A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations

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Columbia, Maryland

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

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February 2011

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NATIONAL RENEWABLE ENERGY LABORATORY

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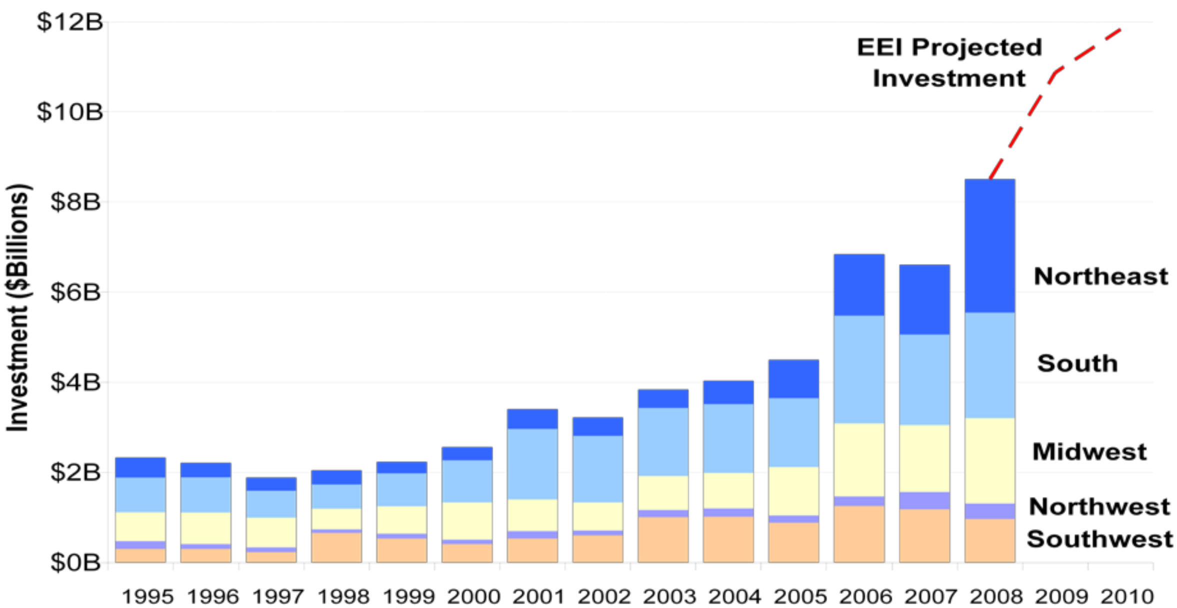
I. Executive Summary

After years of little to modest growth in transmission investment, the United States is experiencing an increase in investment in new transmission facilities. The Brattle Group reports that transmission investment in 2008 is quadruple that of average transmission investment levels in the 1990s, and projects annual transmission investment levels of $10 billion going forward.[1] The North American Electric Reliability Corporation (NERC) expects that transmission lines 100 kV and above will increase by 31,400 circuit miles, or about 8% by 2018.[2] In addition, the Brattle Group found that there is more than $120 billion worth of planned and conceptual transmission projects, although some are duplicative, and some of these will not go forward because of permitting and financing difficulties, among other reasons.[3]

Figure 1.
Brattle Group Estimates of Annual Transmission Net Plant Additions By Investor-Owned Utilities, 1995-2008



Source: Johannes Pfeifenberger, Peter Fox-Penner, and Delphine Hou, *Transmission Investment Needs and Cost Allocation: New Challenges and Models*, The Brattle Group presentation to the Federal Energy Regulatory Commission, December 1, 2009, p.2, http://www.brattle.com/_documents/UploadLibrary/Upload823.pdf.

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[1] Johannes Pfeifenberger, Peter Fox-Penner, and Delphine Hou, *Transmission Investment Needs and Cost Allocation: New Challenges and Models*, The Brattle Group presentation to the Federal Energy Regulatory Commission, December 1, 2009, http://www.brattle.com/_documents/UploadLibrary/Upload823.pdf.
[2] North American Electric Reliability Corporation, *2009 Long-Term Reliability Assessment: 2009-2018,* October 2009, http://www.nerc.com/files/2009_LTRA.pdf.
[3] Johannes Pfeifenberger, Peter Fox-Penner, and Delphine Hou, *Transmission Investment Needs and Cost Allocation: New Challenges and Models*, The Brattle Group presentation to the Federal Energy Regulatory Commission, December 1, 2009, http://www.brattle.com/_documents/UploadLibrary/Upload823.pdf.

Transmission cost allocation is commonly cited as a key issue in determining whether new transmission is built or not. Transmission cost allocation can be particularly contentious for multi-state transmission projects that cross more than one state, as the benefits of the proposed project may accrue unevenly to market participants. The difficulties in assigning transmission costs over a multi-state region were highlighted by the U.S. Seventh Circuit Court of Appeals decision in 2009 that remanded to the Federal Energy Regulatory Commission (FERC) the order that authorized PJM to recover the costs of new transmission facilities over 500 kV from all transmission customers in PJM. The case originated in part by the Illinois and Ohio state utility regulatory commissions objecting to paying for transmission facilities that are likely to be of more benefit to customers in eastern PJM. The Court stated that FERC had to better document how all transmission customers would benefit from the new transmission if all customers had to share in the cost.[4]

Several Regional Transmission Organizations (RTOs) have experimented with innovative transmission cost allocation strategies, and that is the primary focus of this report. Table 1 presents transmission cost allocation methodologies for reliability transmission projects, generation interconnection, and economic transmission projects for all RTOs.

