ from those developed by the stakeholders). If ISO-NE's re-analysis confirms the earlier finding, it may then initiate a two-phase competitive process to select a QTPS to meet the identified need.<sup>15</sup> If selected, the QTPS's project is designated as a 'market efficiency transmission upgrade' (METU) and is eligible to receive regional cost-allocation. Economic Study requests have also included non-economic metrics, where those submitting the request have asked ISO-NE to look at impacts to emissions from various different scenarios. Such requests can not only inform economic planning, but can also inform public policy decisions by policy makers.

Regardless of whether ISO-NE conducts an economic study, incumbent and non-incumbent transmission developers always have the ability to propose and develop transmission projects that will not seek regional cost allocation. These types of transmission projects can be considered participant funded, and are referred to as 'elective transmission upgrades' (ETU). The significance of this designation from a regional perspective is that the costs associated with ETU projects are not eligible for regional cost allocation. For example, if such a project addresses the transmission need previously identified in an economic planning study, then there is no need for ISO-NE to conduct a competitive process to select a market efficiency transmission upgrade project for regional cost allocation; the need has already been met.

ISO-NE's transmission planning process for public policy projects relies heavily on a determination by the New England State Committee on Electricity (NESCOE),<sup>16</sup> of public policies appropriate for consideration. ISO-NE confirms that these transmission needs are required and then assesses whether these needs are (or are not) already being met by existing or planned reliability, market efficiency transmission upgrades, or elective transmission upgrade projects, or if there are more efficient or cost-effective alternatives presented. If un-met needs are identified, ISO-NE will conduct a two-phase competitive process to select a project sponsor, whose project would be eligible to receive regional cost allocation.

As indicated, ISO-NE initiated its first round of the planning processes to identify transmission needs required to meet public policies in early 2017.

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<sup>15</sup> Unlike reliability projects that must address needs three years or less into the future, all market efficiency transmission upgrades must be selected through a competitive process in order to receive regional cost allocation.

<sup>16</sup> NESCOE is a FERC-recognized Regional State Committee comprised of representatives designated by each of New England states' governors.

## Recent Economic Planning Study

This section summarizes information drawn from a recent ISO-NE economic planning study focusing on the economic evaluation conducted by ISO-NE. As part of the 2015 RSP (ISO-NE 2015a), ISO-NE conducted three planning studies requested by stakeholders:

1. Keene Road Interface Economic Study Request (Sun Edison)
2. Economic Study Proposal to Evaluate the Impact of Offshore Wind Deployment on New England's Wholesale Electricity Markets and Operations (Massachusetts Clean Energy Center)
3. Economic Study Proposal: Economic Impact of Maine Upgrades Identified in ISO New England's Strategic Transmission Analysis for Wind Integration (RENEW Northeast, Inc. (RENEW))

### Approach

ISO-NE's economic planning studies consider future trajectories (e.g., wind-expansion levels, transmission limit increases), from a shared base case and include sensitivities for key parameters used (e.g., fuel prices, generation retirements, etc.). ISO-NE used the ABB GridView production cost modeling tool to conduct the economic planning studies.

### Findings

The Keene Road economic study (ISO-NE 2016b) involved increasing a network interface from 165 MW to 225 MW in order to accommodate increased transmission for generation from wind within a specific locality in the state of Maine. Considering existing wind resources in the region, the production cost benefits were found to be about \$1.6 million/year which would allow for a capital investment cost of \$10.1–\$11.6 million. If additional wind generation totaling 53 MW (based on projects in the interconnection queue behind the interface as of April 1, 2015) were developed in the exporting region, the production cost benefits increase to \$5.2 million/year, which would allow for a capital investment of \$32.4–\$37.0 million.

The study of offshore wind in southern New England suggests that deployment of these resources could bring sizable economic and environmental benefits to New England. The estimated economic benefits, based mainly on production cost savings and load-serving entity (LSE) energy expense savings, almost double when offshore wind expansion levels are increased from 1,000 MW to 2,000 MW. Because energy produced by offshore wind offsets energy generated by emission-producing thermal units, the addition of offshore wind also decreases network flow and congestion on two major interfaces on the ISO-NE controlled grid, i.e. North–South and SEMA/RI import interfaces (in addition to reducing emissions in the region).

ISO-NE also examined increasing transmission interface limits from another portion of the Maine region of the system, again to accommodate increased wind generation. If there is less than 1,149 MW of wind in Maine, with 334 MW located north of Orrington South, production cost savings are less than \$5 million annually. If there is more than 2,084 MW of wind in Maine, with more than 1,185 MW located

north of Orrington South, the annual savings increase to \$38–\$75 million. Further increasing imports from New Brunswick increases the annual production cost savings to \$78 million.

The study carried out on the Keene Road area in Maine helped ISO-NE identify a variety of benefits resulting from expanding/increasing transmission interfaces in the specific area of the power grid, and, as a result, ISO-NE reviewed the potential for an METU. The METU study (ISO-NE 2017) reflected input from the Planning Advisory Committee and showed that production cost savings of under \$1.4M per year for increasing the Keene Road interface from 165 MW to 195 MW. Further increases in the transfer limit up to 225 MW resulting in additional savings of \$0.1M to \$0.18M per year. It was concluded that an METU could not be justified.

### Metrics Used in the 2015 Economic Planning Study

The key economic metrics used to compare all simulation runs to one another are (a) production costs; and (b) LSE energy expenses; these are computed using GridView. These metrics do not consider absolute values because the aim was to quantify changes relative to the base case. Table D - 1 describes the simulation metrics used in the economic studies.

**Table D - 1. Main Economic Metrics**

Metric	Description	Notes
<b>Bottled-in Energy (gigawatt-hours [GWh])</b>	Represents the amount of energy that cannot be produced and exported because of transmission constraints	ISO-NE uses this metric to quantify the amount of wind and hydro energy that is curtailed in the model because of multiple possible conditions, (i.e., the threshold price at which energy is self-curtailed, lack of sufficient transmission infrastructure). This metric also accounts for the amount of bottled-in energy that cannot be imported to/exported from the region under study
<b>Interface Constrained Hours (% of Hours at Limit)</b>	Represents the number of hours that an interface is at its limit and becomes a constraint	ISO-NE uses this metric to gain insight into transmission system capabilities and limitations and potential transmission projects evaluated in a study may reduce the number of constrained hours
<b>Production Costs (\$Millions)</b>	Primary metric to evaluate potential changes to transmission system and addition of new types of resources (not limited only to transmission projects)	This metric is based on the summation of dispatch costs for each unit multiplied by the amount of energy produced and is computed by aggregating all NE resources that serve customer demands. While this is a NE-wide metric, not a sub-regional metric, NE-wide production costs will decrease if more economic energy can be delivered from a previously constrained sub-area. While the production costs for resources located in areas external to the ISO-NE footprint do not affect the production cost metric, the amount of transfers with neighboring systems does not affect the metric

Metric	Description	Notes
<b>Implied Range of Capital Investment Attributable to Production-Cost Savings (\$Millions)</b>	Represents an estimated range of capital investments that can be justified using NE-wide production cost savings as the offset to the transmission project so that New England customers are, at a minimum, indifferent to either the higher production costs or the transmission costs	Annual carrying charges are typically assumed to be 14%-16% of capital costs of new transmission development. ISO-NE uses the production costs savings computed by GridView
<b>Load-Serving Entity Energy Expense (\$Millions)</b>	Reflects the total amount that consumers of wholesale electric energy (utilities and competitive power marketers) would spend to procure energy valued at the spot LMP	LSE electric energy expense is calculated by taking the hourly marginal energy cost (e.g., the locational marginal price) in an area and multiplying it by the hourly load within that same area
<b>System CO<sub>2</sub> Emissions (kilotons)</b>	Reflects total ISO-NE emissions generated only by thermal units within New England	Energy imported from external areas is assumed to be emissions free

### Modeling and Selected Assumptions in the 2015 Economic Planning Study

ISO-NE develops an annual, centralized ten-year forecast of capacity, energy, loads, and transmission (CELT). This forecast is used in power system planning and reliability studies<sup>17</sup> (ISO-NE 2015b) and contains detailed ISO-NE Reliability Coordinator (RC)-area forecasts. The forecast is compiled using data provided by market participants and from internal ISO-NE forecasts. The CELT Report is published on May 1 of each year, and economic studies undertaken after that date use the updated version of the report. Table D - 2 presents a selection of key assumptions used in each year's economic studies.

**Load.** The ten-year forecast of the ISO-NE RC area energy and seasonal peak demand is based on econometric models of energy and seasonal peaks for the ISO-NE RC area and the six New England states. Transmission owners develop distribution factors for a ten-year forecast period to allocate loads to the buses across the New England network. A forecast is also provided of the reductions from the Gross Loads as a result of passive demand resources, which are treated as resources in installed capacity requirement calculations. The ten-year forecast for New England does not include the load forecast for Northern Maine (provided by the Maine Public Service Company), as this area is served from New Brunswick. The load data used in the economic studies include the energy associated with PDR (energy efficiency), which is modeled as a resource. Photovoltaic energy resources and active demand-response<sup>18</sup> resources are used as supply, but behind-the-meter PV is also subtracted from the gross demand. The hourly load profile is based on 2006 weather data and synchronized with wind and photovoltaic profiles.

<sup>17</sup> See <http://www.iso-ne.com/system-planning/system-plans-studies/celt>.

<sup>18</sup> Active demand-response resources actively participate to the wholesale market, contrary to event-based resources that are triggered only by specific conditions.

**Energy efficiency.** The Energy-Efficiency Forecast Working Group (EEFWG) provides an annual energy-efficiency forecast based on input from several experts, including state agencies, energy-efficiency program administrators, NESCOE, and other stakeholders. EEFWG verifies performance data on energy-efficiency programs in New England. The detailed energy-efficiency forecast methodology is reported in ISO-NE (2016e).

**Supply-side modeling.** Generation retirements and new units are modeled based on Forward Capacity Auction #9 resources. Hydroelectric resources in New England have monthly energy profiles based on historical generation; this monthly electric energy is then converted to an hourly profile based on the assumption that some amount of hydroelectricity would be produced in every hour—although hydroelectric generation would tend to be greater when loads are highest and less when loads are lower. ISO-NE used this methodology for economic studies in all areas of New England. Hourly wind profiles are based on data produced by the National Renewable Energy Laboratory (NREL) and updated in 2012 to reflect improvements in turbine efficiencies.<sup>19</sup> The profile assignment for each individual resource was based on the nearest NREL data site.

**Transmission system network representation.** The detailed ISO-NE transmission network used in the economic planning studies is based on a 2021 summer steady-state base case from the ISO's NERC TPL-001-4 Compliance Study.<sup>20</sup> The case reflects transmission improvements listed in the RSP Project List as of May 18, 2015, including the Maine Power Reliability Program,<sup>21</sup> and additional updates through June 1, 2015. Some import/export interchange flows among the regions under study may change as part of sensitivity analysis (ISO-NE 2016c). Major transmission interface limits between load and generation areas are modeled consistent with transmission improvements expected to be in service by 2021. Based on the topic being studied, some local transmission constraints may be examined, for example, the SEMA/RI import interface (ISO-NE 2016c).

**Environmental emissions allowances.** Thermal unit emissions are estimated based on the energy generated by each unit and its associated emission rates. Emission rates were developed in support of the 2014 ISO New England Electric Generator Air Emissions Report (ISO-NE 2016a). The energy imported from New Brunswick, New York, and Québec was assumed to have zero emissions accruing to New England.

**Regional modeling.** Interchange with neighboring areas is represented by a fixed interchange schedule with a zero cost for imports and zero revenues for exports. Because of this particular assumption, production costs for resources located in external areas are assumed constant among cases, but can be reduced in the case of congestion.

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<sup>19</sup> National Renewable Energy Laboratory (NREL). "Transmission Grid Integration," webpage (May 6, 2015), [http://www.nrel.gov/electricity/transmission/eastern\\_wind\\_methodology.html](http://www.nrel.gov/electricity/transmission/eastern_wind_methodology.html).

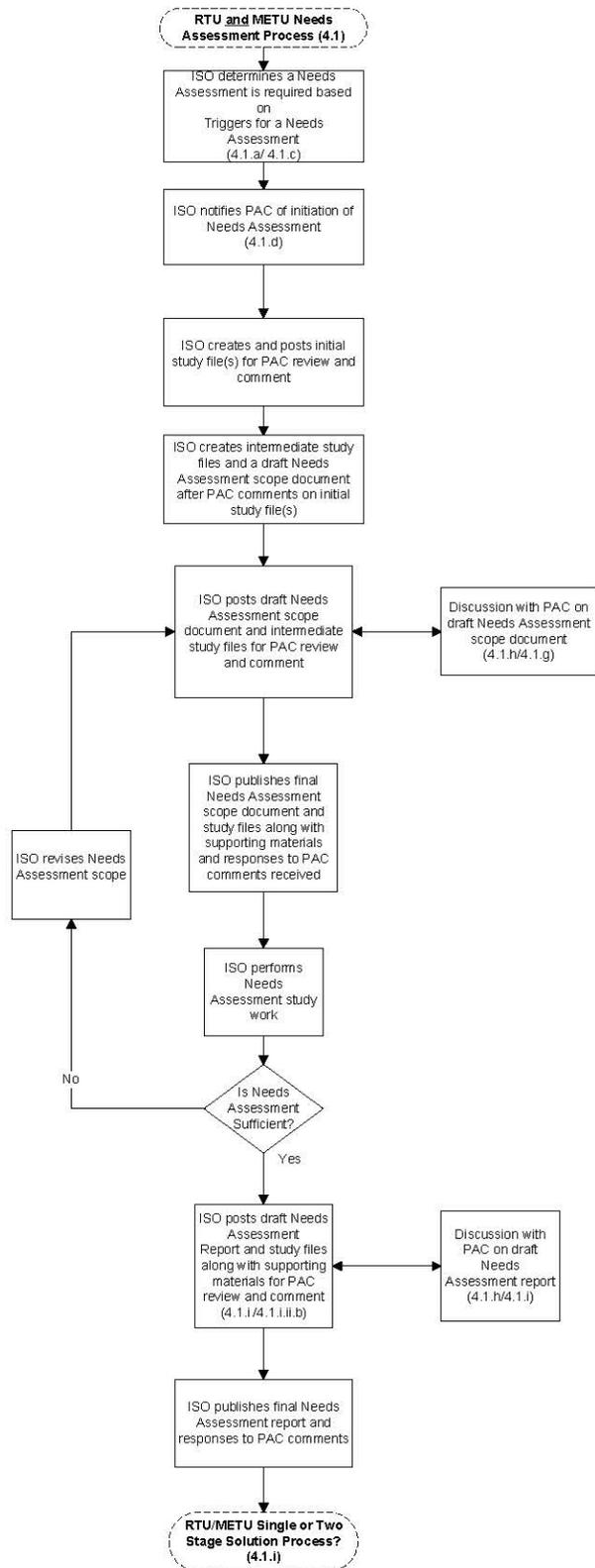
<sup>20</sup> ISO-NE. "Summary of Steady-State Base Cases for TPL-001-4 Studies," [http://www.iso-ne.com/static-assets/documents/2015/07/final\\_summary\\_of\\_steady\\_state\\_basecases\\_for\\_tpl\\_001\\_4.pdf](http://www.iso-ne.com/static-assets/documents/2015/07/final_summary_of_steady_state_basecases_for_tpl_001_4.pdf).

<sup>21</sup> The RSP15 is a list of transmission reliability projects that have been approved by the ISO's Board during past planning processes, and are at different stages of implementation. The Final *RSP15 Project List* (May 2015) is available at <http://www.iso-ne.com/system-planning/system-plans-studies/rsp/>.

Table D - 2 reports selected modeling assumptions used in the economic studies.

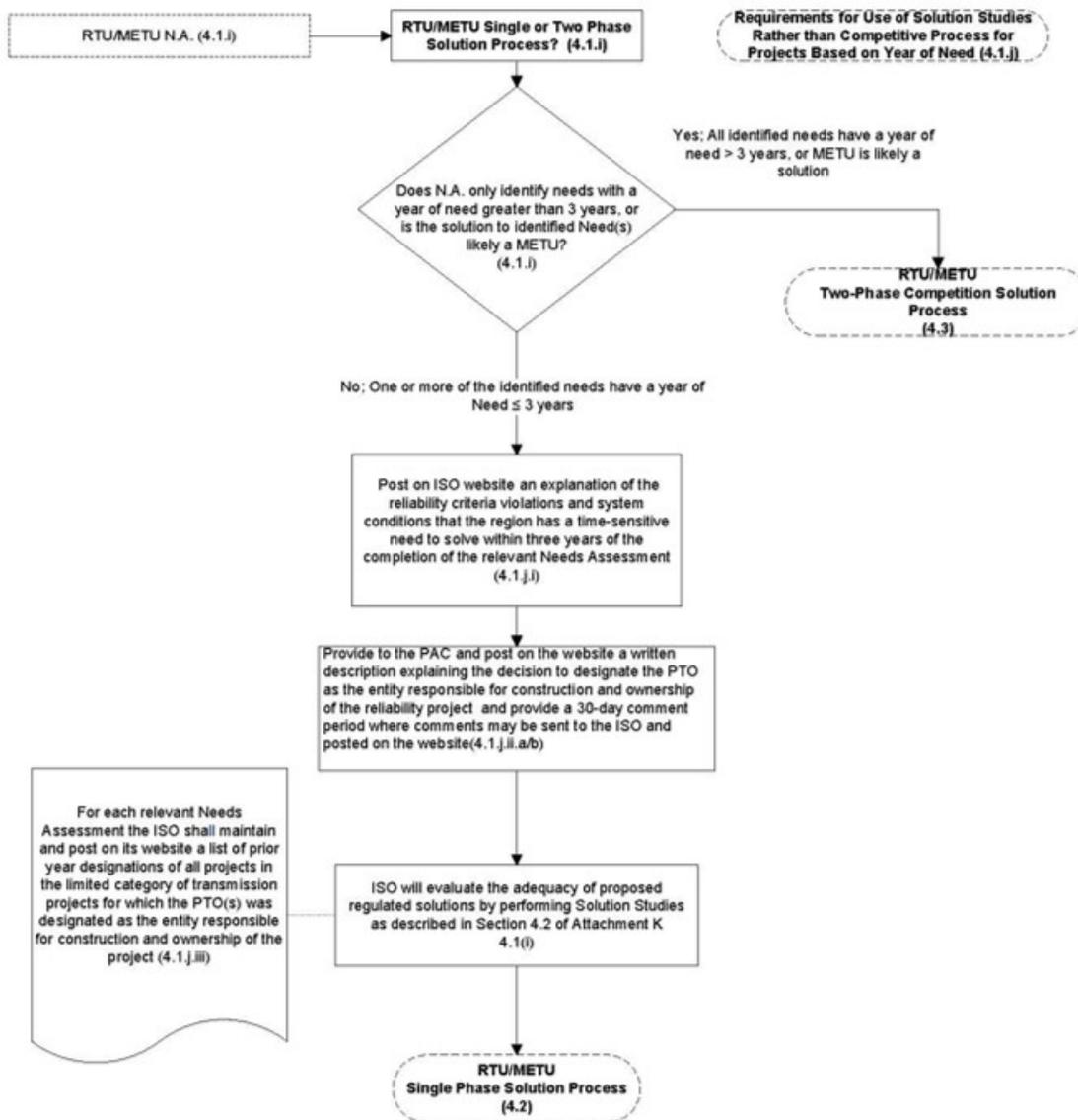
**Table D - 2. Selected Modeling Assumptions, Study Year 2021**

<b>Variable – Unit</b>	<b>Value</b>	<b>Source</b>
<b>Load – Summer Peak GW (July 2021)</b>	30.9 – (1.4%/year from 2015)	2015 CELT Report
<b>Load – Winter Peak GW (Jan. 2021)</b>	23.7 – (0.7%/year from 2015)	2015 CELT Report
<b>Natural gas prices 2013 \$/MMBTU (2021)</b>	Monthly values adjusted by season ( <i>Winter/Jan: 1.09, Summer/Aug: 0.95</i> )	EIA 2015 Annual Energy Outlook
<b>Coal prices 2013 \$/MMBTU</b>	One value for entire year	EIA 2015 Annual Energy Outlook
<b>CO<sub>2</sub> price</b>	\$20/short ton	2014 ISO-NE
<b>Sulfur oxide price</b>	\$6/short ton	Electric Generator Air Emissions Report
<b>Nitrogen oxides price</b>	\$5/short ton	



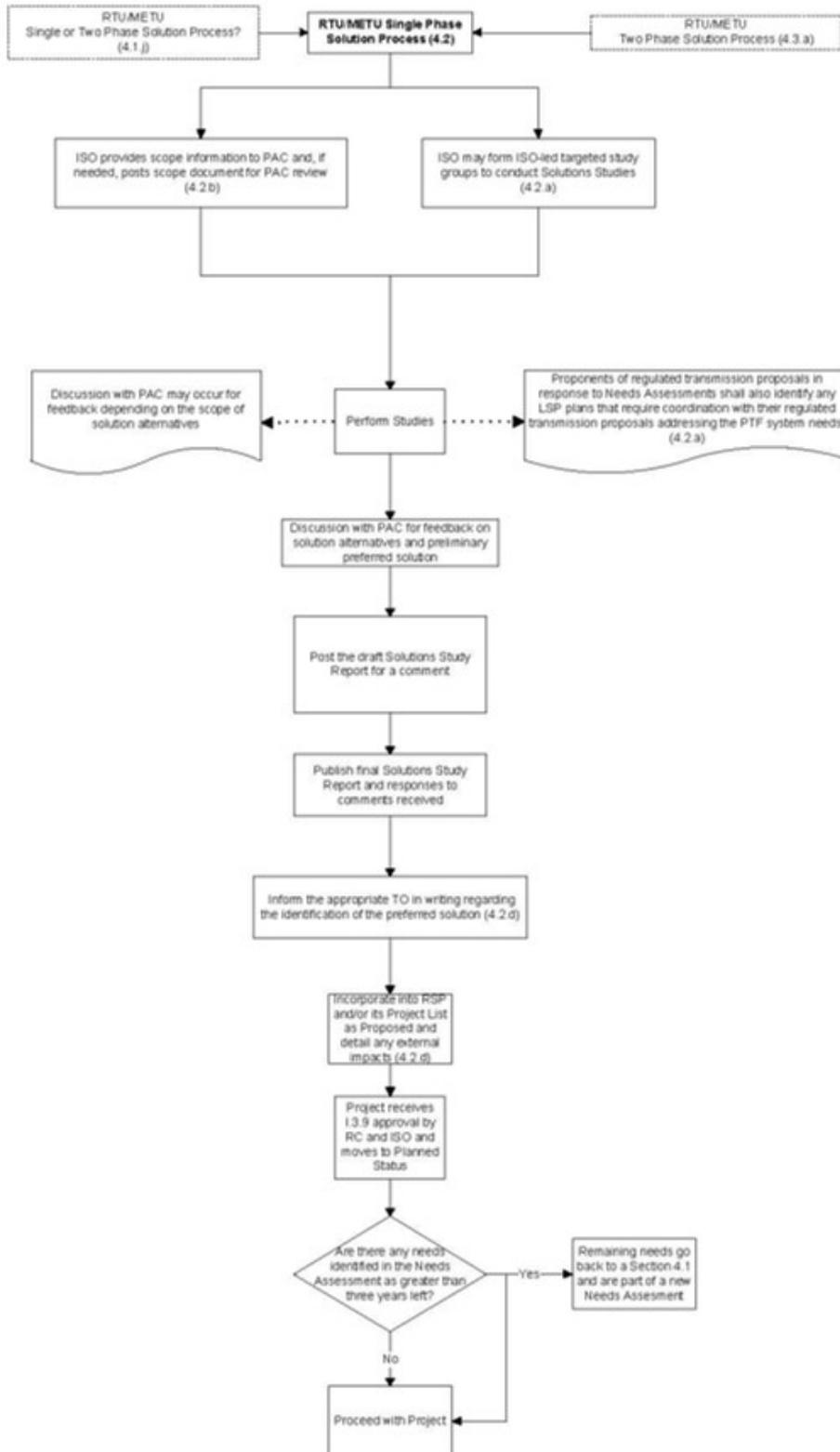
**Figure D - 1. ISO-NE RTU and METU Needs Assessment Process**

Source: ISO-NE (2016j). Transmission Planning Process Guide.



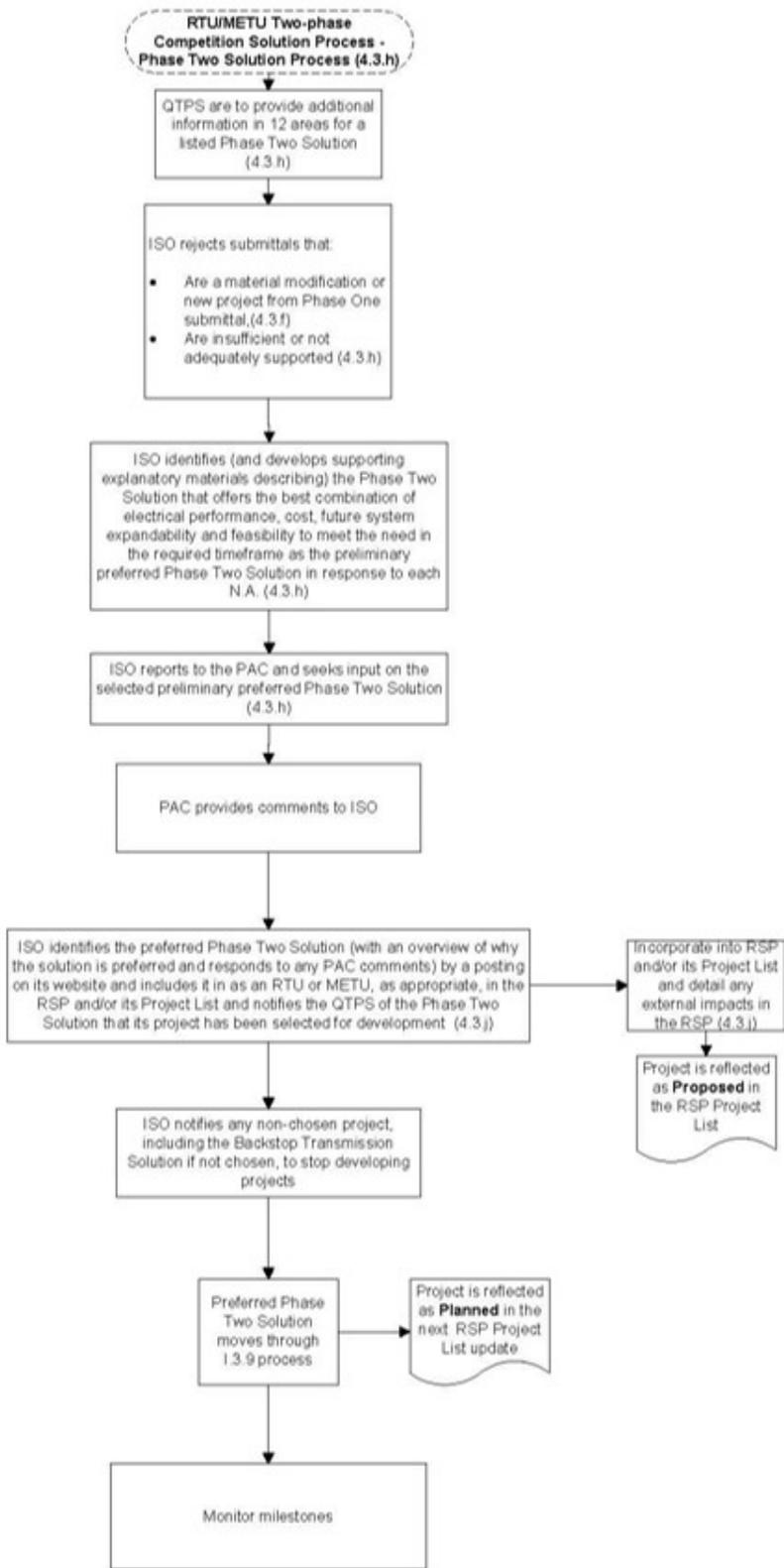
**Figure D - 2. ISO-NE RTU-METU Single or Two-Phase Solution Process**

Source: ISO-NE (2016j). *Transmission Planning Process Guide*.



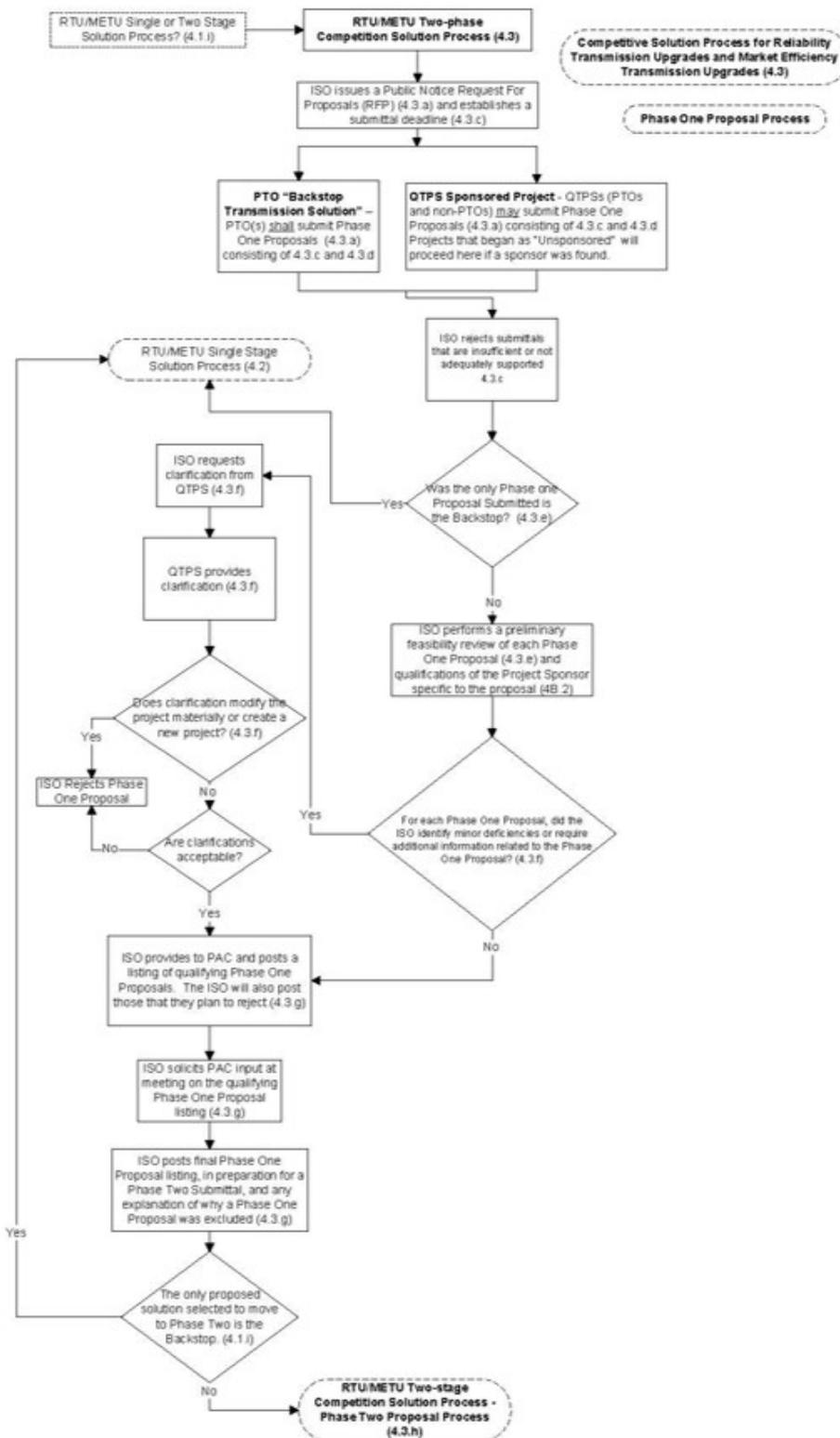
**Figure D - 3. ISO-NE RTU-METU Single Phase Solution Process**

Source: ISO-NE (2016j). *Transmission Planning Process Guide*.



**Figure D - 4. ISO-NE RTU-METU 2-Phase Competition**

Source: ISO-NE (2016j). *Transmission Planning Process Guide*.



**Figure D - 5. ISO-NE RTU-METU 2 Phase Competition Solution Process**

Source: ISO-NE (2016j). Transmission Planning Process Guide.

## Acronyms and Abbreviations

CELT	Capacity, Energy, Loads, and Transmission
EEFWG	Energy-Efficiency Forecast Working Group
ETU	Elective Transmission Upgrade
FERC	Federal Energy Regulatory Commission
ISO-NE	ISO New England
LSE	Load-Serving Entity
METU	Market Efficiency Transmission Upgrade
NERC	North American Electric Reliability Corporation
NESCOE	New England State Committee on Electricity
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PC	Planning Coordinator
PJM	PJM Interconnection
QTPS	Qualified Transmission Project Sponsor
RC	Reliability Coordinator
RSP	Regional System Plan
RTO	Regional Transmission Organization
TP	Transmission Planner

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## Appendix E. Midcontinent Independent System Operator (MISO)

### Summary

The Midcontinent Independent System Operator (MISO) operates the high-voltage power system, administers a centralized market for wholesale power, and conducts power system planning for all or portions of fifteen Midwest and South-Central states (Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, North Dakota, South Dakota, Texas, and Wisconsin). MISO conducts transmission planning studies that, among other things, lead to the identification of project classifications for cost allocation purposes. These project types currently include (1) baseline reliability; (2) other; (3) Market Efficiency; (4) Multi-Value; (5) generation interconnection; (6) transmission delivery service; and (7) market participant funded. The economic evaluation of projects considers the potential value of projects over a number of benefit metrics that may include economic congestion costs, overall system production costs, capacity savings, deferred transmission investments, and others. MISO conducts scenario analysis and relies on a formal weighting of scenario outcomes in evaluating these impacts.

### Background

MISO was formed in 1998 in response to the passage of the federal Energy Policy Act of 1992, which removed barriers to competition in the wholesale generation of the electricity business. MISO has conducted transmission planning studies since its inception. Regional cost allocation for projects began in 2006 for baseline reliability projects,<sup>22</sup> and was expanded to include market efficiency projects in 2007 and multi-value projects in 2010. Thus, regional transmission planning in MISO (including cost allocation for projects) largely pre-dates Federal Energy Regulatory Commission (FERC) Order No. 890.

FERC Order No. 1000 has resulted in two major changes to MISO's transmission planning processes. First, MISO now provides for a "competitive solicitation" process to select among qualified non-incumbent and incumbent transmission developers for transmission solutions selected by MISO as the more efficient or cost-effective solutions to regional transmission needs (Market Efficiency and Multi-Value projects) through an open competitive process. Second, MISO has now formalized arrangements for interregional transmission coordination with its neighbors.<sup>23</sup> A third major change brought about by FERC Order No. 1000—transmission required to consider public policy requirements—has not resulted in major changes for MISO because public policy considerations have always been included in the identification of long-term plans via the scenario-driven planning process. MISO's Order No. 1000-compliant regional transmission planning process and cost allocation provisions became effective for the region in January 2014.

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<sup>22</sup> The cost of baseline reliability projects ceased to be allocated regionally starting in 2013.

<sup>23</sup> MISO's interregional transmission coordination activities are not the focus of this report and are not be discussed further in this summary.

MISO's footprint expanded dramatically in late 2013 with the integration of Entergy and other entities operating in Arkansas, Louisiana, Mississippi, and Texas. As a result, during a five-year transition period which will end in 2019, some planning and cost-allocation activities have been conducted for two distinct geographic regions within MISO (north-central and south). The chief distinction during the transition period is limits on cost sharing for projects between the two sub-regions as a result of historic design practices.<sup>24</sup>

## Regional Transmission Planning

The results of MISO's planning processes are summarized annually in the MISO Transmission Expansion Plan (MTEP). Of the seven types of projects included in the MTEP, this summary focuses only on four types: *baseline reliability*, *other*, *Market Efficiency*, and *Multi-Value* projects—with an emphasis on the last two types because they represent projects whose costs may be allocated regionally.<sup>25</sup>

*Baseline reliability* and *other* projects are projects that are proposed and submitted by the transmission owners within the region; they are mentioned here briefly because they have had or are related to projects whose costs may be allocated regionally. Baseline reliability projects are ones that are needed to meet North American Electric Reliability Corporation (NERC) reliability criteria. MISO is the NERC-registered Planning Coordinator (PC) for the Transmission Planners (TPs) within the region. As noted, some of the costs for some baseline reliability projects were allocated regionally up until 2013.

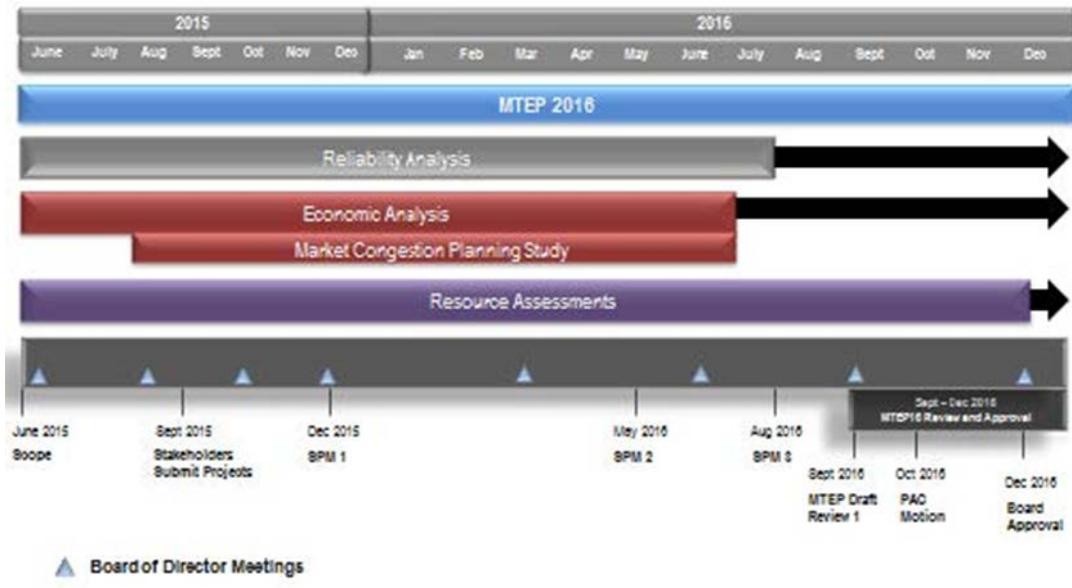
*Other* projects are ones that meet a variety of local needs, such as aging equipment, transmission issues at less than NERC bulk electric system voltage levels (generally under 100kV), and sometimes local area driven economic criteria. MISO's economic study process (described below) may also lead to the identification of "other economic," as well as market efficiency projects, with the latter meeting eligibility thresholds for regional cost allocation.

MISO's planning process is conducted through overlapping 18-month periods. See Figure E - 1. The core activity of each study process is the updating and creation of powerflow and dynamic models for reliability analysis and production cost models for economic analysis. The remainder of this discussion focuses on MISO's economic analysis.

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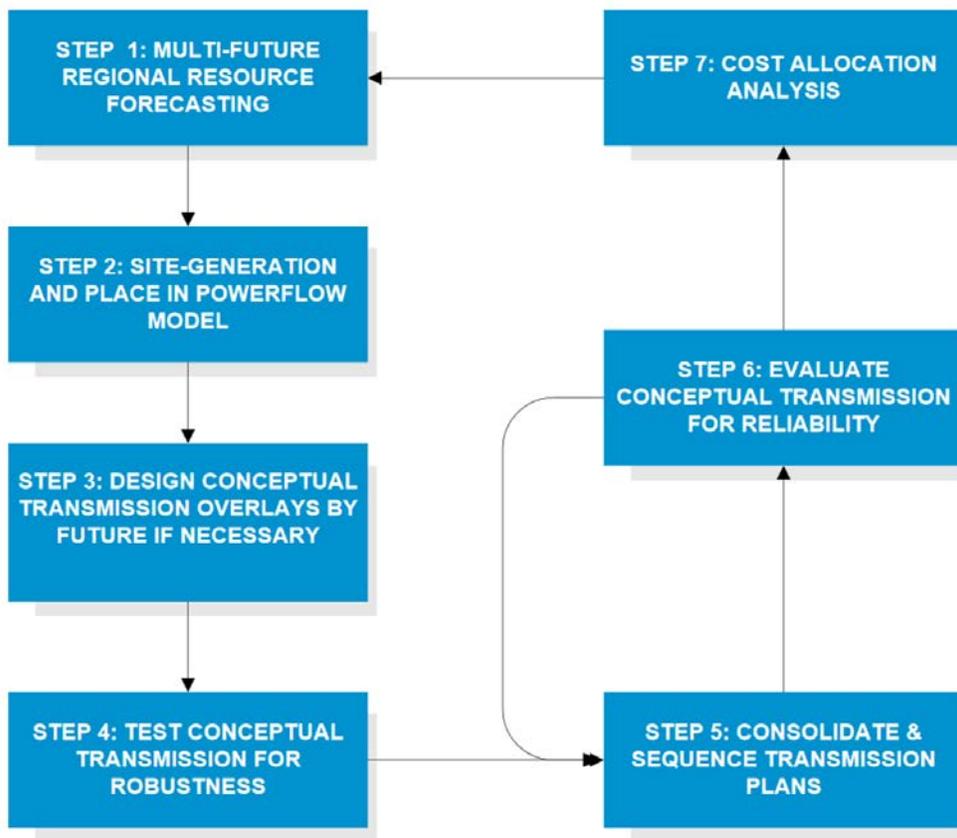
<sup>24</sup> The northern portion of the system was developed as a 765/345/138kV system; the southern portion of the system was developed as a 500/230/115kV system.

<sup>25</sup> In fact, some generator interconnection projects may also have a portion of their costs allocated regionally. However these projects are not the focus of this report.



**Figure E - 1. MTEP16 Timeline**

Source: MISO (2016c). Transmission Expansion Plan 2016 (MTEP16).



**Figure E - 2. MISO Value-Based Planning Steps**

Source: MISO (2016c). Transmission Expansion Plan 2016 (MTEP16).

MISO’s regional transmission planning process combines a top-down and bottom-up approach. The top-down “value-based” transmission planning process utilizes scenarios and seeks to identify a robust portfolio of transmission solutions to enhance market efficiency and support state and federal public energy policies. The process may lead to recommendations of Market Efficiency Projects or Multi-Value Project (MVP) portfolios. The value-based planning process consists of seven steps (see Figure E - 2).

- *Step 1: Futures Development and Regional Resource Forecasting*

To account for out-year public policy and economic uncertainties, MISO collaborates with its stakeholders to develop a broad set of future scenarios, providing plausible long-term views of the future resource mix given different policy and economic decisions. The input assumptions and uncertainty variables defined for each future are used to develop a regional resource forecast (i.e., generation expansion plan) 5–20 years into the future, which meets regional resource adequacy requirements on a least cost basis.

- *Step 2: Regional Resource Forecasting Generation Siting*

Future generation units from the regional resource forecasting process are then sited within all planning models. MISO applies a rule-based siting methodology that ties each resource to a specific bus in the powerflow model.

- *Step 3 Conceptual Transmission Overlay Development by Future*

Following regional resource forecasts developed in Step 1 and 2, conceptual transmission overlays are developed for each future scenario. The design of the overlays relies on a suite of reliability and economic information, including reliability constraints, energy source/sink plots, locational marginal price forecasts, historic and forward-looking congestion reports, and optimal incremental interface flows. The overlays are developed and refined through an iterative process, based on solution ideas received from stakeholders or generated by MISO staff.

- *Step 4: Test Conceptual Transmission Overlays for Robustness*

The preliminary transmission overlays, which were developed initially in isolation from one another are then individually assessed for all scenarios using a common set of value measures (e.g., production and congestion impacts). The collective results are then reviewed to evaluate the robustness of the different overlays. This form of robustness testing may also be used to evaluate and determine the best fit near-term project candidates to address near-term market congestion issues as described in the Market Congestion Planning Study section.

- *Step 5: Consolidate and Identify Candidate Regional Plan*

Projects within the conceptual transmission overlays, as long-term roadmaps, are then implemented in phases through a series of shorter-term solutions sequenced based on the timing considerations of policy requirements, transmission constructability, and other factors.

By consolidating and selecting the common transmission facilities among long-term conceptual overlays and other targeted studies, a candidate regional plan that is robust and compatible with a range of long-term overlay strategies is formulated.

- *Step 6: Candidate Regional Plan Business Case Analysis*

Detailed engineering analyses are then conducted to evaluate and refine the candidate regional plan derived from Step 5. Business case analysis involves a comprehensive value assessment of the candidate regional plan to capture a complete project value inclusive of economic, reliability, and policy drivers measured through a broad set of benefit metrics.

- *Step 7: Cost Allocation*

MISO employs a collection of cost allocation mechanisms that seek to match the costs of transmission investment to those who benefit from that investment. Based on the type and the distribution of the benefits derived from the proposed plan, the proper project cost allocation is determined to ensure allocated costs are roughly commensurate with the realized benefits.

This process is applied in two ways. As part of each planning cycle, MISO undertakes a Market Congestion Planning Study (MCPS). The MCPS study seeks to identify individual transmission projects to address persistent and forecasted points of market congestion. In addition to these annual reviews, MISO periodically undertakes a more holistic regional view of system needs in a multi-year planning study triggered by substantial shifts in energy policy, trends in generation portfolio changes, or other significant indicators of the potential need for a more regional portfolio of transmission development. The latter approach was applied to develop the MVP portfolio of transmission approved in 2011.

The MCPS involves first identifying the top congested flowgates across the region or within a study region; conceptual transmission solutions are then identified to relieve this congestion. Production cost modeling tools are then used to estimate the production cost savings that would result under each of the scenarios. Stakeholder-developed weighting factors are applied to results from each scenario to develop an adjusted 15-year Adjusted Production Cost (APC) savings. If the ratio of APC to the annualized cost of the solution is greater than 0.9, the solution is retained for consideration as a possible market efficiency project.<sup>26</sup>

Since the scale of transmission solutions to congestion will vary, MCPS may lead to the identification of both market efficiency projects—which might be selected for regional cost allocation because they are 345kV or larger—and “other economic” projects, which would not be eligible for regional cost allocation because they are smaller than 345kV.

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<sup>26</sup> A market efficiency project must have a benefit/cost ratio of 1.25 or greater in order to qualify for regional cost allocation.

Multi-Value Projects differ from Market Efficiency Projects by considering benefits in addition to APC savings. These benefits can include their ability to support public policy goals. These goals are often the basis for the formulation of one or more of the scenarios that are evaluated.

As described in the MISO tariff, the economic values considered for Multi-Value Projects include: (a) production cost savings; (b) capacity savings by reduction in resource planning reserve requirements; (c) capacity losses savings; (d) long-term transmission cost savings by accelerating the start date of a project or deferring otherwise needed transmission; and (e) “any other financially quantifiable benefit to transmission customers resulting from an enhancement to the transmission system related to the provision of transmission service.”<sup>27</sup>

Most importantly, the Multi-Value Project designation does not refer to an individual project. Instead it refers to a portfolio of projects whose ratio of collective benefits to collective costs is equal to or exceeds 1.25 or 1.00. Market efficiency projects must individually equal or exceed the 1.25 benefit to cost ratio.

Multi-Value Projects and Market Efficiency Projects are the two types of transmission projects for which an open competitive process is conducted in order to select developers for transmission solutions selected by MISO as the more efficient or cost effective solutions to regional transmission needs. MISO employs a “competitive bidding” approach to select a project developer. An important feature of MISO’s competitive bidding process is that developer selection occurs after the transmission planning process is completed. Eligible developers submit offers to develop only those transmission solutions selected for regional cost allocation by MISO using the planning approach described above, and after the MISO Board of Directors approves the projects as part of the MTEP regional plan. Developers who participated in the planning process leading up to identification of the solution that is the object of the competitive process are awarded a 5% credit toward evaluation of their transmission project proposal in the competitive transmission development process.

### **Recent Transmission Planning Study**

This section summarizes information drawn from a recent MISO economic planning study that was carried out as part of the 2016 MTEP (referred to as “MPTEP16”) transmission planning cycle. This review focuses on the 2016 Market Congestion Planning Study (MCPS), which is one of several studies contained in MTEP16.<sup>28</sup>

The purpose of the 2016 MCPS study is to inform stakeholders about the projected transmission congestion expected on the MISO system and economic opportunities to enhance the efficiency of the market in the planning horizon. These economic opportunities are evaluated under a broad range of economic and policy scenarios. MISO carried out two parallel economic planning efforts in MTEP16 (for the MISO North/Central and South regions).

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<sup>27</sup> MISO (2016a). *FERC Electric Tariff, Attachment FF – Transmission Expansion Planning Protocol 47.0.0*. February 2, 2016.

<sup>28</sup> See MISO (2016c), Chapter 5.3: Market Congestion Planning Study.

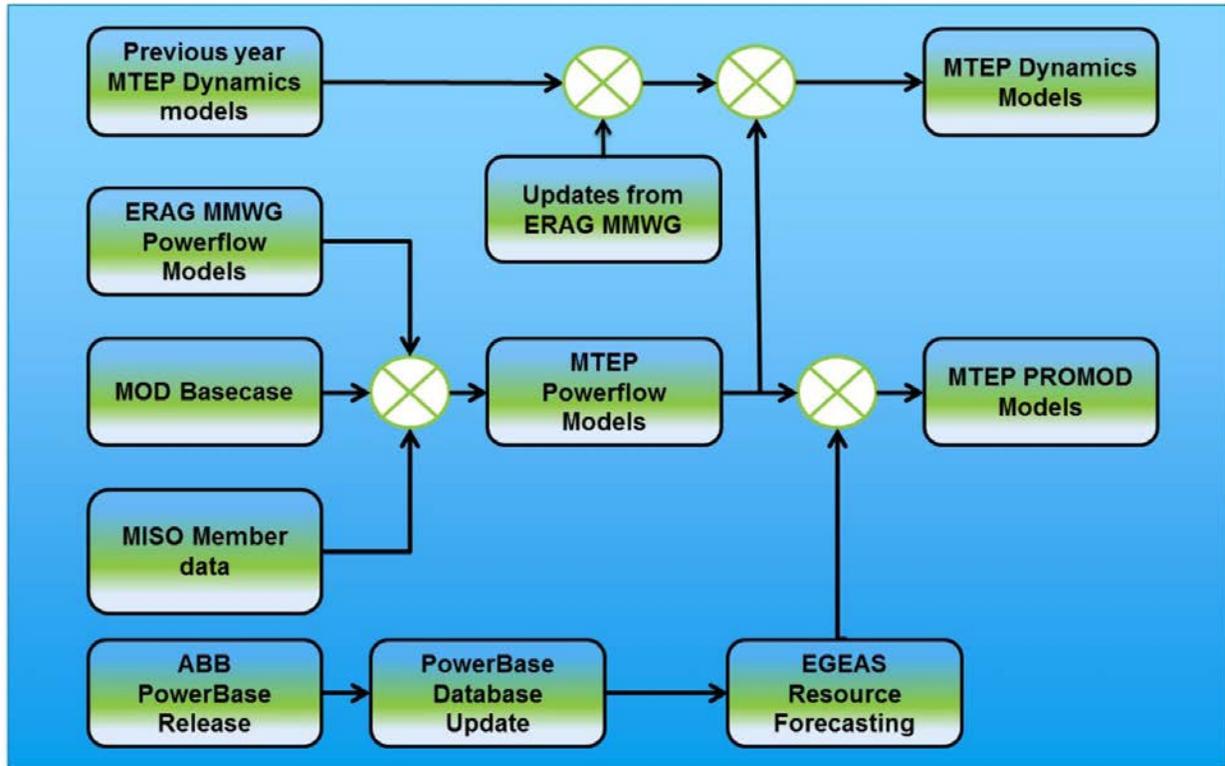
## Approach

As outlined in the previous section, MISO uses a scenario-based analysis to evaluate MTEP solutions. The future scenarios used in the MTEP16 process were:

- **Business as Usual (BAU):** This scenario assumed all current policies and trends remain in place and are unchanged throughout the study period. All current state-level renewable portfolio standard (RPS) and Energy Efficiency Resource Standard (EERS) mandates were modeled. All existing Environmental Protection Agency (EPA) regulations governing electric power generation, transmission and distribution were incorporated. A total of 12.6 GW of coal retirements were modeled.
- **High Demand:** This scenario was designed to capture the effects of increased economic growth, higher energy costs, and medium-high gas prices—as well as an increase in renewable energy over MISO’s entire footprint. RPS, EERS mandates, and EPA regulations were modeled as in the BAU scenario, as well as coal retirements.
- **Low Demand:** The Low Demand future was designed to capture the effects of reduced economic growth resulting in lower energy costs and medium to low gas prices. RPS, EERS mandates, and EPA regulations were modeled as in the BAU scenario, as well as coal retirements.
- **Regional Clean Power Plan:** This scenario focused on several key items from a footprint-wide level which, in combination, resulted in significant carbon reductions over the course of the study period. Coal retirements were augmented from the BAU levels, and were also coupled with a \$25/ton carbon cost, state mandates for renewables, and half of the energy efficiency annual growth used by the EPA, resulting in a significant reduction in carbon emissions by 2030.
- **Sub-Regional Clean Power Plan:** This scenario focused on several key items from a zonal or state level which combined lead to significant carbon reductions over the course of the study period. It is similar to the RPP scenario, except for an increase in coal retirements and a \$40/ton carbon cost.

As discussed earlier, MISO and stakeholders jointly assess and establish a formal weight to assign the outcomes from each scenario considered. The weights are used in conjunction with the APC savings measured to develop the business case for the candidate projects that MISO will ultimately recommend for board approval.

MISO’s modeling approach is outlined in Figure E - 3. The economic modeling phase of MTEP studies utilizes software tools that are updated and modified according to the scope of the analyses performed. The base data that are used in all future scenarios are maintained through the PROMOD PowerBase database; this database uses data provided annually by ABB as a starting point. In collaboration with stakeholders, MISO then goes through an extensive model development process that updates ABB’s source data with more accurate data specific to MISO.



**Figure E - 3. MTEP16 Model Relationships**

Source: MISO (2016c). *Transmission Expansion Plan 2016 (MTEP16)*.

### Findings

The 2016 MCPS North/Central study expanded a similar study from the MTEP15 process, which focused on four specific areas of high congestion. MISO and its stakeholders proposed several transmission projects to address the needs identified, and a project that addresses congestion near the border of Iowa and Minnesota was found to provide the best benefits and costs, reliability, and congestion relief, and was ultimately recommended to the MISO Board of directors for approval as a market efficiency project in MTEP16.

The 2016 MCPS South study used the progress made during the MTEP15 cycle as a springboard, and then identified several congested flowgates, and evaluated the applicable transmission solutions. The 2016 study focused on five specific areas within MISO’s South region. Unlike the North/Central region study, the projects identified and recommended for approval to the MISO board were only recommended as economic *Other* projects as part of the MTEP16 process.

### Metrics

MISO utilizes APC savings to measure the economic benefits of potential transmission upgrade options. APC savings are calculated as the difference in total production costs of a generation fleet adjusted for import costs and export revenues, with and without, the proposed transmission upgrade as part of the transmission system.

## Modeling and Selected Assumptions

**Demand and Energy:** MISO transmission owners submit load forecast information to assist in development of the reliability planning models. For long-term economic and policy planning, MISO planning staff starts with a vendor-based database (ABB PowerBase), and replaces the company peak demand and energy data provided by the vendor with the latest Module E reported data. Included in the Module E data are Interruptible Load, Direct Load Control, and ten-year projections for demand by each company. Module E load data includes losses. The demand for each Local Balancing Authority is the non-coincident value reported to MISO for resource adequacy reporting. These data are reported to MISO each year and represents the non-coincident peak demand for each company. The hourly load profile for each company relies on vendor-supplied data. Module E only provides ten years of load forecast data. Each individual company's Module E reported growth rate over the first ten-year period is averaged and extended over the remaining ten years of the study period. Individual company's annual energy requirements are calculated based on its demand and its load factor reported in the latest Module E (based on the report year's demand and energy).

MISO also produces an independent long-term load forecast via the State Utility Forecasting Group (SUF) which is currently employed for benchmarking purposes.

**Supply-side modeling:** For MISO's long-term value-based planning, scenario-based analysis provides the basis for developing economically feasible transmission plans for the future, as described previously. MISO generation resources are modeled based on the ABB PowerBase database. Stakeholders and the MISO Planning Advisory Committee (PAC) revise the database based on updated generator data, retirements, environmental and policy assumptions, etc. Future generation resource projections used in the MTEP economic models are developed using the Electric Generation Expansion Analysis System (EGEAS) model,<sup>29</sup> with assumptions developed in coordination with the PAC. This analysis develops a set of aggregated, least-cost resource expansions for each defined future scenario. Based on the different assumptions that drive the future scenarios, the least-cost portfolios project different generation resource mixes and resource retirements. EGEAS generates an expansion plan that includes conventional and renewable generation, demand response, and energy-efficiency programs. The model projects future resources in MISO and neighboring regions within the Eastern Interconnection for 40 years though MISO's planning cycle typically spans the first 15 years.<sup>30</sup> Future renewable generation (i.e., wind and solar) penetrations and RPSs are calculated using DSIRE<sup>31</sup> information for each state in the MISO footprint (several states in the MISO footprint have some form of state mandate or goal).

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<sup>29</sup> The Electric Generation Expansion Analysis System (EGEAS), created by the Electric Power Research Institute (EPRI), is the capacity expansion software tool used for long-term regional resource forecasting. EGEAS performs capacity expansions based on long-term, least-cost optimizations with multiple input variables and alternatives (MISO 2015b).

<sup>30</sup> This additional modeling step by EGEAS ensures that there are no end-effects in the resulting resource mix.

<sup>31</sup> See <http://www.dsireusa.org/>.

**Transmission system network representation:** The system network topology and the power-flow cases are taken from Model on Demand (MOD). Stakeholders post updates to resource bus mapping, contingencies, and monitored flowgates and interfaces. Power-flow models are developed for the study based on a summer peak system and contain regional information following the NERC TPL-001-4 standard.

**Environmental emissions allowances:** All future scenarios make different assumptions about CO<sub>2</sub> emissions and environmental allowances based on the different resource expansions.

In addition to the stakeholder review process, MISO collaborates with neighboring entities to develop a coordinated model that accurately reflects the neighbors’ systems. Highlights of this collaboration include extensive updates from the PJM Interconnection and Southwest Power Pool (SPP).

Table E - 1 lists key modeling assumptions used to develop the future scenarios used in MTEP16.

**Table E - 1. MTEP16 Future Scenarios and Modeling Assumptions**

MCPS Study	Future	Demand and Energy Growth	Natural Gas Price	CO <sub>2</sub>	Weight
MTEP16	Business-As-Usual	0.8%	Bentek forecast from Phase III Gas Study <sup>32</sup>	None	19%
	High Demand	1.6%	Bentek forecast from Phase III Gas Study	None	10%
	Low Demand	0.2%	Bentek Forecast -20%	None	16%
	Regional CP	0.8%	Bentek Forecast +20%	\$25/ton	30%
	Sub-Regional CPP		Bentek Forecast +20%	\$40/ton	25%

**Acronyms and Abbreviations**

APC	adjusted production cost
BAU	business as usual
EERS	Energy Efficiency Resource Standard
EGEAS	Electric Generation Expansion Analysis System
EPA	U.S., Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
MCPS	Market Congestion Planning Study
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan

<sup>32</sup> See MISO (2013) <https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/PhaseIIIGasElectricInfrastructureReportSummary.pdf>

MVP	Multi-Value Project
NERC	North American Electric Reliability Corporation
PAC	Planning Advisory Committee
PC	Planning Coordinator
RPS	renewable portfolio standard
SUFG	State Utility Forecasting Group
TP	Transmission Planner

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## Appendix F. Northern Tier Transmission Group (NTTG)

### Summary

The Northern Tier Transmission Group (NTTG) group is an unincorporated association of transmission providers and customers, working in conjunction with state representatives serving all or portions of the seven Pacific Northwestern and Mountain states of California, Idaho, Montana, Oregon, Utah, Washington, and Wyoming. A core, but not sole, activity of NTTG is to conduct regional transmission planning activities in compliance with FERC Order Nos. 890 and 1000. The evaluation of transmission projects that might be selected for regional cost allocation includes, among other factors, comparing the expected cost, energy losses, and reserve sharing benefits of a qualified sponsor-proposed project to those of the local projects it might displace.

### Background

NTTG was formed in 2007, largely in response to FERC Order No. 890. Membership in NTTG is open to public and non-public utilities, non-FERC jurisdictional transmission dependent utilities and state utility commissions, state customer advocates or state transmission siting agencies within the NTTG footprint. Participation in NTTG committees is open to all stakeholders. FERC Order No. 1000 led NTTG to develop and initiate a new planning process.<sup>33</sup> NTTG's Order No. 1000-compliant regional transmission planning process and cost allocation provisions became effective for the region in October 2013.

NTTG relies on a sponsorship model to select projects into the Regional Transmission Plan for purposes of cost allocation. At the same time, NTTG also provides opportunities for an unsponsored transmission project to be identified in the regional planning process and for stakeholders who are not potential developers to propose solutions that NTTG will evaluate. If such a solution is selected in the regional transmission plan for cost allocation as a more efficient or cost-effective solution, then the unsponsored project may, in a subsequent planning cycle, be re-proposed by a developer who has applied for and satisfied the requirements to be a qualified Project Sponsor to be considered for regional cost allocation in the next regional planning cycle.

Prior to NTTG's formation, there were no precedents for regional cost allocation among the entities participating in NTTG. To date, NTTG has not selected any transmission projects for regional cost allocation.

### Regional Transmission Planning

The focus of NTTG regional planning activities is to determine whether NTTG's regional transmission needs may be met at a regional (or interregional) scale more efficiently or cost-effectively than through

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<sup>33</sup> It is important to note that some NTTG participants are not subject to FERC jurisdiction and hence not subject to the regional transmission planning requirements of Order Nos. 890 and 1000.

the local transmission plans of the participants in NTTG.<sup>34</sup> NTTG conducts this review on a biennial basis, which leads to the preparation of NTTG transmission plan.

Preparation of NTTG's regional transmission plan involves first identifying a base plan that includes existing and future (committed and non-committed) transmission projects from the local transmission plans and NTTG's prior regional transmission plan. Next, the non-committed projects are then re-evaluated against potential regional alternatives to them. Non-committed projects are ones for which rights-of-way or permits have not yet been secured, and are subject to re-evaluation. As noted, alternative projects can include projects sponsored or proposed by qualified developers, stakeholders, and merchant transmission developers, as well as (unsponsored) projects identified by the NTTG planning committee.

The regional transmission planning process starts with the inclusion of local transmission needs driven by public policy requirements (e.g., state renewable portfolio standards) in the local transmission plans of the NTTG participants. Nevertheless, alternative projects can also be proposed for the stated purpose of meeting public policy needs. The region also has an affirmative obligation to evaluate whether there are regional transmission alternatives that are more efficient or cost-effective solutions to address these regional transmission needs.

The evaluation of alternatives is conducted via a series of change cases. A change case involves modifying the base plan, which encompasses all the projects contained in the local transmission plans and prior regional transmission plan (some of which may be the same as in the local transmission plan), by removing one or more of the non-committed projects and replacing them with one or more of the proposed alternatives.

The evaluation of change cases involves both reliability analysis and economic analysis. The reliability analysis applies North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) planning criteria to the change case. A production cost modeling tool is used to identify the dispatch of generation for specific hours of operation, which are then evaluated using a power flow reliability planning tool. Several distinct operating periods are evaluated. In order for an alternative project (or projects) in a change case to move on to the economic evaluation, the reliability analysis must show that the change case meets stated reliability criteria. The economic metric evaluation involves comparing the capital costs, the energy losses, and reserve sharing requirements associated with the change case to those associated with the base plan. The economic metric for each plan is computed as the sum of the capital related costs with the monetized energy losses and reserve sharing requirement.

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<sup>34</sup> NTTG's interregional transmission coordination activities are not the focus of this report and are not discussed in this summary.

## Acronyms and Abbreviations

FERC	Federal Energy Regulatory Commission
NERC	North American Electric Reliability Corporation
NTTG	Northern Tier Transmission Group
WECC	Western Electricity Coordinating Council

## References

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## Appendix G. New York Independent System Operator (NYISO)

### Summary

The New York Independent System Operator (NYISO) operates the high-voltage power system, administers a centralized market for wholesale power, and conducts power system planning for the state of New York. NYISO conducts planning studies that, among other things, lead to the identification of reliability needs, congested areas within the state, and potential solutions to public policy transmission needs. The identification of congested areas leads to the study of generic transmission solutions to inform market participants considering transmission (or other) projects to address this congestion.

### Background

NYISO is the direct descendent of the New York Power Pool (NYPP), which was formed after the 1965 Northeast Blackout to coordinate the operation of seven investor-owned utilities in New York [later joined by New York Power Authority (NYPA)]. NYISO was formally established as the independent system operator (ISO) for New York’s high-voltage transmission system in December 1999.

NYISO formalized its regional transmission system planning activities in 2004, which at the time were focused on integrated statewide assessment of reliability needs. NYISO began conducting routine economic analysis of areas within the state experiencing transmission congestion in 2008 following FERC Order No. 890.

FERC Order No. 1000 has resulted in two major changes to NYISO’s transmission planning processes. First, NYISO now provides for a “sponsorship” or “needs based” process to solicit, identify, evaluate, and potentially select transmission projects that are more efficient or cost-effective for regional cost allocation through an open competitive process. Second, NYISO, in conjunction with the New York Public Service Commission (NYPSC), has created a process to solicit, identify, evaluate, and potentially select competitive transmission solutions to address transmission needs required to meet public policy requirements. NYISO’s FERC No. 1000-compliant regional transmission planning process and cost allocation provisions became effective for the region in January 2014.

A third major change brought about by FERC Order No. 1000—enhanced interregional transmission coordination—has not been a major change for NYISO, because it has been participating in largely compliant interregional transmission coordination under a formal agreement with ISO New England (ISO-NE) and PJM Interconnection (PJM) since 2004.<sup>35</sup>

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<sup>35</sup> NYISO’s interregional transmission coordination activities are not the focus of this report and are not discussed in this summary.

An organizing principle of NYISO's planning activities is reliance on market-based solutions whenever possible to meet transmission needs. Regulated transmission solutions (i.e., ones whose costs would be allocated regionally) are considered only if and when market-based solutions, alone, are unable to address transmission needs. To date, NYISO has not selected a transmission project for regional cost allocation, in part, because market-based solutions or other factors have come forward to address identified transmission needs.<sup>36</sup>

## **Regional Transmission Planning**

NYISO's transmission planning activities are jointly referred to as the Comprehensive System Planning Process. This process is comprised of four activities: (1) local transmission planning; (2) reliability planning; (3) congestion assessment and resource integration; and (4) public policy transmission planning.

Local transmission planning is led by the transmission owners within New York who conduct independent planning studies for their transmission areas to address applicable criteria. These criteria focus on reliability, but also include generation interconnection, local requests for transmission service, and local transmission needs driven by public policies. The final plans by the transmission owners form the basis for the other three NYISO-led planning activities.

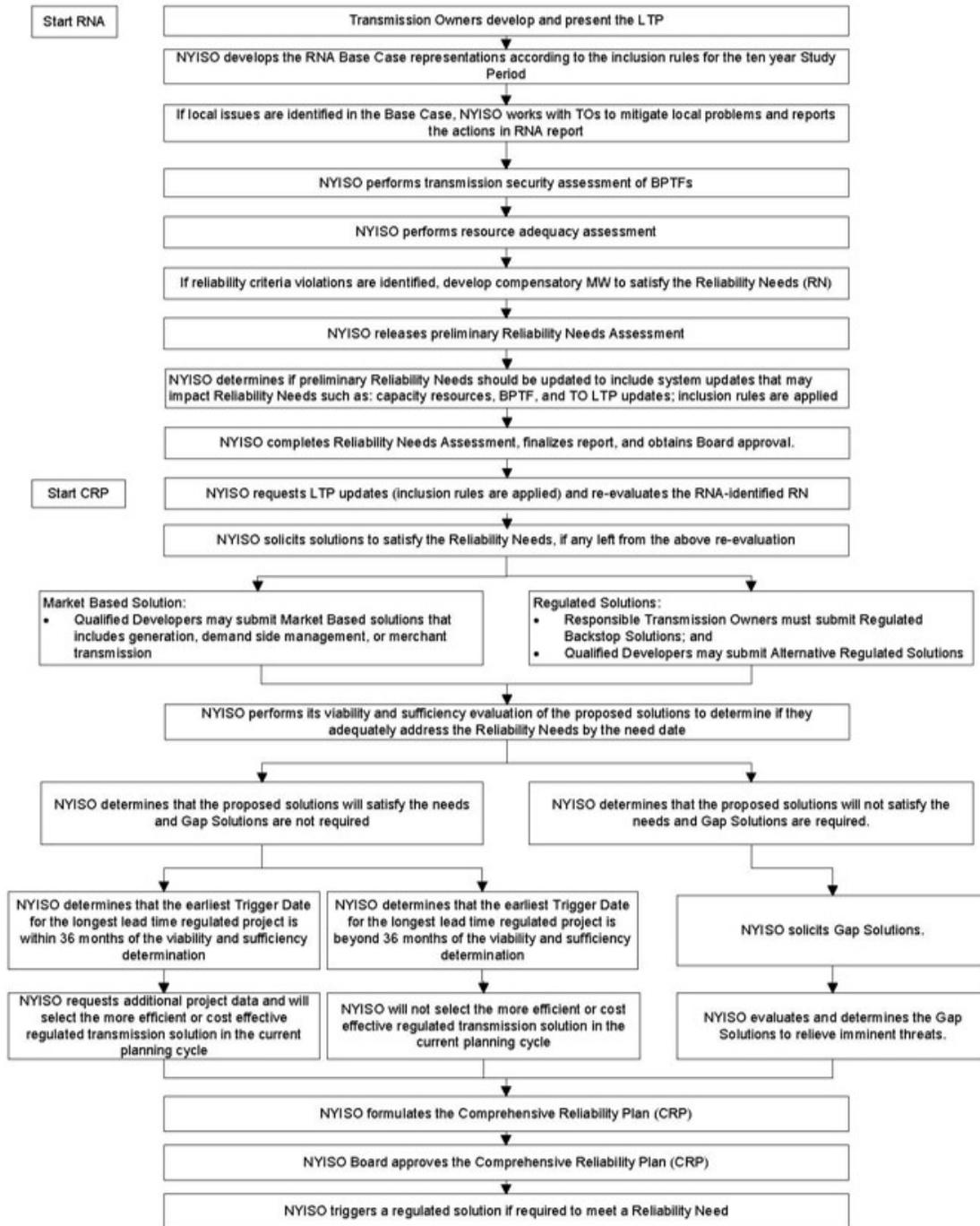
NYISO conducts reliability planning on a two-year cycle in two phases. See Figure G - 1. In the first phase, NYISO prepares a Reliability Needs Assessment (RNA) in which it integrates the local transmission plans of the New York transmission owners and conducts an integrated state-wide assessment of the adequacy of the plans according to applicable North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council, and New York State Reliability Council (NYSRC) reliability rules. The planning horizon of this assessment is ten years into the future. NYISO is the Planning Coordinator for the region and is also registered as a Transmission Planner. Generally speaking, NYISO's primary responsibility as a Transmission Planner is on bulk electric system facilities (>200kV), while New York transmission owners' primary responsibility is on lower voltage facilities.

In the second reliability planning phase, NYISO prepares a Comprehensive Reliability Plan, which reports on its findings regarding solutions to the needs it has identified in the first phase. In order to prepare the plan, NYISO concurrently requests market-based and regulated solutions from qualified developers (which include the existing transmission owners in New York). All resources (e.g., generation, transmission, and demand response) are eligible to propose solutions. NYISO then evaluates the proposed solutions to determine whether they are viable and sufficient to meet the identified reliability needs. If a market-based solution is determined to be viable and sufficient, the process ends. If not, NYISO proceeds with the evaluation and selection of the more efficient or cost-effective regulated transmission solution that meets the need. In parallel, NYISO also identifies and designates an existing

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<sup>36</sup> In 2016, NYISO issued a Solicitation of Transmission Needs driven by Public Policy Requirements and received 12 responses, which were then forwarded to the NY PSC (in accordance with NYISO tariff requirements). As of mid-2017, the PSC has not acted on the public comments it solicited on these responses.

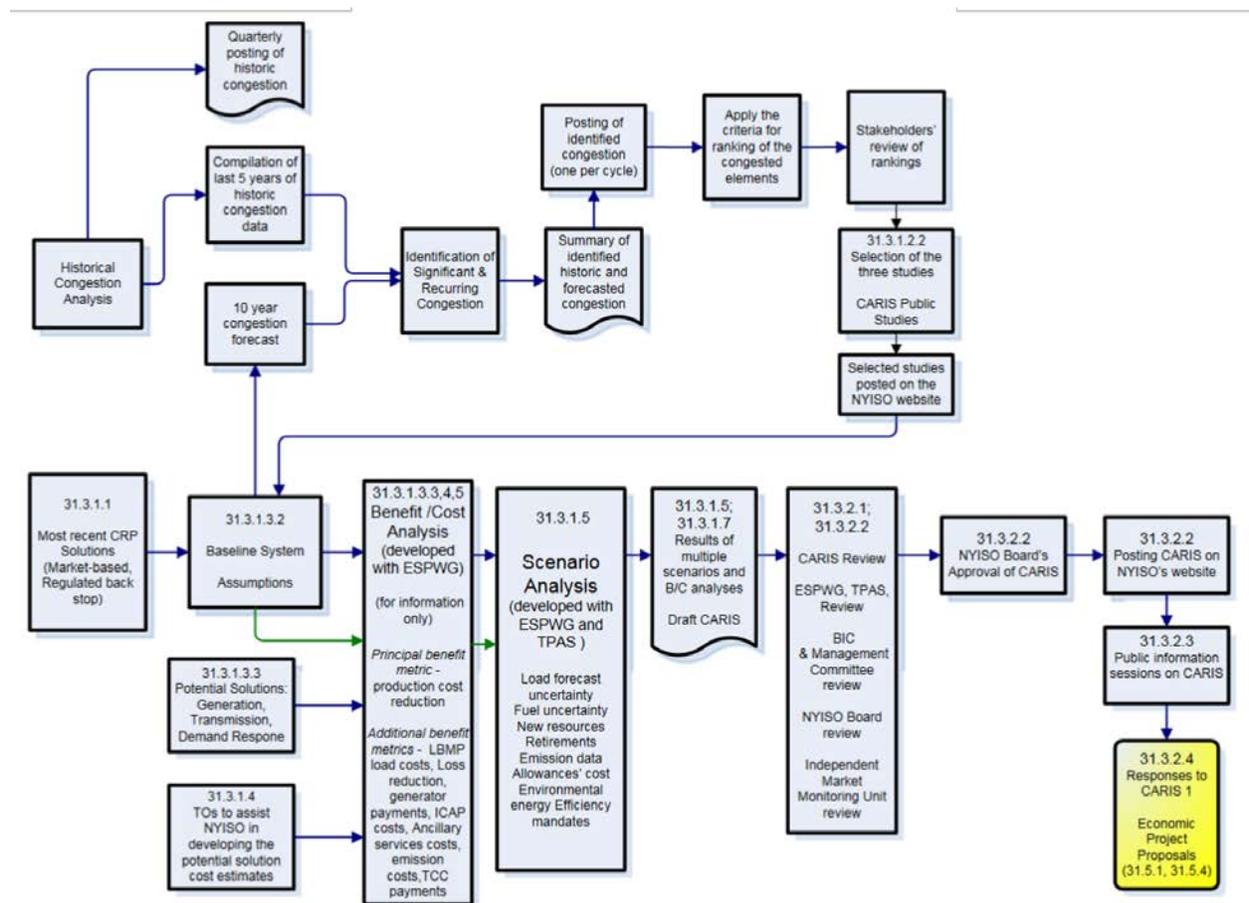
transmission owner to prepare a “back-stop” regulated solution. A regulated solution is pursued only if an identified market-based solution does not move forward in a timely manner. The results of this process are contained in a public report (called the Comprehensive Reliability Plan), reviewed by stakeholders and approved by the NYISO Board.



**Figure G - 1. NYISO Reliability Planning Process**

Source: NYISO (2016c). Reliability Planning Process Manual.

NYISO conducts economic planning on a two-year cycle, also in two phases, and in alignment with its reliability planning activities. In the first phase, NYISO prepares a Congestion Assessment and Resource Integration Study (CARIS). See Figure G - 2. The study horizon is ten years into the future and covers the same period considered in the RNA. The starting point for the analysis includes the findings reported in the Comprehensive Reliability Plan to ensure a reliable system over the ten-year planning horizon. The focus of the CARIS Phase 1 study is the identification of the three most congested areas within the state and preparation of a benefit-cost analysis of hypothetical transmission (as well as generation, demand response and energy efficiency) solutions that would address each congestion area. The purpose of the study is to inform stakeholders and would-be developers of the potential value that might be gained by pursuing market-based or regulated solutions.



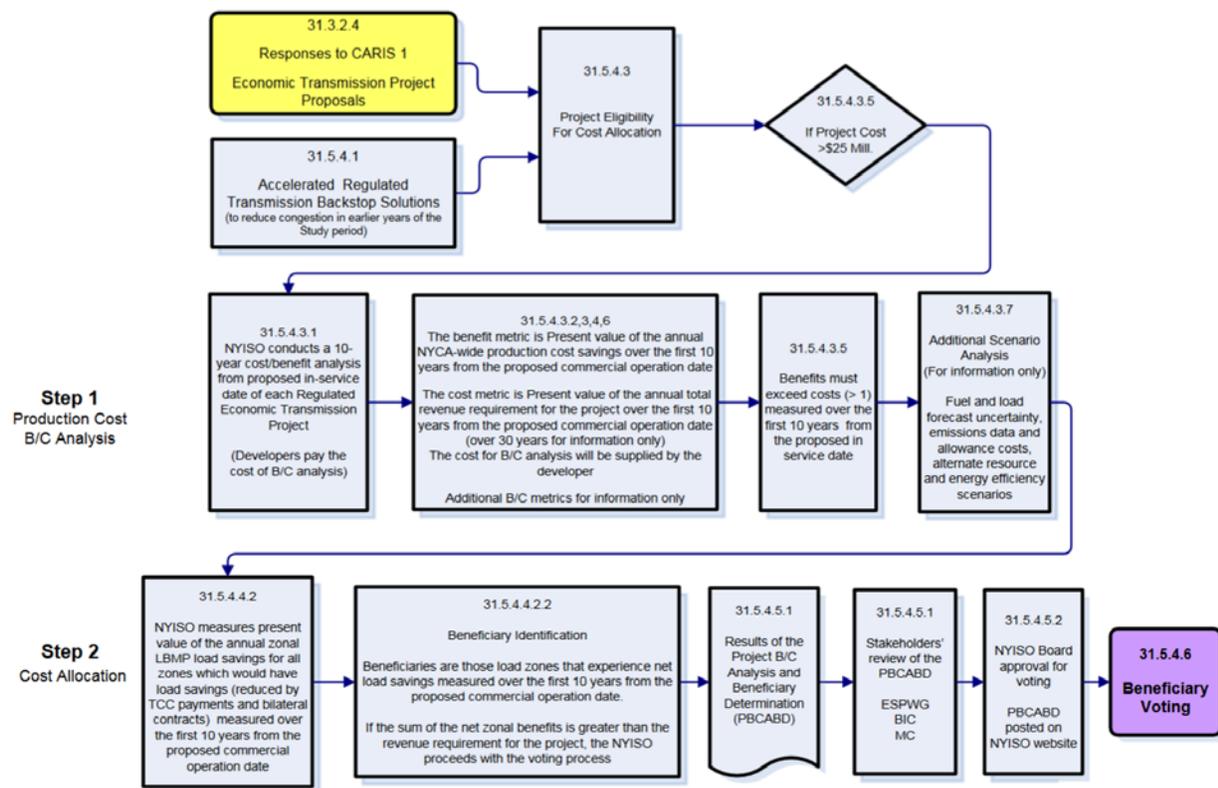
**Figure G - 2. NYISO CARIS Process Phase I**

Source: NYISO (2015c). 2015 Congestion Assessment and Resource Integration Study, CARIS—Phase 1, Appendices B-J.

The selection of congested areas for study is initially based on the five most recent historic years and projections for the next ten years. A single measure of congestion is calculated for each constrained area by aggregating the discounted annual values across the fifteen-year period. The discount rate used to calculate the present value is the current weighted average cost of capital of New York transmission owners. Congested areas are first ranked by this aggregate congestion value.

The final ranking of potential study areas is then determined based on the forecasted impact of each on system production costs. This analyses identifies whether certain constrained elements should be grouped for study to ensure that potential solutions address the full scope of the identified congestion. The constraints found in each area are iteratively relaxed until the constraint is fully relieved. The difference in production costs associated between the initial constrained case and final unconstrained case are used to establish the value of relieving the constraint. The areas with the three highest values are selected for the study of potential solutions.

NYISO then evaluates the costs of each of four generic solutions to relieve the congestion in each area: generation, transmission, demand response, and energy efficiency. While differences in system production costs are the primary benefit metric considered in assessing the cost effectiveness of the generic solutions, other related benefit metrics are also developed and provided as additional information for stakeholders to consider. These include: location-based marginal prices, load costs, loss reduction, generator payments, ICAP payments, ancillary services costs, emission costs, and transmission congestion contract costs. In addition to a base case, NYISO also conducts scenario analysis.



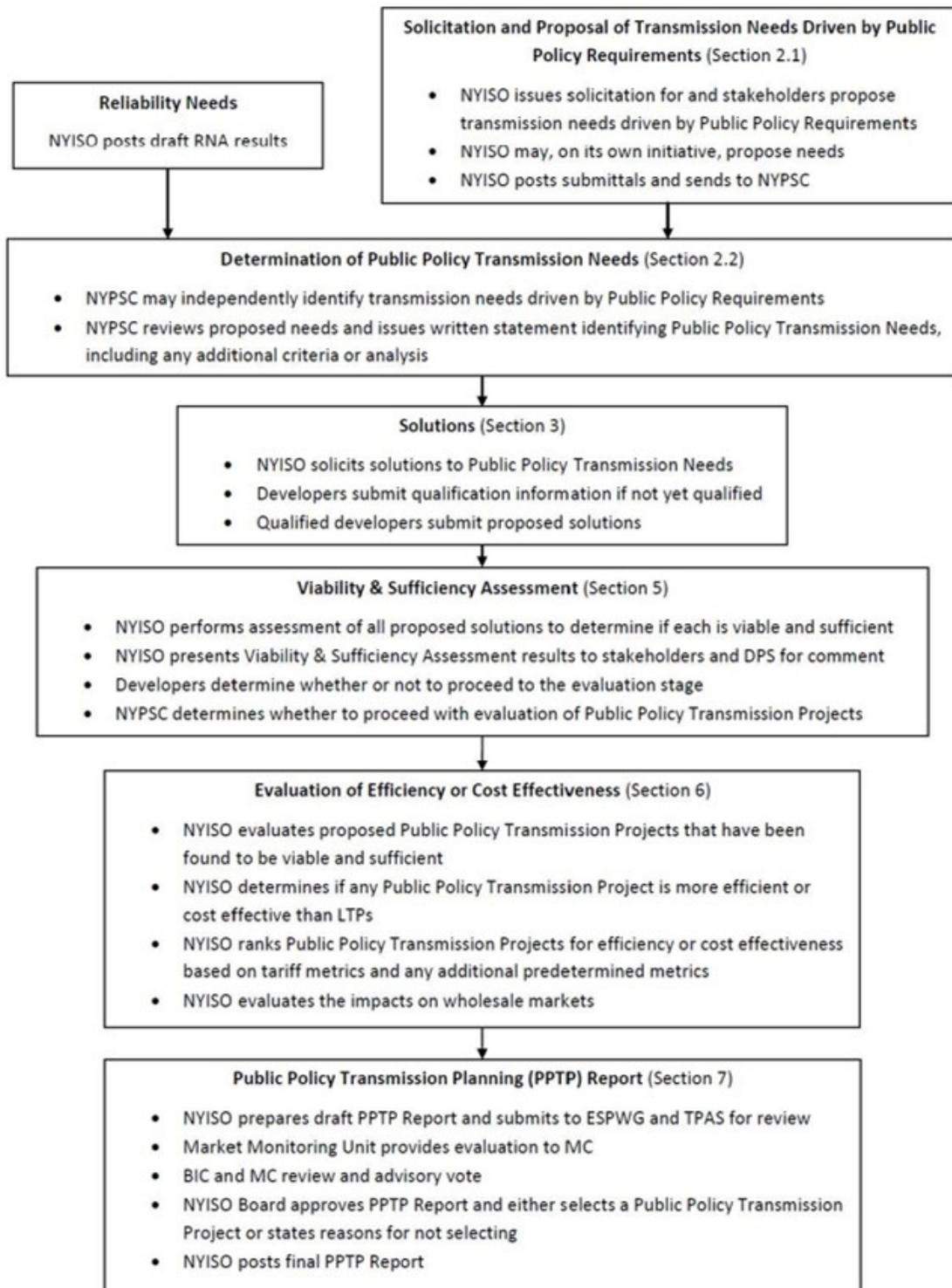
**Figure G - 3. NYISO CARIS Process Phase II**

Source: NYISO (2015c). 2015 Congestion Assessment and Resource Integration Study, CARIS—Phase 1, Appendices B-J.

If a developer proposes an economic transmission project to address one of the congested areas, NYISO initiates the second phase of its economic planning process. See Figure G - 3. The second phase involves two sequential steps of analysis. In the first step, NYISO determines whether the net benefits of the project are positive. Net benefits are calculated as the difference in ten years of production costs compared to ten years of project revenue requirements. If the net benefits are found to be positive, the project proceeds to a second step where regional cost allocation is determined. In the second step, NYISO determines whether the sum of net zonal benefits is greater than revenue requirements for the project. Net zonal benefits are calculated as the present value of the differences in annual zonal location-based marginal prices for the zones that would have load savings, reduced by transmission congestion contracts and bilateral contracts. If there are net zonal benefits statewide, the study results are reviewed with stakeholders and are submitted to the NYISO Board for approval of the study results. Following that, the project will move forward subject to a supermajority vote of the beneficiaries in favor of the project.

NYISO initiates a public policy transmission planning process following the release of the draft RNA. The process involves four steps. See Figure G - 4. First, transmission needs driven by public policy requirements are identified. Both stakeholders and NYISO may propose needs. The NYPSC, which may also introduce needs on its own, reviews these proposals and makes a final determination on the transmission need that NYISO will seek to address.

The NYPSC may also direct NYISO to take specific considerations or criteria into account in its evaluation of proposed solutions. Second, transmission and non-transmission solutions to meet these needs are proposed by qualified developers. Third, proposed solutions are evaluated by NYISO to establish whether they are viable and sufficient to meet the identified needs. Fourth, following review and approval of the viability and sufficiency analysis by the NYPSC, NYISO conducts an evaluation to select the more efficient or cost-effective transmission solution. NYISO's evaluation is based on project cost (such as capital cost and cost per megawatt) and other considerations per the NYISO Tariff, including those directed by the public service commission.



**Figure G - 4. NYISO Public Policy Transmission Planning Process**

Source: NYISO (2015e). *Public Policy Transmission Planning Process Manual*.

## Recent Transmission Planning Study

This section summarizes information drawn from a recent NYISO economic planning study carried out as part of the 2015 CARIS Phase 1 study (NYISO 2015a).

The 2015 CARIS Phase 1 study assessed historic (2010–2014) and projected (2015–2024) congestion on the New York Control Area (NYCA) bulk-power transmission system, using the CROS and the GE MAPS production-cost modeling tools to represent the operation of the NYISO-operated grid. This study provided an analysis of the potential costs and benefits of relieving the congestion identified on the grid, by using generic projects (generation, transmission, demand response, and energy efficiency) as solutions to such congestion—as opposed to specific and tailored solutions for each of the congested areas. The study analyzed the three most congested transmission interfaces<sup>37</sup> in the NYCA region where the generic solutions are applied.

### Approach

The 2015 CARIS Phase 1 study looked at historical and projected congestion within the NYCA footprint and ranked the congested elements based on the level of “demand dollar congestion” (measured in \$M, as reported in Table G - 1, and which measures the cost of congestion in a resource/load zone paid by customers). Ranking was based on the highest present value of congestion over the fifteen-year study period (five historical years and ten projected years). The study also reports the number of congested hours among the congested elements.

NYISO assessed the ranked constraints and identified potential groupings of them; the groupings for the top-ranked constraints determined the benefit-cost and sensitivity analyses to be completed during the study. The assessment was conducted in two steps: in Step one, the top-five congested elements are ranked in descending order based on the calculated present value of demand dollar congestion for the fifteen-year study period; congested elements whose projected demand dollar congestion is observed to be greater than historical demand dollar congestion may also be included in Step two.

In Step two, the top congested elements from Step one are relieved by relaxing their limits independent of one another. If new limiting elements appeared with significant congestion when a primary element’s congestion was relieved, this indicates the need to group congested elements. The groupings are then ranked based upon the greatest change in production cost, and the three groupings with the largest change in production cost are selected for study. After the ranking process, NYISO studies the impact of generic transmission, generation, demand-response, and energy-efficiency solutions that could be applied to or substituted for the congested element(s).

Depending on the type of generic solution under study, NYISO develops three estimates for total project costs (low, mid, and high), developed in collaboration with the NYCA transmission owners and informed by publicly–available data such as in industry studies and specific project proposals.

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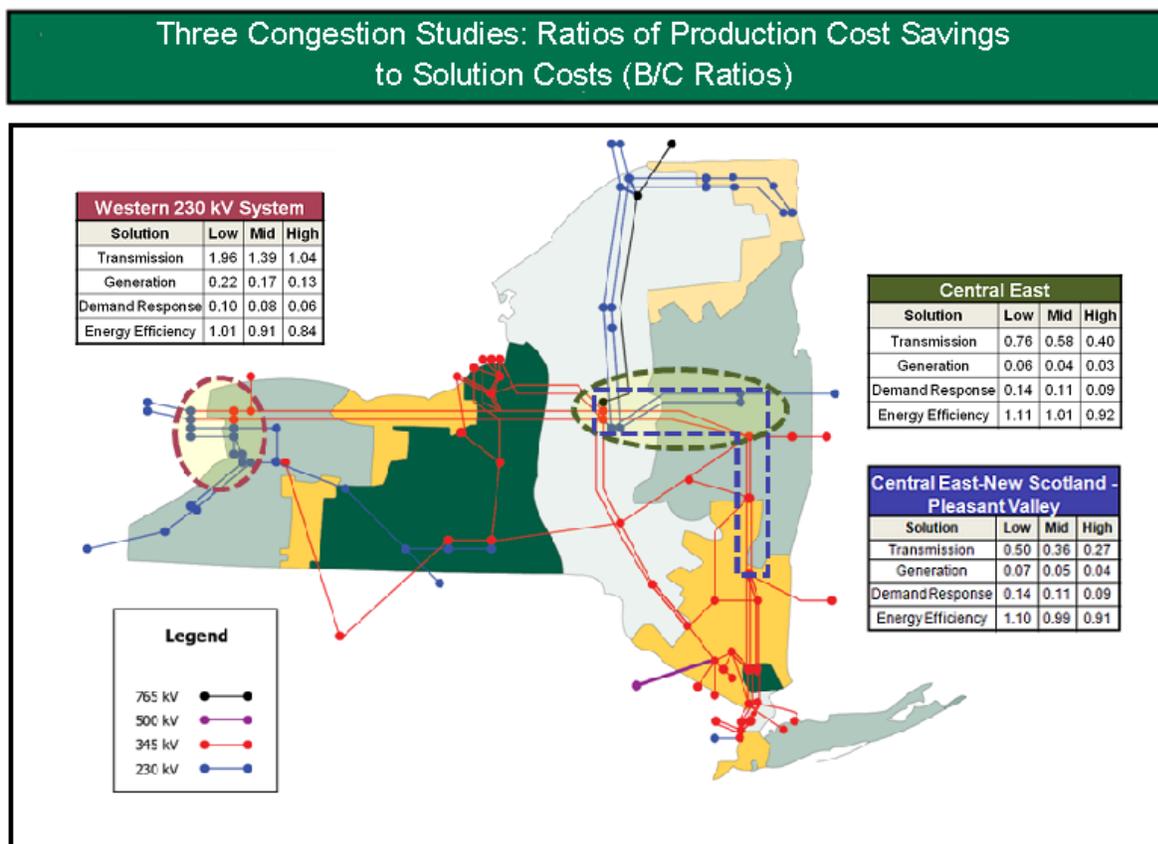
<sup>37</sup> These projects can be either a single element or a group of elements.

## Findings

The 2015 CARIS Phase 1 identified three areas for study: Central East–New Scotland–Pleasant Valley (Study 1); Central East (Study 2); and the Western 230kV System (Study 3).

Overall, the Study found that, of the four generic solutions, transmission has by far the greatest impact on reducing demand dollar congestion because it addresses the underlying constraint that causes the congestion. Energy efficiency measures and generation additions are less impactful than transmission solutions but are still associated with significant reductions in system congestion. Demand response minimally decreases demand dollar congestion because it impacts only the top-100 load hours.<sup>38</sup>

After evaluating generic solutions, NYISO used the NYCA-wide production costs to analyze costs and benefits for each of the three congested areas and each individual proposed generic solution. Figure G - 5 presents the benefit-cost ratios for each of the solutions for each of the three studies. Last, NYISO performed a sensitivity analysis of the generic solutions under the influence of different variables (e.g., natural gas prices, emissions costs).



**Figure G - 5. Generic Solutions Benefit/Cost Ratios (Low, Mid and High Cost Estimates)**

Source: NYISO (2015b). 2015 Congestion Assessment and Resource Integration Study. Comprehensive System Planning Process (CARIS) – Phase 1.

<sup>38</sup> See Figures 5, 6 and 7 in the Executive Summary of (NYISO 2015b), pages 14-15.

## Metrics

The metrics used to assess the impact of solutions are production-cost savings; impact on demand congestion (or energy expenses); emissions costs; generator payments; and installed capacity savings. Table G - 2 shows the CARIS metrics.

**Table G - 1. CARIS Economic Metrics**

Metric	Description
<b>NYCA Production Cost Savings</b>	This is the primary metric used to evaluate potential transmission-system changes and addition of new types of resources (not limited only to transmission). NYCA-wide production-cost savings are those associated with generation resources in NYCA and the costs of incremental imports/exports priced at external proxy generator buses of the solution case.
<b>Benefit/Cost ratio</b>	This metric assumes a levelized generic carrying charge of 16.26% for transmission and generation solutions and reflects generic capital costs. It is computed using the present value of production-costs savings divided by overnight costs multiplied by the capital recovery factor (1.27). The recovery factor is also based on the first 10 years of a 30-year period defined by the tariff. The discount rate is 6.843%.
<b>Demand Dollar Congestion (\$M)</b>	This metric represents the congestion component of load payments, which ultimately represents the cost of congestion to consumers. For a load zone, the demand dollar congestion of a constraint is the product of the constraint shadow price, the load zone shift factor (SF) on that constraint, and the zonal load. For NYCA, the demand dollar congestion is the sum of all of the zonal demand dollar congestion.
<b>Reduction in Losses (\$M)</b>	This metric calculates the change in marginal loss payments. Loss payments are based on the loss component of the zonal Locational-Based Marginal Prices (LBMP) load payments.
<b>Load Costs (\$M)</b>	This metric reflects the change in total load payments, which include LBMP price components (energy, congestion, and losses) paid by electricity demand (load, exports, and wheeling).
<b>Generator Payments (\$M)</b>	This metric reflects the change in generation payments by measuring only LBMP payments (energy, congestion, losses). Thus, total generator payments are calculated for this information metric as the sum of the LBMP payments to NYCA generators and payments for net imports. Imports are consistent with the input assumptions for each neighboring control area.
<b>Installed Capacity (ICAP) Costs (\$M)</b>	The latest available information from the installed reserve margin (IRM), locational capacity requirement (LCR), and Installed Capacity (ICAP) demand curves are used to calculate this metric. NYISO first calculates the megawatt (MW) impact of the generic solution on the Loss of Load Expectation (LOLE), then forecasts the ICAP cost per MW-year point on the ICAP demand curves in the rest of the state and in each locality for each planning year. There are two variants for calculating this metric, both based on the MW impact. <sup>39</sup>

<sup>39</sup> For more detail on this metric see the Section 31.3.1.3.5.6 of the Tariff.

Metric	Description
<b>Emissions Costs (\$M) – Emissions (1,000 Ton)</b>	This metric captures the change in the total cost of emissions allowances for carbon dioxide, nitrogen oxides, and sulfur oxide on a zonal basis. Total emissions costs are included in production costs and are reported separately from production costs. Emissions costs are the product of forecasted total emissions and forecasted allowance prices.
<b>Payments (\$M)</b>	The Transmission Congestion Contracts (TCC) Payment is the change in total congestion rents collected in the day-ahead market. In CARIS Phase 1, it is calculated as (Demand Congestion Costs + Export Congestion Costs) – (Supply Congestion Costs + Import Congestion Costs). This is not a measure of the Transmission Owners’ TCC auction revenues. <sup>40</sup>

### Modeling and Selected Assumptions

**Generic solution costs.** The generic solutions evaluated in each study have specific characteristics defined in the NYISO tariff. The costs of developing these generic solutions are based on available public information and reviewed by stakeholders. The main features of these generic solutions are a typical megawatt-block size, a standard set of assumptions (location and technical details of the generic solution), and order-of-magnitude costs for each resource. Table G - 2 through Table G - 4 give examples of the block sizes of the 2015 CARIS generic solutions.

**Table G - 2. Transmission Block Sizes**

Location	Line System Voltage (kilovolts)	Normal Rating (MVA)
Zone F-G <sup>41</sup>	345	1986
Zone A	230	566

**Table G - 3. Generation Block Sizes**

Location	Plant Block Size Capacity (MW)
Zone A-G	330

**Table G - 4. Energy-efficiency and Demand-Response Block Sizes**

Location	Demand Response Quantity (MW)	Portfolio Type
Zone A-J	200	Energy efficiency
Zone A-J	200	Demand response

NYISO’s “Gold Book” (NYISO 2016b) contains detailed information about NYCA, including the most recent data on generation and transmission facilities; and zonal and system-wide peak and energy load forecasts.

<sup>40</sup> This is calculated differently in Phase 1 than in Phase 2 of the CARIS process, as described in the NYISO Tariff.

<sup>41</sup> The zones listed in the document are available here: [http://www.nyiso.com/public/webdocs/markets\\_operations/market\\_data/zone\\_maps\\_graphs/nyca\\_zonemaps.pdf](http://www.nyiso.com/public/webdocs/markets_operations/market_data/zone_maps_graphs/nyca_zonemaps.pdf).

**Load.** NYISO develops zonal load forecasts based on regression models that reflect annual changes in economic conditions and weather. NYCA Energy and Demand Forecasts are reported net of energy savings impact.

**Energy efficiency.** Energy efficiency forecasts are developed separately from the load and energy forecast. The impacts from both existing and new energy-efficiency programs,<sup>42</sup> behind-the-meter photovoltaics (PV), and other distributed generation are included. The forecast is developed based on a regression model that reflects energy usage levels in the absence of the savings from energy-efficiency programs and distributed generation (including behind-the-meter PV).

**Supply-side modeling.** Generation retirements and new units are modeled based on updated information in the current year's Gold Book. Numerical values are provided for nameplate rating, summer capacity resource interconnection service, summer and winter capability, and net energy generated during the preceding calendar year. The NYISO forecast for solar PV impacts is based on historical data, an assumed trend of future PV installations over time, a geographical distribution of the units, and performance parameters derived from operational data. Wind resources are modeled based on unit capacities and synthesized wind shapes developed as part of NYISO's 2010 Wind Study (NYISO 2010).

**Transmission system network representation.** The power-flow cases in CARIS are based on the Comprehensive Reliability Plan. Information on interface limits, contingency pairs, nomograms, and new transmission projects is taken from the 2015 Gold Book and from results of internal and external planning studies as well as vendor-supplied data.

**Environmental emission allowances.** Fuel oil and coal price forecasts are developed from the Energy Information Administration (EIA) annual forecast of national delivered prices, and regional values are derived using EIA Form 923 data. Seasonal fuel oil prices are based on an analysis of New York Harbor ultra-low sulfur diesel prices. Coal prices are fixed and do not vary seasonally. Forecasts are developed in collaboration with the NYISO's Electric System Planning Working Group (ESPWG) for the three regions within NYCA. Carbon dioxide, sulfur oxide, and nitrogen oxides allowance prices reflect new Cross-State Air Pollution Rule markets.

**Interchange.** Interchange with neighboring areas is represented by two independent hurdle rates—one for commitment of generation and a separate one for dispatch of generation. Both commitment and dispatch hurdle rates were held constant throughout the 2015-2024 study period. The hurdle rate values produce results consistent with NYCA historic total import levels. The hourly interchange flow for each interface connecting NYISO with neighboring control areas was priced at the Locational-Based Marginal Price (LBMP) of its corresponding proxy bus. The summation of all 8,760 hours determined the annual cost of the energy for each interface. Hydro Quebec (HQ) is modeled as a fixed hourly schedule

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<sup>42</sup> New York State Department of Public Service (DPS), the New York State Energy Research and Development Authority (NYSERDA), state power authorities, electric utilities, and through NYISO's previous participation in the DPS Evaluation Advisory Group.

synchronized with all other external injections.

Except for HQ, external areas immediately adjacent to NYCA are actively modeled including unit additions, retirements, and rerates as well as fuel forecasts. Adjacent areas include ISO-NE, IESO, and PJM. Because HQ is asynchronously tied to the bulk system, proxy buses representing the direct ties from HQ to NYISO, HQ to IESO, and HQ to ISO-NE are modeled.

Table G - 5 reports selected modeling assumptions.

**Table G - 5. Selected Modeling Assumptions, Study Years 2015–2024**

Variable - Unit	Value	Source
<b>Load –Sum of Zonal Non-Coincident Peaks (GW)</b>	34GW (2015)-35.5GW (2024)	
<b>Net Annual Energy TWh</b>	160 TWh (average across the period)	2015 CARIS
<b>Peak Demand Growth Rate</b>	1.16% (from 2019 to 2024)	Appendices B-J
<b>Natural gas prices</b>	4.69 \$/mmBTU (2015), 7.64 \$/mmBTU <sup>43</sup>	
<b>Emission Allowance prices (CO<sub>2</sub>, SO<sub>x</sub>, NO<sub>x</sub>)</b>	See footnote <sup>44</sup>	

## Acronyms and Abbreviations

CARIS	Congestion Assessment and Resource Integration Study
EIA	Energy Information Administration
ESPWG	Electric System Planning Working Group
FERC	Federal Energy Regulatory Commission
HQ	Hydro Quebec
ICAP	Installed Capacity
IRM	Installed Reserve Margin
ISO	Independent System Operator
ISO-NE	ISO New England
LCR	Locational Capacity Requirement
LMBP	Locational-Based Marginal Price
LOLE	Loss of Load Expectation
NERC	North American Electric Reliability Corporation
LBMP	Locational-Based Marginal Prices
NYCA	New York Control Area
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYPP	New York Power Pool

<sup>43</sup> See NYISO (2015d). *2015 Fuel Price Forecast*.

<sup>44</sup> See NYISO (2015a). [http://www.nyiso.com/public/webdocs/markets\\_operations/committees/bic\\_espwg/meeting\\_materials/2015-05-04/Agenda%20CARIS%20Follow%20Up.pdf](http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/2015-05-04/Agenda%20CARIS%20Follow%20Up.pdf)

NYPSC	New York Public Service Commission
NYSRC	New York State Reliability Council
PJM	PJM Interconnection
PV	photovoltaic
RNA	Reliability Needs Assessment
TCC	Transmission Congestion Contracts

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## Appendix H. PJM Interconnection (PJM)

### Summary

PJM Interconnection (PJM) operates the bulk electric system, administers a centralized market for wholesale power, capacity, and ancillary services, and conducts power system planning for all or portions of the thirteen mid-Atlantic and upper Midwest states of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. It conducts planning studies that, among other things, lead to the identification of reliability, market efficiency, operational performance, and public policy needs and transmission solutions. The economic evaluation of projects, in addition to project cost, considers the benefit of projects to load payment costs, overall system production costs, and capacity market costs.

### Background

PJM was formed in 1927 through an operating agreement among three utilities in Pennsylvania, New Jersey, and Maryland, which led to the creation of the first power pool in the United States. PJM became an independent organization in 1997 and a FERC-approved Regional Transmission Operator (RTO) in 2002. PJM grew dramatically in membership after 2002 and now plans and operates the largest capacity and energy markets in North America.

PJM began conducting transmission system planning for its region in 1997, and began establishing formal rules for regional cost allocation for projects following FERC Order No. 2000. PJM began developing procedures for identifying market efficiency projects that address historic or projected future congestion following FERC Order No. 890.

FERC Order No. 1000 has resulted in three major changes to PJM's transmission planning processes. First, PJM now provides for what it refers to as a "sponsorship" process to select projects that address Regional Transmission Expansion Plan issues and regional cost allocation through an open competitive process. Second, interregional transmission coordination has become more formalized.<sup>45</sup> The third major change brought about by Order No. 1000—identifying transmission needs required to meet public policy requirements—has led to two changes for PJM, which previously considered public policies to varying degrees prior to Order No. 1000. First, Order No. 1000 formalized consideration of transmission needs driven by public policies in PJM's Multi-Driver planning process (to be discussed below). Second, PJM established a committee for states giving them a formal, standing role through which they provide input, notably on the public policy needs that PJM needs to consider in its planning process. PJM's FERC Order No. 1000-compliant regional transmission planning process and cost allocation provisions became effective for the region in January 2014.

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<sup>45</sup> PJM's interregional transmission coordination activities are not the focus of this report and are not discussed in this summary.

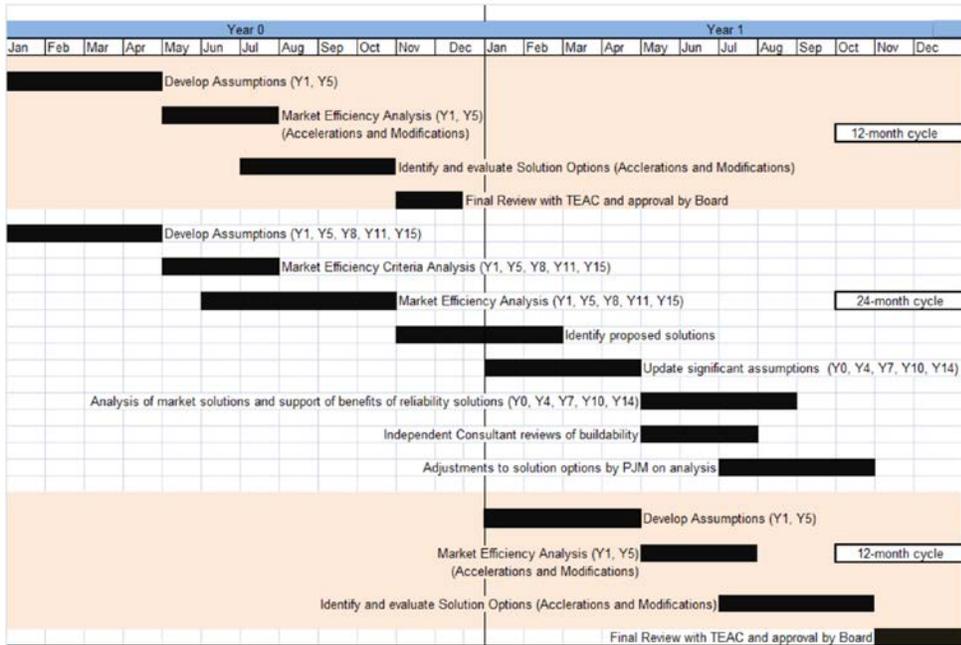
## Regional Transmission Planning

The results of PJM's planning processes are summarized annually in its Regional Transmission Expansion Plan (RTEP). The RTEP reports on the outcomes from two parallel PJM reliability planning processes that look 15 years ahead into the future. The first track is repeated annually, and is focused on identifying reliability needs for near-term transmission solutions required to be in service by year five of the planning horizon. The second track involves a two-year study process to identify reliability needs that are not required until beyond the fifth year on the horizon and may require longer lead times to put in service (e.g., because they may be larger in size compared to the near-term solutions). Most of the PJM reliability and operational performance solutions result from the annual planning cycle. PJM regional market efficiency planning occurs during the two-year cycle. An important interaction between these reliability planning tracks is the consideration of solutions that have been identified to meet near-term needs that might also be capable of meeting long-term needs—by either increasing their size or accelerating the timetable for their development.

The RTEP is comprised of four analysis streams: (1) baseline reliability analysis; (2) generation and transmission interconnection analysis; (3) market efficiency analysis; and (4) operational performance issue reviews and accompanying analysis. This review focuses on the first, third, and fourth of these analyses. PJM's Multi-Driver planning process, which integrates elements from these analysis streams as well as other sources (including consideration of transmission needs driven by public policies), will be discussed last.

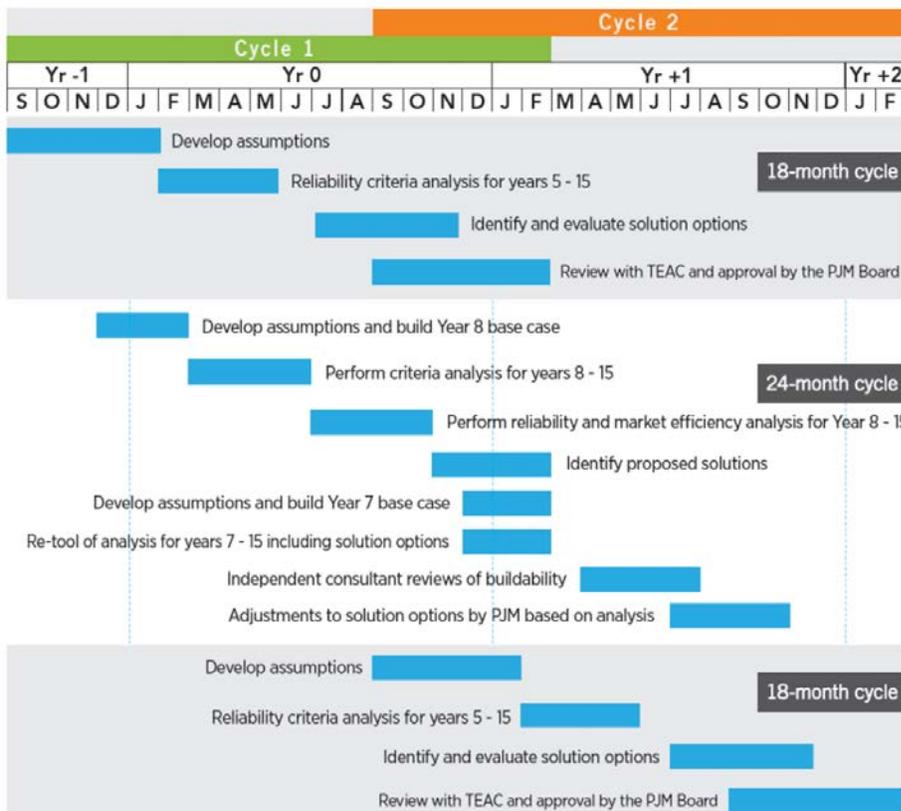
PJM's planning for reliability needs follows planning standards promulgated by the North American Electric Reliability Corporation (NERC), two regional reliability organizations (Reliability First Corporation and SERC Reliability Corporation), as well as internal standards developed by PJM and PJM Transmission Owners. PJM is the sole NERC-registered Transmission Planner for the region as well as the Planning Coordinator. This is in contrast to some transmission planning regions, which may serve as a planning coordinator, but are not the transmission planner for all of the transmission systems within their footprint.

Both the 12-month and the 24-month reliability planning cycles can lead to the identification of transmission needs and the solicitation of solutions to address these needs through an open competitive process that is termed by FERC as a sponsorship model. See Figure H - 1 and Figure H - 2. PJM's sponsorship model involves the solicitation of proposed transmission solutions from qualified incumbent and non-incumbent transmission developers in a proposal window, followed by the evaluation of proposed solutions by PJM. PJM board approval of a recommended solution confers the rights to (and obligations for) development of the solution to its proposer. Regional cost allocation for selected reliability projects follows an allocation method that relies on distribution factors among other considerations.



**Figure H - 1. PJM 24-Month Market Efficiency Cycle**

Source: PJM (2017a). PJM Manual 14B: PJM Region Transmission Planning Process.



**Figure H - 2. PJM 24-Month Reliability Planning Cycle**

Source: PJM (2017a). PJM Manual 14B: PJM Region Transmission Planning Process.

PJM's planning for market efficiency needs focuses on identifying transmission solutions that reduce projected congestion. Future congestion is assessed using security-constrained production cost simulation tools that project future congestion, including the binding constraints that lead to this congestion. PJM relies on a benefit-cost (B/C) ratio threshold that compares the present worth of 15 years of projected congestion savings to the revenue requirements of the transmission solution over the same time period. PJM's B/C ratio threshold holds that these benefits must exceed these costs by at least 25%.

While the same B/C ratio threshold must be met (savings exceed costs by 25%), the composition of benefits differs according to the source and size of the solution. PJM considers two forms of market efficiency benefits: (1) energy market benefit, and (2) reliability pricing model benefit.

The energy market benefit for Regional Facilities (500kV and double circuit 345kV and higher voltage) and Necessary Lower Voltage Facilities (i.e., facilities that operate below these voltages but must be constructed to support Regional Facilities) is comprised of 50% of the total production cost savings plus 50% of the changes to load energy payments. For Lower Voltage Facilities, the benefits are comprised solely of the changes to load energy payments. The load energy payment is the difference between the annual sum of the hourly estimated nodal load megawatts multiplied by the nodal locational marginal price for a zone minus the value of the transmission rights for each zone, summed for all zones for which this difference represents a decrease. The change in load energy payments refers to this difference with and without the transmission solution.

The reliability pricing model benefit for Regional Facilities (and Necessary Lower Voltage Facilities) is comprised of 50% of the change in total system capacity cost plus 50% of the change in load capacity payments. For Lower Voltage Facilities, the benefits are comprised solely of the changes in load capacity payments. System capacity costs are those associated with megawatts that are estimated to be cleared in PJM's capacity auction under the reliability pricing model multiplied by the costs that are estimated to be cleared in the capacity auction. Load capacity payments are the sum of zonal megawatts multiplied by the estimated final zonal capacity payments under the reliability pricing model minus the value of each zone's capacity transfer rights. The change refers to the differences in these two quantities with and without the transmission enhancement.

PJM planning for market efficiency needs also involves two sequential 12-month cycles and one overlapping 24-month cycle. The focus of the 12-month analysis is a review of congestion in Year 1 and Year 5 and existing approved RTEP projects. The goal is to determine whether acceleration or modification of an existing project, such as one identified initially to meet a reliability-driven need, would meet PJM's benefit/cost criteria for market efficiency. The focus of the 24-month analysis cycle is to identify solutions that require longer lead times to implement. As with reliability needs, an open competitive process is used to solicit proposed solutions from prospective incumbent and non-incumbent developers.

PJM also routinely conducts operational performance reviews (and analysis) to address emerging system operating issues, such as those that arose during the Polar Vortex in the winter 2013–2014. These reviews may influence other PJM study activities, such as scenario analysis, or they may lead to standalone analysis of specific topics (e.g., probabilistic risk assessment of large transformers to assess replacement strategies).

PJM’s Multi-Driver planning process represents the means by which PJM integrates (and potentially modifies or adds to) solutions emerging from the four main analysis streams, along with other considerations. The objective of the Multi-Driver planning process is to identify more efficient and cost-effective projects. By carefully assessing the various drivers for projects in combination with one another, the Multi-Driver planning process directly informs subsequent cost allocation decisions that align project costs with beneficiaries for the different drivers.

Scenario analysis plays an important role in PJM’s transmission planning analysis. Scenario studies are an important (but not the sole) means by which PJM evaluates the impacts of public policies on transmission needs. The outcomes from the scenarios are, however, not weighted to develop a composite score. Instead, results from scenario studies may be used to adjust the time when projects are needed or modify aspects of a project’s design. Hence, scenario analysis plays an important role in augmenting baseline reliability and market efficiency analysis.

## **Recent Transmission Planning Study**

This section summarizes information drawn from a recent PJM economic planning study carried out as part of the 2015 RTEP: the 2014 Market Efficiency Analysis, which was conducted during the second year of the Market Efficiency 24-month RTEP cycle. The purpose of the 2014 Market Efficiency Analysis study was to present a PJM market analysis that determines current and projected transmission congestion issues to inform stakeholder proposals submitted through the 2014–2015 RTEP Long-Term Proposal Window. The study also reviewed economic characteristics of 2013 RTEP-approved reliability projects for reliability purposes and for market acceleration.

### **Approach**

In the first year of the 24-month planning cycle (2014), PJM performed a long-term simulation using 2019 topology for the years 2015, 2019, 2022, and 2025. These simulations were carried out in order to identify and rank the top-25 congestion constraints within the system based on the frequency and costs (in \$M). PJM then used this analysis to draft a problem statement and requirements posted during the 2014–2015 RTEP Long-Term Proposal Window. Transmission owners submitted a total of 93 proposals to resolve or alleviate market efficiency congestion identified in the long-term simulation congestion studies.

PJM evaluated all proposals submitted and divided them into nine subgroups based on geographical scope and purpose. Group 1, the largest group, encompassed regional facilities aiming to address a reactive interface issue, known as the AP South Interface. Group 2 focused on facilities proposed within

the region served by Commonwealth Edison that would address an issue encompassing both capacity and energy benefits within the Commonwealth Edison load delivery zone. The remaining groups included lower-cost facilities that would address various specific locational issues. Each group was evaluated individually.

PJM first screened projects using a B/C ratio threshold (see Metrics, below); the projects that passed this threshold were assessed further for their potential to reduce, fix, or increase system congestion. These projects were then analyzed for their constructability and potential for increasing system reliability compared to a base-case year (2014). A sensitivity analysis for year 2015 looked at different forecast load levels and variations in natural gas prices. If the project did not require additional upgrades, it was recommended to the PJM board for approval; otherwise, it would go through the evaluation phase again at a later stage of the planning process.

PJM's B/C threshold test determines whether a particular upgrade is justified based on market efficiency. Market efficiency transmission proposals that meet or exceed a 1.25 B/C ratio are further assessed for their constructability and impact on system reliability. For projects with a total cost exceeding \$50 million, PJM's Operating Agreement requires an independent review of project costs and benefits to ensure consistent estimating practices and project scope development.

The B/C ratio is calculated by comparing the net present value of annual benefits determined for the first fifteen years of the life of the upgrade to the net present value of the upgrade revenue requirement for the same fifteen-year period.

## Findings

Detailed results for each of the nine groups were as follows:

- *Group 1:* Of 41 proposals, six projects that targeted PJM AP South reactive interface limit passed the initial analysis phase and were screened through the sensitivity analysis. At the end of the RTEP evaluation phase, one project proposed by a competitive transmission developer, with a B/C ratio of 15.4, was recommended for board approval.
- *Group 2:* Nine projects that aimed to alleviate a capacity delivery issue in the Commonwealth Edison load delivery zone and associated market congestion issues were screened based on the total sum of the energy and capacity benefit that each project would provide. A project that proposed to upgrade existing equipment had the highest total market efficiency benefit and was recommended for board approval.
- *Groups 3-9:* Eleven projects were recommended for approval based on a B/C ratio greater than 1.25 for both 2014 and 2015 base cases. The follow-up reliability analysis of each project further confirmed that there were no new reliability issues created by the economic project. These projects all proposed to upgrade existing equipment and were designated to the incumbent transmission owners.

## Metrics

As discussed earlier in this summary, PJM's annual benefit calculation for regional facilities combines a percentage of the system production cost benefits with a percentage of the change in net load energy payments for zones whose net load payments would decrease as a result of the proposed project. PJM's annual benefit calculation for lower-voltage facilities is comprised entirely of the decreases in zonal net load payments as a result of the proposed project. Zones for which net load payments increase because of the proposed project are excluded from the net load energy payment benefit.

## Modeling and Selected Assumptions

PJM uses a commercially available production cost model to carry out its annual market efficiency studies. The PJM Transmission Expansion Advisory Committee (TEAC) reviews the key modeling assumptions and analyses every year before initiating economic planning studies.

The PJM load forecast model is an econometric model that produces estimates of non-coincident and coincident peak loads for each PJM zone, locational deliverability area (LDA), and the RTO. It uses local economic activity, weather, and day-type variables as explanatory variables/drivers. Weather data and economic data and forecasts are procured from outside vendors. The model features simulation of historical weather patterns and regional diversities to develop a distribution of forecasts which are then used to produce monthly and seasonal forecasts across a range of weather conditions.

PJM significantly revised its load forecast model in 2015. The treatment of weather was restructured to provide more variable load response to weather across a wide range of conditions. Three variables (cooling, heating, and other) were added to account for trends in equipment/appliance saturation and efficiency, and distributed solar generation is now reflected in the historical load data used to estimate the models, with a separately-derived solar forecast used to adjust load forecasts.

**Energy efficiency and demand response.** All forecasts produced by PJM are reduced by forecasts of distributed solar generation. In addition, the recent PJM forecast enhancements include variables to account for energy efficiency effectively integrate energy efficiency into the forecast. In addition to this, PJM projects load management effects based on the market products acquired through PJM Capacity Auctions.

**Supply-side modeling.** Market efficiency simulations model existing in-service generation plus actively queued generation with an executed facilities service agreement or a signed interconnection service agreement, less planned generator deactivations that have given formal notification. The modeled generation generally provides enough capacity to meet PJM's installed reserve requirement through all study years. The total amount of behind-the-meter solar generation is forecasted separately from the load forecast model but is then incorporated into the load forecast to adjust the unrestricted load of each zone.

**Transmission system network representation.** During every planning cycle, PJM develops two power-flow cases to represent an “as-is” transmission topology and a projected “as-planned” topology for the RTEP year that is five years into the future. The “as-is” system topology is based on a summer peak case developed by the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group (MMWG). This power-flow case includes transmission upgrades expected to be in service during the upcoming summer (August 2016 for the current cycle). The “as-planned” topology for the 2016 RTEP cycle was derived from PJM’s 2020 RTEP base case with appropriate modifications to create a 2021 RTEP analysis model, which is used for baseline reliability studies.

**Environmental emission allowances.** PJM uses a commercially available database tool that includes generator fuel price forecasts. Forecasts for short-term gas and oil prices are derived from New York Mercantile Exchange future prices. Long-term forecasts for gas and oil and all coal price forecasts are obtained from commercially available databases. In addition, vendor-provided basis adders are applied to account for commodity transportation cost to each PJM zone. With the exception of gas, fuel prices within the databases have remained relatively stable from the 2014 base cases.

In the 2015 RTEP, the incremental cost of sulfur oxide (SO<sub>x</sub>) was set to zero. PJM unit carbon dioxide (CO<sub>2</sub>) emissions were modeled either as part of the national CO<sub>2</sub> program or, for Maryland and Delaware units, as part of the Regional Greenhouse Gas Initiative (RGGI) program. The emission prices for the national CO<sub>2</sub> program were set to zero for all study years. The RGGI program CO<sub>2</sub> emissions price was set to a non-zero value for all study years. The 2015 sensitivity case does not include any changes in emission allowance price assumptions.

**Regional modeling.** PJM models surrounding regions external to PJM’s active footprint when appropriate. Representation of these external regions includes multi-party transactions with commitment and dispatch hurdle rates defined between pools. In addition to actively dispatching some external regions, PJM sets up the market model to apply a set of user-defined scaling regions to balance load and generation within inactive areas. Fixed transactions are modeled to represent additional levels of interchange between the active areas and static areas. Table H - 1 reports selected modeling assumptions.

**Table H - 1. Selected Modeling Assumptions for All Study Years (2014, 2015, 2019, 2022, 2025, 2029)**

Variable - Unit	Value	Source
<b>Load – Summer Peak GW</b>	156 GW, 159 GW, 165 GW, 170 GW, 171 GW, 180 GW	
<b>Net Annual Energy TWh</b>	814 GW, 827 GW, 851 GW, 872 GW, 884 GW, 902 GW	
<b>Natural gas prices</b>	4.5 \$/mmBTU (2014) -8.5 \$/mmBTU	See footnote <sup>46</sup>
<b>CO<sub>2</sub> price</b>	0 \$/mmBTU (national), 4 \$/mmBTU (2014) – 16 \$/mmBTU	
<b>SO<sub>2</sub> price</b>	Unavailable	
<b>NO<sub>x</sub> price (\$/ton)</b>	38, 39, 41,45, 49, 53	

<sup>46</sup> See <http://www.pjm.com/~media/library/reports-notice/load-forecast/2017-load-forecast-report-data.ashx>.

## Acronyms and Abbreviations

B/C	benefit/cost
ERAG	Eastern Interconnection Reliability Assessment Group
FERC	Federal Energy Regulatory Commission
NERC	North American Electric Reliability Corporation
ERAG	Eastern Interconnection Reliability Assessment Group
MISO	Midcontinent Independent System Operator
MMWG	Multi-Regional Modeling Working Group
PJM	PJM Interconnection
RGGI	Regional Greenhouse Gas Initiative
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Operator
TEAC	Transmission Expansion Advisory Committee

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# Appendix I. South Carolina Regional Transmission Planning (SCRTP)

## Summary

The South Carolina Regional Transmission Planning (SCRTP) process provides a forum that is managed by the two transmission providers serving a large portion of the state of South Carolina to conduct regional transmission planning activities in compliance with FERC Order Nos. 890 and 1000. The evaluation of projects that might be selected for regional cost allocation involves comparing the expected cost of a qualified sponsor-proposed project to that of the local projects it might displace and the increased or decreased efficiencies of the combined, two transmission systems, including the estimated value of the reduction of real power losses.

## Background

SCRTP was formed in 2010, largely in response to FERC Order No. 890. Two transmission providers serving South Carolina participate in SCRTP: South Carolina Electric & Gas Company (SCE&G) and South Carolina Public Service Authority (Santee Cooper) (collectively, the Transmission Providers). SCRTP's Order No. 1000-compliant regional transmission planning process and cost allocation provisions became effective for the region in April 2013.

For Order No. 890 purposes, the principle focus of SCRTP transmission planning activities is to provide an open and transparent process for sharing transmission planning information and transmission plans with stakeholders. For Order No. 1000 purposes, the principal focus of SCRTP planning activities is to evaluate proposed regional transmission projects sponsored by non-incumbent developers and to evaluate recommendations for transmission needs driven by public policy requirements. To date, no projects have been proposed by non-incumbent developers for evaluation and no projects have been selected for regional cost allocation.

These and other transmission planning activities conducted by SCRTP are reported in SCRTP stakeholder group meetings held each quarter. Information presented at these meetings is posted on the SCRTP website. In addition, SCRTP releases planning studies which contain Critical Energy Infrastructure Information and these studies are accessible to only stakeholders who have signed a Non-disclosure and Confidentiality Agreement.

## Regional Transmission Planning

SCRTP conducts two regional planning activities annually. The first is a set of economic planning studies. The second is the FERC Order No.1000 process for selecting regional transmission projects that are more efficient or cost-effective than those contained in the plans of SCG&E or Santee Cooper. This latter process also includes the evaluation of transmission needs that might be driven by public policy requirements.<sup>47</sup>

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<sup>47</sup> SCRTP's interregional transmission coordination activities are not the focus of this report and are not discussed in this summary.

The annual economic planning studies evaluate the requirements associated with up to five stakeholder identified incremental transfers within the region and between the SCRTP region and other regions—such as the movement of 500 MW of power from one part of the state to another or the movement of even larger power transfers from and to areas outside the SCRTP footprint. The transfers are developed based on requests made by stakeholders. SCRTP conducts reliability and engineering analyses to determine the costs associated with the facility upgrades that would be required to reliably accommodate the transfer. The goal is to inform those interested in pursuing these transfers of the costs that would be involved.

The process for selecting transmission projects for regional cost allocation involves evaluating non-incumbent developer-sponsored projects in comparison to planned projects that are contained in the transmission plans of the two planning entities that comprise SCRTP. Regional transmission alternatives may be proposed by stakeholders, merchants, and qualified non-incumbent developers. By definition, a regional transmission alternative must provide benefits to the ratepayers of more than one transmission provider.

SCRTP evaluates proposed transmission alternatives to confirm that they will meet NERC and SERC (SERC Reliability Corporation) reliability planning criteria. It then evaluates how the expected cost of an alternative compares to the planned local transmission project that might be displaced, as well as the estimated value of the reduction of real power losses associated with the alternative. If an alternative is found to be more efficient or cost-effective, in accordance with the Transmission Providers' Order No. 1000 process, it would be selected for regional cost allocation.

SCRTP's open competitive process can be thought of as a sponsorship model. That is, if the entity proposing a regional transmission alternative is a qualified developer and if their alternative is found to be more efficient or more cost-effective, then they would be selected to develop the project and receive regional cost allocation for it.

SCRTP's assessment of transmission needs driven by public policy requirements involves soliciting proposals from stakeholders, which it then evaluates. In addition, Transmission Providers, stakeholders, and non-incumbent developers may propose solutions to meet identified needs. Stakeholders are provided an opportunity to provide their input in the development of solutions. Proposed solutions are evaluated in accordance with the SCRTP selection process (which is similar to that used to evaluate solutions addressing transmission needs driven by reliability or economics). If a transmission project submitted for cost allocation is selected, those cost will be allocated pursuant to the Transmission Providers' Order No. 1000 process.

A central consideration of SCRTP in evaluating stakeholder proposals for transmission needs driven by public policy requirements is the extent to which there are other bodies that have a primary or principal responsibility for ensuring that the policies are fulfilled—such as the state of South Carolina. SCRTP provides deference to the authorities of these bodies to determine whether their policies create needs for transmission driven by public policy requirements that SCRTP should evaluate for potential solutions

or that will instead be met through other means (e.g., through an integrated resource planning process led by the Public Service Commission of South Carolina).

### **Acronyms and Abbreviations**

FERC	Federal Energy Regulatory Commission
NERC	North American Electric Reliability Corporation
SCE&G	South Carolina Electric & Gas Company
SCRTP	South Carolina Regional Transmission Planning

### **References**

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## Appendix J. Southeastern Regional Transmission Planning (SERTP)

### Summary

The Southeastern Regional Transmission Planning (SERTP) process is managed by an association of transmission planning entities serving all or portions of the fourteen Central and Southeastern states of Alabama, Florida, Georgia, Indiana, Iowa, Kentucky, Mississippi, Missouri, North Carolina, Ohio, Oklahoma, South Carolina, Tennessee, and Virginia. SERTP's principal activity is to conduct regional transmission planning activities in compliance with Federal Energy Regulatory Commission (FERC) Order Nos. 890 and 1000. The evaluation of a potential regional transmission project that might be selected for regional cost allocation involves comparing the expected cost of a qualified developer-proposed project to that of the transmission projects it might displace, as well as cost savings associated with reductions in transmission losses.

### Background

SERTP was formed in 2007, largely in response to FERC Order No. 890. Participation in SERTP has grown over time and now is sponsored by 10 transmission planning entities. SERTP's Order No. 1000-compliant regional transmission planning process and cost allocation provisions became effective for SERTP in June 2014.

Prior to SERTP's formation, there were no precedents for regional cost allocation among the entities participating in SERTP. To date, SERTP has not selected any transmission projects for regional cost allocation.

### Regional Transmission Planning

SERTP conducts several regional transmission planning activities annually, including economic planning studies (selected by stakeholders), a regional transmission planning assessment, and an assessment of stakeholder-proposed transmission needs driven by public policy requirements.<sup>48</sup>

The economic planning studies evaluate the requirements associated with up to five hypothetical, incremental transfers into or out of the region—such as the movement of 500 MW of power from one sub-region or state to another. The transfers are developed based on requests made by stakeholders through the Regional Planning Stakeholder Group (RPSG). SERTP conducts reliability and engineering analyses to determine the costs associated with the facility upgrades that would be required to reliably accommodate the transfer. The goal is to inform those interested in these transfers of the costs that would be involved in pursuing them.

The annual SERTP regional transmission planning process begins with the combined, ten-year transmission expansion plans of SERTP sponsors. As part of this effort, SERTP will assess regional

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<sup>48</sup> SERTP's interregional transmission coordination activities are not the focus of this report and are not discussed in this summary.

alternatives to planned transmission projects contained in the individual plans of these sponsors. Regional alternatives may also be proposed for regional cost allocation by SERTP sponsors, stakeholders, and qualified developers. SERTP evaluates proposed alternatives and reports on how the expected cost of the alternatives compare to the planned transmission project(s) that would be displaced as well as cost savings associated with reductions in transmission losses. If such an alternative is found to be more efficient or cost-effective per the respective Open Access Transmission Tariffs (OATTs), it may be selected for regional cost allocation.

SERTP's means for selecting projects for regional cost allocation can be thought of as a sponsorship-type model. That is, if the entity proposing a regional alternative is a qualified developer and their alternative qualifies as a project that is eligible for cost allocation, and it is found to be more efficient or cost-effective, then they would be selected to develop and receive a regional cost allocation for the project. To date, no transmission project proposals have been submitted for regional cost allocation.

SERTP's assessment of transmission needs driven by public policy requirements involves reviewing proposals from stakeholders both for such needs and potential solutions to them. SERTP may conduct an analysis and develop transmission solutions to meet these needs. Such solutions would then be potentially subject to displacement by more efficient or cost-effective transmission projects that may be proposed by qualified developers or stakeholders for regional cost allocation. If a qualifying regional transmission project is selected, it would receive regional cost allocation.

In evaluating stakeholder proposals for transmission needs driven by public policy requirements, SERTP may consider the extent to which there are other bodies that have a primary or principal responsibility for ensuring that these policies are fulfilled (such as state Public Utility Commissions) and to what extent they have addressed these needs or whether SERTP should evaluate these needs for potential solutions.

## **Recent Transmission Planning Study**

This section summarizes the 2016 Regional Transmission Planning Analyses (SERTP 2016a).

### **Study objective**

The objective of the 2016 Regional Transmission Planning Analyses conducted by SERTP sponsors was to evaluate the extent to which the then-current regional transmission plan addressed transmission needs within the SERTP region. A focus of the analysis was to assess whether alternative transmission projects could meet these needs more efficiently and cost-effectively than those already included in the regional transmission plan. Transmission plans are shared with SERTP stakeholders at regular intervals during the year, and the frequent engagement with stakeholders allows for additional inputs into potential project alternatives.

## Study approach

The study process relies on regional powerflow models that are developed annually by SERTP. The models capture the current topology of transmission within the region, as well as planned upgrades over a ten year planning horizon. The inputs to and assumptions relied on by the models are developed based on load forecasts, generating resources, interface commitments, etc. that are provided by the Load Serving Entities in the SERTP region.

Staff of SERTP sponsors use the models to conduct reliability analyses, including voltage, stability and short circuit. The two main analyses consider: (1) facilities that operate at 100kV and above that are selected based on thermal and voltage rating criteria, and (2) contingency (N-1) analyses for all transmission facilities that operate at 100kV and above. The results of the analyses are generally reported for each Balancing Authority Area in the SERTP region.

The regional transmission analysis also includes an assessment that evaluates potentially more efficient or cost-effective alternative transmission projects as compared to those already included in the 2016 regional transmission plan. In 2016, the SERTP sponsors identified a list of nine potential transmission project alternatives.

In order to evaluate whether the transmission project alternatives were potentially more efficient or cost-effective alternative transmission projects in addressing regional transmission needs, the SERTP sponsors performed coordinated analysis using the corresponding regional models in the 2021 and 2026 timeframes. Specifically, each SERTP sponsor utilized its respective transmission planning criteria to evaluate whether/how the alternative transmission project: (1) addressed transmission needs already addressed by other transmission projects contained in the 2016 regional transmission plan; and/or (2) resulted in additional transmission constraints within the SERTP region.

## Findings

The 2016 Regional Transmission Plan (SERTP 2016a) analyzed transmission facilities in each of the nine balancing authorities within SERTP and found that none of them were constrained. It also found that none of the nine new potential transmission project alternatives evaluated was more efficient or cost-effective as compared to the transmission projects included in the 2016 Regional Transmission Plan.

## Metrics used

The study criteria by which the results of each planning study are evaluated are outlined in the NERC (North American Electric Reliability Corporation) Reliability Standards or individual sponsor criteria, i.e. voltage, thermal, stability and short circuit. SERTP's planning studies are initially performed using power flow analysis, using PSS/E, and monitor facilities in the SERTP region that operate at 100kV and above. Screening for potential constraints is based upon the thermal and voltage rating criteria applicable to each transmission facility.

## Acronyms and Abbreviations

FERC	Federal Energy Regulatory Commission
NERC	North American Electric Reliability Corporation
OATT	Open Access Transmission Tariff
RSPG	Regional Planning Stakeholder Group
SERTP	Southeastern Regional Transmission Planning

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## Appendix K. Southwest Power Pool (SPP)

### Summary

The Southwest Power Pool (SPP) operates the high-voltage power system, administers a centralized market for wholesale power, and conducts power system planning for all or portions of fourteen Midwest states (Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming).<sup>49</sup> SPP conducts planning studies that, among other things, lead to the development of seven types of transmission projects: balanced portfolio, generation interconnection, high priority, integrated transmission plan, transmission service, zonal reliability, and regional reliability. The economic evaluation of projects, in addition to cost, considers the potential impact of projects on economic congestion costs, overall system production costs, and capacity savings.

### Background

SPP was formed in 1941 to coordinate operations for eleven regional utilities, initially in support of production efforts during World War II. SPP became a regional reliability council as part of the formation of the North American Electric Reliability Corporation (NERC) in 1968. FERC approved SPP as a regional transmission organization (RTO) in 2004. SPP began operating an integrated day-ahead and real-time balancing market in 2014.

Integrated, region-wide planning for transmission, including regional cost allocation for projects, began in 2004 following FERC's approval of SPP as an RTO. The first transmission projects to address economic congestion in the region and have their costs allocated regionally were approved in 2009 and are called the Balanced Portfolio projects. A second group of projects, also with regional cost allocation, was approved in 2010 and are called the Priority Projects. SPP then began its Integrated Transmission Planning (ITP) process in which all approved projects greater than 300kV will have their costs allocated regionally and those between 100kV and 300kV will have one-third of their costs allocated regionally.

FERC Order No. 1000 has resulted in two major changes to SPP's transmission planning processes. First, SPP now provides for a competitive solicitation process to select among non-incumbent and incumbent transmission developers through an open competitive process. The process awards incentive points for those transmission planning proposals selected as approved projects. Second, SPP has now formalized arrangements for interregional transmission coordination with its principal neighbors, the Midcontinent Independent System Operator (MISO) and Southeastern Regional Transmission Planning Process (SERTP).<sup>50</sup> A third major change brought about by FERC Order No. 1000—transmission needs driven by public policy requirements—has not led to major changes to SPP's planning processes because those

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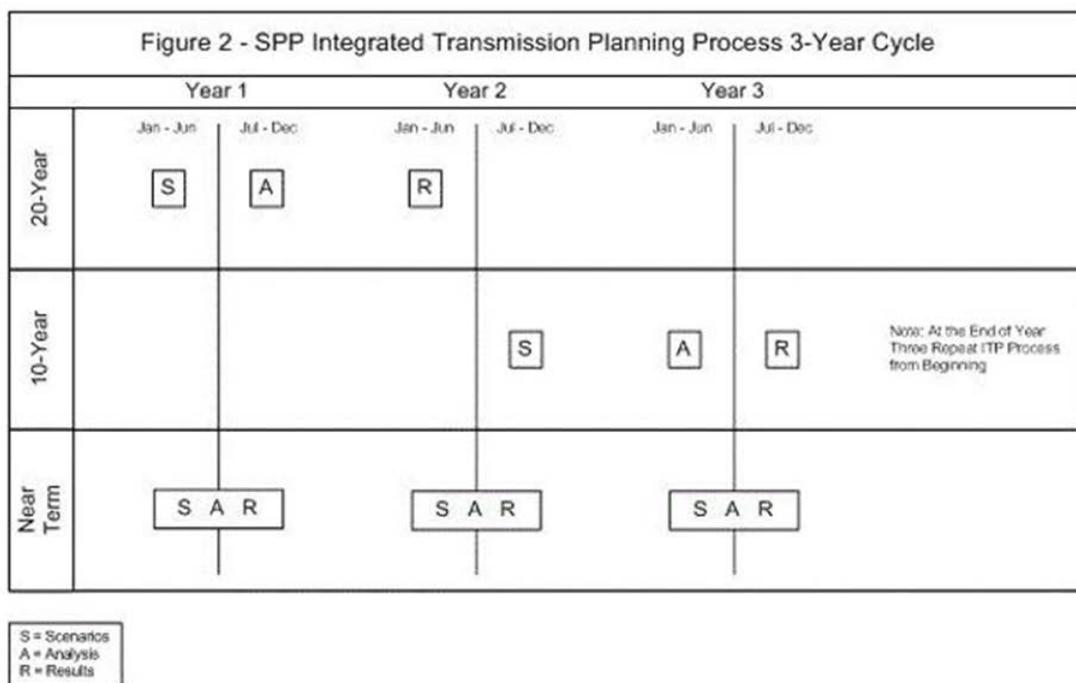
<sup>49</sup> SPP's footprint varies because SPP provides several different transmission-related functions and the members participating in each function vary. For the purposes of transmission planning with respect to FERC Order No. 1000, SPP's footprint consists of all or portions of 12 of these states (those listed other than Colorado and Wyoming).

<sup>50</sup> SPP's interregional transmission coordination activities are not the focus of this report and are not discussed in this summary.

considerations have always been included in its processes. SPP's Order No. 1000-compliant regional transmission planning process and cost allocation provisions became effective for the region in March 2014.

### Regional Transmission Planning

The three major planning assessments conducted as part of the ITP process (near-term, ten-year, and 20-year) are conducted over a three-year cycle. See Figure K - 1. SPP publishes a summary of the assessments, a list of all approved projects, and the status of past approved projects annually in the SPP Transmission Expansion Plan.



**Figure K - 1. Integrated Transmission Planning Process**

Source: SPP (2014). 2015 ITP10 Scope.

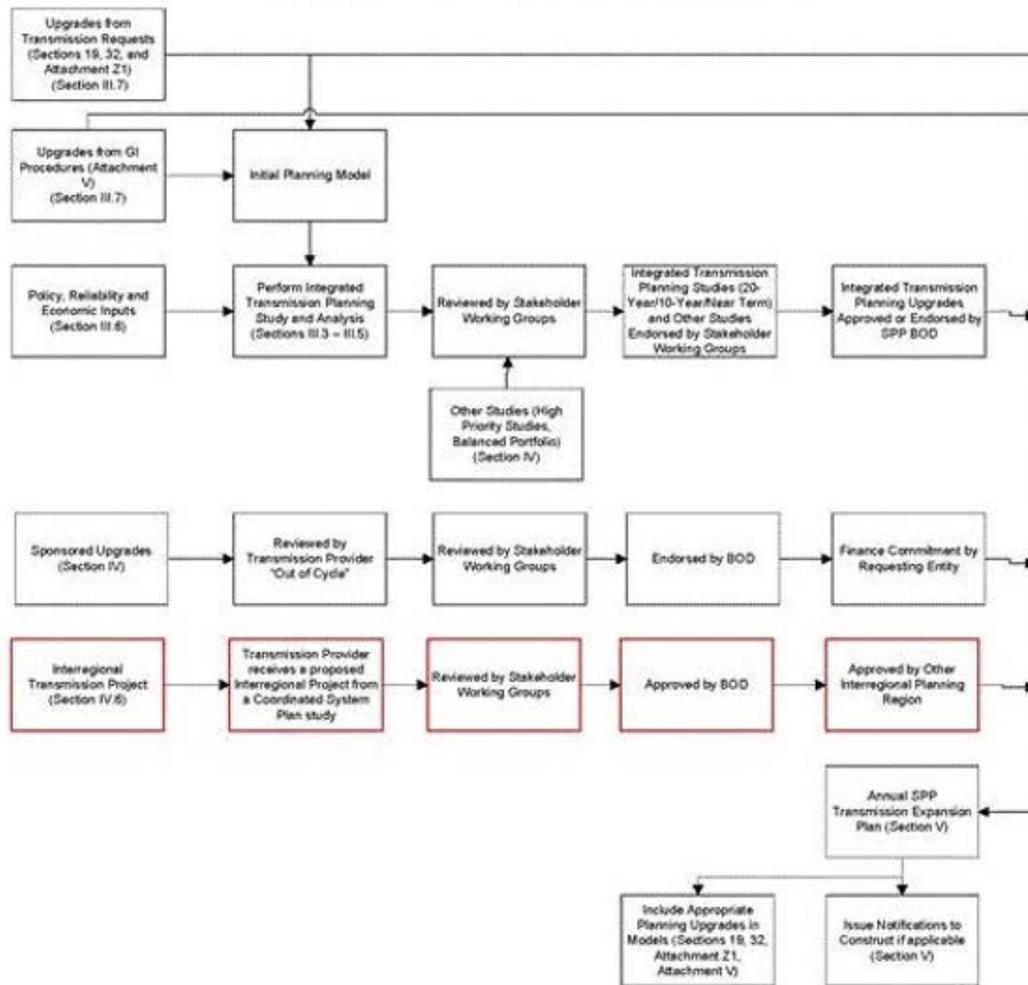
The first assessment (ITP20) looks ahead 20 years and is focused exclusively on planning for the highest voltage lines in SPP (345kV and above). Its purpose is to design a backbone transmission system for the region considering reliability, economic, and public policy drivers. The projects identified in ITP20 are not expected to lead to projects approved for construction. The plans are, therefore, conceptual in this sense. Nevertheless, the projects identified are used to inform the other assessments (notably the subsequent ITP10 study). ITP20 is conducted over the first 18-month phase of the three-year planning cycle.

The second assessment (ITP10) looks ahead ten years and is conducted over the second eighteen-month phase of the three-year planning cycle. The scope of planning is expanded to consider all solutions 100kV and above. Inputs to the study come from both the preceding ITP20 study and from reliability and economic analysis of the transmission system (starting at 69kV).

The third assessment (ITP near-term, or ITPNT) looks ahead four to six years and is conducted annually in each year of the three-year planning cycles. The focus of the ITPNT is to address reliability issues that will require transmission solutions.

Projects approved at the conclusion of any ITP10 or ITPNT for which a financial commitment must be made within the next four years will result in issuance of Notifications to Construct (NTCs) to the appropriate transmission developer.

Both ITP20 and ITP10 rely on a common base of information, engineering tools, and sequence of planning process. See Figure 2. Both rely on scenario analyses in order to develop a robust plan that takes into account uncertainty in future conditions. ITP20 relies on a broad range of future scenarios consistent with the longer time horizon it considers. ITP10 relies on a narrower range of scenarios and judgment is exercised in placing greater emphasis on the results from what are deemed to be the most plausible scenarios.



**Figure K - 2. ITP10 and ITP20 Transmission Planning Processes**

Source: SPP (2014). 2015 ITP10 Scope.

Each future scenario requires a generation expansion (and retirement) plan and the hypothetical siting of new generation within SPP. Production cost modeling tools are then used to identify the locations and to assess the magnitude of constraints within the system. In addition, reliability analyses are conducted.<sup>51</sup> Next, as one of the FERC Order No. 1000–directed enhancements, stakeholders are provided an opportunity to propose solutions (both transmission and non-transmission) that SPP will evaluate in conjunction with solutions proposed by SPP staff.

In evaluating proposed solutions, SPP considers ten benefit metrics:

1. Adjusted production cost savings
2. Reduction of emission rates (evaluated by using allowance prices to add to production cost savings)
3. Savings due to lower ancillary service needs (evaluated by changes in the production cost of acquiring these services)
4. Avoided or delayed reliability projects (evaluated using the costs avoided by the avoided or delayed project)
5. Capacity cost savings due to reduced on-peak transmission losses (evaluated by applying the cost of new entry to the reduction in installed capacity requirements)
6. Assumed benefit of mandated reliability projects (evaluated by setting this benefit equal to the cost of a project required to meet reliability standards)
7. Public policy benefits (also evaluated by setting this benefit equal to the cost of a project to meet a public policy)
8. Increased wheeling through and out revenues (evaluated using a historical average wheeling charge)
9. Marginal energy losses benefit (evaluated by post-processing production cost results on a zonal basis)
10. Mitigation of transmission outage costs (evaluated by modifying production cost modeling to reflect a level of transmission system outage consistent with historical records)

Transmission solutions that: a) are found via the net benefits calculated using these metrics to be more efficient or more cost-effective than alternatives, b) are approved for construction by the SPP Board of Directors, and c) are deemed to be competitive upgrades are then placed into an RFP process to select a developer whose project costs will be allocated in accordance with the SPP regional cost allocation process.

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<sup>51</sup> Note that SPP is not the NERC-registered transmission planner for all the transmission systems in its footprint.

## Recent Transmission Planning Study

This section summarizes information from a recent SPP transmission planning study carried out as part of the 2015 ITP process: The 2015 ITP10.

### Approach

For the purpose of this study, two future scenarios were defined to address uncertain system conditions over the ten-year horizon of the analysis: a business-as-usual (BAU) future, and a decreased baseload capacity future, which is based on the BAU future but assumes a decrease in existing baseload generation capacity.

Major steps in 2015 ITP10 planning process included:

- Conducting security-constrained unit commitment and economic dispatch analyses for a full study year, for the identified scenarios, based on the transmission constraints defined for the system. The simulation's results reveal which constraints caused the most congestion and the additional cost of dispatching around those constraints.
- Identifying the 25 highest congested elements in the SPP system. The congestion metric used to rank the constraints is the constraint's average shadow price multiplied by the number of hours during which the constraint is binding in the study year.
- Developing potential project solutions and evaluating their impacts on congestion and reliability needs.

Economic evaluation of all proposed economic projects entails calculating the adjusted production cost (APC) for each project in the SPP footprint, with and without the project for all hours of the study year (e.g. for the 2015 ITP study, the study year is 2024).

The evaluation process takes place in several steps/phases:

1. The first phase evaluates projects for inclusion or exclusion from the production-cost model, using a screening test based on annual APC benefit calculations, and considering the individual project's performance in the base case, with the respect to the impact of such project on system congestion reduction/increase.
2. The second phase further evaluates the subset of projects that passed the first screening, in concert with other potential projects, and based on their gross/net APC benefits. In this phase, reliability, public policy and/or economic projects may be grouped together if such projects encompass multiple benefit categories.
3. The third phase consolidates the grouping performed in the previous phase, based on the projects' one-year benefit/cost (B/C) ratio and a different threshold for each future/scenario under study.

4. The last phase consolidates the portfolios that have been defined for each future into a single final portfolio, to be analyzed across both futures, based on reliability, economic, and policy criteria separately. For example, if the portfolio served a reliability need, then it is evaluated in a future-year power-flow case. If the portfolio served an economic need, it is incorporated into a production-cost simulation for a specific future scenario, and a B/C analysis is run over a 40-year study period; the APC values produced by the production-cost study are then interpolated over the time horizon, and other metrics are considered for evaluating a broad range of economic impacts of the portfolio—such as reduction of emission rates, savings from reduced ancillary services’ needs, and production costs.

In addition, SPP also performs sensitivity analyses on the consolidated portfolio of projects, based on assumptions and considerations made by stakeholders on potential changes to the input variables that can have impacts on the simulation results. Examples of such variables are natural gas prices, demand growth rates, and inclusion of other transmission upgrades.

### Findings

The results of the 2015 ITP10 process defined a consolidated portfolio of 32 network upgrades, of which, 26 projects were evaluated in the Business as Usual future scenario, and the remaining 6 were assessed in the F2 future scenario. Of these 29 projects are reliability projects, one is an economic project, and two are economic and reliability projects.

The overall cost of this portfolio of project is \$273 million and net present value of the benefits is about \$334 million. These network upgrades are expected to provide approximately \$1.4 billion net benefits over their operating life under the BAU scenario.

### Metrics

The evaluation conducted in 2015 ITP10 required an economic project to have a minimum one-year B/C ratio of 0.9 or greater. This B/C target was selected because the benefit is expected to increase over a project’s assumed 40-year lifespan. Benefits are measured as the difference in the APC, with and without the potential economic project.

Table K - 1 lists the adjusted production cost-based economic metrics used in the 2015 ITP10 to evaluate individual projects.

**Table K - 1. 2015 ITP10 Economic Metrics**

Metric	Description	Notes
<b>Adjusted Production Costs (\$)</b>	Primary metric to evaluate potential changes to transmission system and addition of new types of resources (not limited only to transmission projects)	This metric is based on the summation of production costs, purchases and sales of electricity
<b>Sales (\$)</b>	Component of the APC metric	This metric is based on the multiplication of the sales of electricity and the Generation LMP (\$/MWh)
<b>Purchases (\$)</b>	Component of the APC metric	This metric is based on purchases of electricity by hour and by zone, multiplied by the LMP paid by the zonal/hub load

### Modeling and Selected Assumptions

**Load.** SPP members and non-members within the SPP footprint, as well as from areas outside, provided data on load forecasts for the years 2019 and 2024. SPP queried its members through the Model Development Working Group (MDWG) for applicable load forecasts to use in each of the zones of the modeling footprint. The base model also included additional load expected in the SPP region, which, in turn, included a 50/50 forecast from the High-Priority Incremental Load Study (HPILS). SPP requests load forecasts outside of its footprint from tier-1 neighbors. If data are not received, publicly available data are then utilized. If data are unavailable, the representation for the load expected in the study timeframe is defined based on the publicly available information on projected load growth.

**Supply-side modeling.** An ITP10 generator review was conducted with stakeholder input. The information includes maximum capacities, ownership, retirements, and other operating characteristics of all generators in SPP. The existing generation in the SPP region was updated with this information before development of the resource plan. New generation information and siting were developed based on a capacity margin requirement for each load-serving member within SPP's footprint.

Renewable generation information was gathered through a policy survey in which members reported their renewables mandates, goals, and other types of renewable additions by 2024. Additional renewable generation is added to the generation defined in the policy survey in case existing generation is not enough to meet projected load.

**Transmission System Network representation.** Each future scenario has its own powerflow model. Powerflow models are required for both the economic and reliability assessments. The starting point of these powerflow models is the latest MDWG information from Model on Demand, which includes the current projects from the latest SPP Transmission Expansion Plan report. These powerflow models also serve as an input into the economic modeling program to develop a market-based economic dispatch for the system.

**Environmental Emission Allowances.** Emission price forecasts for sulfur dioxide (SO<sub>2</sub>) and nitrogen

oxides (NO<sub>x</sub>) for the study years were based on Ventyx simulation-ready data, specifically the 2012 Spring Reference Case released in May 2012. No emission price was utilized for CO<sub>2</sub>.

**Regional modeling.** Energy markets were modeled for other regions within the Eastern Interconnection. Notably, Associated Electric Cooperatives Inc. (AECI), Mid-Continent Area Power Pool (MAPP), Tennessee Valley Authority (TVA), and Midcontinent Independent System Operator (MISO) were modeled as external energy markets. Entergy and Cleco were modeled within the MISO energy market. For the two modeled future scenarios, resource plans were also developed for external regions. Each region was assessed to determine its capacity shortfall, and natural-gas combined-cycle and combustion turbine units were added so that each region met its own capacity margin. New units were interconnected to lines with high transfer capacity. Units were added in AECI, TVA, MISO, WAPA (Western Area Power Administration), and Saskatchewan Power (SASK). SPP staff contacted these entities to obtain resource plans for 2019 and 2024. The MISO resource plan was based on the MISO Transmission Expansion Plan (known as “MTEP13”) (MISO 2013). SPP Staff calculated the resources needed for Entergy and Cleco because the MTEP13 did not include these regions in its calculations.

ITP studies have historically used an \$8/MWh commitment hurdle rate and a \$5/MWh dispatch rate for all interfaces to and from SPP. For the 2015 ITP study, custom hurdle rates were defined based on an assessment of historical tie-line flows between SPP and its tier-1 pools (MISO, MAPP, and SERC). Hurdle rates between SPP and external regions outside of tier-1 pools were set to values applied in the MTEP12 (MISO 2012) study instead.

**Table K - 2. Selected Modeling Assumptions (Study Years 2019 and 2024)**

Variable - Unit	Value	Source
Load – Summer Peak	60.8 GW- 64.4 GW	
Net Annual Energy	302 TWh- 323 TWh	
Coincident Peak Load	57 GW- 61 GW	
Peak Demand Growth Rate	1.16% (from 2019 to 2024)	2015 ITP
Natural gas prices	Ventyx data	
CO <sub>2</sub> price	Not modeled	
SO <sub>x</sub> price	Ventyx - 2012 Spring Reference Case released in May 2012	
NO <sub>x</sub> price		

### Acronyms and Abbreviations

AECI	Associated Electric Cooperatives Inc.
APC	adjusted production cost
B/C	benefit/cost
BAU	business as usual
FERC	Federal Energy Regulatory Commission
HPILS	High-Priority Incremental Load Study

ITP	Integrated Transmission Planning
ITPNT	Integrated Transmission Planning, Near-Term
LMP	Locational Marginal Price
MAPP	Mid-Continent Area Power Pool
MDWG	Model Development Working Group
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NTC	Notification to Construct
RTO	regional transmission organization
SERTP	Southeastern Regional Transmission Planning Process
SPP	Southwest Power Pool
TVA	Tennessee Valley Authority

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## Appendix L. WestConnect

### Summary

WestConnect is an association of stakeholders and transmission owners (i.e., those entities having signed a Planning Participation Agreement) serving portions of the Western states of Arizona, California, Colorado, Nebraska, Nevada, New Mexico, South Dakota, Texas, and Wyoming. WestConnect’s principal focus is conducting regional transmission planning activities in compliance with FERC Order No. 1000 that may lead to the selection of projects for regional cost allocation. The economic evaluation of transmission projects involves, among other things, application of production cost models to estimate regional economic benefits.

### Background

WestConnect was formed through a memorandum of understanding in 2004 involving participants in three Western state sub-regional transmission planning entities: Colorado Coordinated Planning Group; Sierra Subregional Planning Group; and Southwest Area Transmission. WestConnect members have collaborated formally on regional transmission planning activities since 2007 in response to FERC Order No. 890. WestConnect further adapted and modified its planning processes in response to FERC Order No. 1000. Responsibilities for preparing a regional transmission plan that complies with FERC Order No. 1000 are administered by WestConnect’s Planning Management Committee (PMC). WestConnect’s Order No. 1000-compliant regional transmission planning process and cost allocation provisions became effective for the region in January 2015.<sup>52</sup>

The PMC oversees the development and approval of a regional transmission plan that is developed biennially. The sole purpose of the plan is to assess regional needs, driven by reliability, economic, or public policy considerations, that might be met more efficiently or cost-effectively with a regional solution. If such a solution is identified, and selected by the PMC for regional cost allocation, the PMC oversees an open competitive process to select a developer who is eligible to utilize the regional allocation method for the costs of the project.

WestConnect’s process for selecting transmission projects for regional cost allocation is a “competitive bidding” model. This is because the proposer of a transmission solution seeking regional cost allocation—even if their solution is selected—is required to compete in (and be selected in) WestConnect’s open competitive process in order to be awarded the opportunity to use the regional cost allocation method for the transmission project that they have proposed. WestConnect may make findings that a transmission project is more efficient or cost-effective compared to alternatives. However, if the developer of such a project does not seek regional cost allocation, WestConnect does not conduct an open competitive process to select a developer.

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<sup>52</sup> WestConnect’s interregional transmission coordination activities are not the focus of this report and are not discussed in this summary.

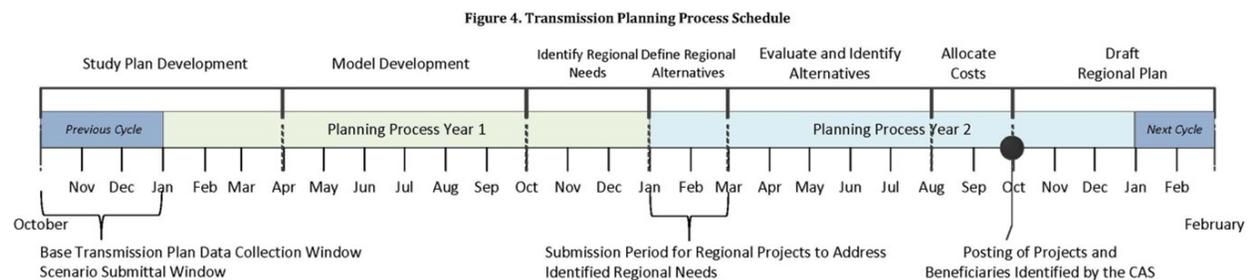
Prior to WestConnect’s formation, there was no precedent for regional cost allocation among the entities participating in WestConnect. To date, WestConnect has not selected a transmission project for regional cost allocation.

## Regional Transmission Planning

WestConnect’s transmission planning process for selecting regional projects is spread over a two-year period. See Figure L - 1. The starting point for the process is the transmission plans of the WestConnect transmission owners and the transmission needs driven by public policy requirements, all of which are used to develop a study plan that identifies regional transmission needs.

The majority of the first year of the process involves the preparation of WestConnect-wide system reliability and economic planning models for use in assessing regional transmission needs (and in the second year, evaluating the impacts of proposed regional solutions). The first year culminates with the identification of regional needs. The beginning of the second year involves an open process to receive proposals for regional solutions to meet any identified needs.<sup>53</sup> Both transmission and non-transmission alternatives may be proposed. The remainder of the second year consists of study work to evaluate the proposals to select more efficient or cost-effective solutions to meet regional needs.

If a project is determined to be more efficient or cost-effective solution and the proposer requests, WestConnect will initiate the process to establish a regional allocation of the project’s costs.



**Figure L - 1. WestConnect Transmission Planning Process Schedule**

Source: WestConnect (2016). *WestConnect Regional Planning Process Business Practice Manual, Version 1.0.*

The vetting processes for identifying potential regional reliability needs involves conducting reliability analysis for the combined and integrated model of the individual systems of the WestConnect transmission owners. North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability criteria violations affecting a single member’s system are referred back to the owner of the system to address. Violations affecting more than one member system may be candidates for a regional need. Similarly, the vetting process for identifying regional economic needs involves conducting production-cost simulation studies to identify areas of persistent

<sup>53</sup> To date, WestConnect has not yet, in fact, identified any regional transmission needs that remain after consideration of the extent to which the combined plans of the existing transmission owners have already addressed them.

or high cost congestion. The vetting process for identifying potential regional transmission needs driven by public policy requirements is driven by stakeholder input. Ultimately, the vetting processes result in a recommendation by the Planning Subcommittee to the PMC as to whether there are regional needs for transmission.

The evaluation of proposed transmission solutions submitted to meet identified regional transmission needs involves demonstrating that the solution meets the technical requirements of regional need and is more efficient or more cost-effective than other alternatives, including any local projects the regional solution might displace or augment. The PMC seeks to identify solutions for selection in the regional transmission plan for all identified regional needs.

For regional reliability, WestConnect measures reliability benefits based on avoided costs, where a transmission owner's share of the reliability benefits are calculated based on the cost of its local transmission facilities that would otherwise have to be built to comply with the NERC Transmission Planning Standards during the planning horizon. For public policy projects, WestConnect measures benefits by calculating the proportion of megawatts of public policy resources enabled by the proposed project for a given beneficiary compared to the total megawatts of public policy resources enabled by the project and multiplies the resulting proportion by the total cost of the project. For regional economic solutions being evaluated for cost allocation eligibility, the production cost savings are also considered. Specifically, net benefits—including production cost savings—must be greater than 1.0 for each of all reasonable scenarios and equal to or greater than 1.25, on average, taken together in order for a regional economic solution seeking cost allocation to be selected for regional cost allocation.

Regional transmission planning is an evolving activity for WestConnect. The processes for evaluating the benefits of potential regional solutions, are in their infancy and have yet to be exercised.

## Acronyms and Abbreviations

FERC	Federal Energy Regulatory Commission
NERC	North American Electric Reliability Corporation
PMC	Planning Management Committee
WECC	Western Electricity Coordinating Council

## References

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