[4] U.S. Court of Appeals for the Seventh Circuit, *Illinois Commerce Commission, et al. v. FERC, Nos. 08-1306, et al.* (7th Cir., Aug. 6, 2009), http://www.ferc.gov/legal/court-cases/opinions/2009/PT1FG750-opinion.pdf.

Table 1: RTO Transmission Cost Allocation for Reliability and Economic Transmission Projects

	CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	SPP
Reliability Upgrades	Participating transmission owners finance reliability upgrades and are repaid through Transmission Access Charges (TAC) assessed to CAISO grid users. Costs of upgrades ≥200 kV allocated to load on a MWh basis. Costs of merchant transmission facilities are allocated to the project sponsor, which may receive repayment through the TAC or congestion revenue rights.	ERCOT conducts a system-wide assessment and the cost allocation is the same for both reliability and economic projects. Costs allocated across all loads based on share of summer peak demand.	Reliability Upgrades included in ISO-NE Regional System Plan as needed to ensure reliability. Regional Benefit Upgrades are 115 kV and above; costs allocated to load based on zonal monthly coincident peak loads. Localized costs excluded from the regional allocation- those costs allocated only to the zone in which the localized costs were incurred. Local Benefit Upgrades are 115 kV and below; costs allocated locally to the zone.	Baseline Reliability Projects include upgrades where costs >$5 million or are 5% or more of the Transmission Owner's net plant. 345 kV or above - costs allocated 20% regionally on a postage stamp basis, 80% sub-regionally based on electrical proximity using Line Outage Distribution Factor (LODF) analysis. 100 kV to 344 kV – costs allocated 100% sub-regionally to pricing zones based on LODF analysis. PJM/ Midwest ISO cross-border allocation based on each RTO's contribution to the constraint that required the need for the upgrade; then within each RTO, done as per the RTO's respective methods. Have Proposed Multi-Value Projects category to FERC to support policy requirements and provide economic and reliability benefits.	Reliability planning identified by the NYISO Comprehensive Reliability Planning Process. While market-based solutions are preferred, if a regulated backstop solution is needed it is paid for on a beneficiary-pays basis. Primary beneficiaries – zones identified as those contributing to the reliability violation that the project will alleviate. Costs allocated to zones based on contribution to violation and to load serving entities (LSEs) within each zone on a load ratio share (MWh) basis.	Reliability Upgrades included in the Regional Transmission Expansion Plan (RTEP): Backbone Facilities: ≥ 500 kV, costs allocated 100% to load based on each zone's share of zonal non-coincident peak load; < 500 kV and cost < $5 million – are allocated to zone; cost ≥$5 million – direct beneficiaries identified and allocated costs. The cost allocation method for facilities ≥ 500 kV is currently under court-ordered review in FERC Docket No. EL05-121-006.PJM/ Midwest ISO cross-border allocation based on each RTO's contribution to the constraint that required the need for the upgrade; then within each RTO, done as per the RTO's respective methods.	Effective June 19, 2010, the Highway/Byway cost allocation system will apply to new transmission facilities identified as Base Plan Upgrades (BPU). BPU's include both reliability and economic projects approved by the SPP Board of Directors, including priority EHV projects and projects arising from SPP's proposed Integrated Transmission Planning (ITP) process. Highway: ≥300kV. All costs allocated regionally. Byway: < 300 kV. All costs zonal for projects <100 kV; for projects above 100 kV and below 300 kV, 1/3 allocated regionally and 2/3 zonal. Zonal allocations determined according to the SPP pricing zones.

	CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	SPP
Generator Interconnection Upgrades	Studies and direct interconnection costs are funded by the interconnection customer. Upgrade costs are funded by the interconnection customer subject to reimbursement by the participating transmission owner within 5 years. The participating transmission owner is repaid through the TAC, which is allocated to load on a MWh basis. Separate category for Location Constrained Resource Interconnection Facilities (LCRI) in designated areas. Costs are recovered through the TAC until generators come on-line, after which generators pay a pro rata share.	Costs allocated to the transmission service provider.	Costs of network upgrades are allocated to the generator. If ISO-NE determines the upgrade provides system-wide benefits, then costs are allocated in the same manner as ISO-NE's Reliability Upgrades.	Generators required to pay 100% of interconnection costs to lines smaller than 345 kV, and 90% of network upgrades for lines 345 kV or greater. The remaining 10% will be recovered system-wide. Separate category for projects interconnecting to American Transmission Company LLC, International Transmission Company, Michigan Electric Transmission Company, LLC, or ITC Midwest LLC: interconnection customer is fully refunded for their upgrade costs from the host transmission owner.	For Energy Resource Interconnection Service, developer is responsible for the cost of the new interconnection facilities not identified in the NYISO's Annual Transmission Reliability Assessment. For Capacity Resource Interconnection Service, the total cost of the upgrades for all the projects in a Class Year will be allocated among the projects based on the pro rata of each Class Year project on the required transmission system upgrades. In both cases, the developer is fully responsible for all attachment facilities.	The costs of interconnection in PJM are allocated in full to generators according to their projected system impact as determined through a study process.	Generator Interconnection Network Upgrades are direct assigned to Interconnection Customer at 100% of cost. Interconnection customer's contribution towards Network Upgrades are eligible for revenue credits.

	CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	SPP
Economic Upgrades	Economic Upgrades identified through the planning process are financed in the same manner as Reliability Upgrades.	ERCOT conducts a system-wide assessment and the cost allocation is the same for both reliability and economic projects. Costs allocated across all loads based on share of summer peak demand.	Market Efficiency Transmission Upgrades can be included in the ISO-NE Regional System Plan (RSP) if evaluated as beneficial to reducing bulk power system costs – if included in the RSP as a planned project, costs allocated same as for reliability upgrades. If not, costs allocated to project sponsors.	Regionally Beneficial Projects 345 kV or higher and costing over $5 million can qualify as an economic upgrade if it meets or exceeds cost/benefit test that increases linearly over the transmission planning period. Costs allocated 20% regionally on a postage-stamp basis, 80% to the three Transmission Provider Planning sub-regions (West, Central, East) as determined by congestion-based metrics (beneficiary analysis, 70% based on production cost benefits , 30% based on expected LMP-based load benefits. Analysis determines each sub-region's benefit from the upgrade, and costs recovered on a postage stamp basis within each). If a project can be designated as both a Regionally Beneficial Project and a Baseline Reliability Project, costs are allocated as a Regionally Beneficial Project.	To be eligible for this allocation, the projected benefit of the project (measured as the savings in statewide production cost with and without the proposed project) must exceed the estimated cost, as measured over the first ten years from the proposed commercial operation date. Total capital cost must exceed $25 million, and a super-majority of 80% or greater of the identified beneficiaries are required to approve the project. For each load zone that would benefit from a proposed project, costs are allocated based on the zonal share of total LMP energy savings. Within zones, costs allocated by each LSE's MWh share of total energy.	Costs of Economic Upgrade enhancements to reliability-based projects included in RTEP that reduce cost of meeting load are allocated the same way as reliability upgrades. For projects that are <500 KV and accelerate completion of an approved reliability project, cost allocation assigned to zones based on the reduction in LMP payments if there is at least 10% difference between this method and the method for reliability projects. For new economic transmission that is <500 KV, costs allocated to zones which have a projected decrease in load energy payments and is based on each zone's pro rata share of the change in load energy payment.	Priority EHV projects have been designated BPU and will be paid regionally through the Highway/Byway methodology. Projects arising through the ITP will be allocated according to Highway/Byway. ITP will integrate both reliability and economic study systems and will include an annual reliability assessment, a triennial 10-year midterm assessment, and a triennial 20-year long-term assessment. (Note: as of June 2010, SPP's ITP FERC filing was still pending.)

In addition to the above examples, the Midwest Independent Transmission System Operator (Midwest ISO) received FERC approval in December 2010 for a revised transmission cost allocation methodology that includes allocating the costs of "multi-value projects." The Midwest ISO would assign costs of such transmission projects to customers across the Midwest ISO. Among other purposes, multi-value projects are intended to support energy policy requirements. To be considered a multi-value project, the transmission project must be developed through the Midwest ISO's transmission expansion process, meet a benefit-to-cost ratio of 1.0 or higher, and address at least one transmission issue with a projected violation of a NERC or regional reliability standard.[5]

While this report primarily focuses on transmission cost allocation at RTOs, this is not to suggest that transmission development is only taking place among RTOs. The Subregional Planning Group (SPG) Coordination Group (SCG), formed to assist the Western Electricity Coordinating Council's (WECC) interconnection-wide transmission planning, determined there were 30 projects they determined as "foundational transmission projects" in that there is a high probability of these projects becoming operational within the next 10 years. The SCG also found another 30 potential transmission projects that are also under consideration. While not all of these transmission projects will come to fruition, the amount of transmission activity in the West is noteworthy.[6] Separately, WECC, the Western Governors' Association, and the Western Interstate Energy Board are working with stakeholders as part of the Regional Transmission Expansion Project to determine transmission requirements under several potential energy futures and to develop long-term, interconnection-wide transmission expansion plans. One goal of the project is to develop cost allocation options related to high voltage transmission lines from geographically constrained renewable resource areas to load centers.[7]

Elsewhere, and borrowing from the natural gas industry, other companies are turning to various types of open seasons to pre-subscribe transmission capacity before proceeding with transmission construction. The exact circumstances may vary, but an open season is generally a competitive solicitation by transmission companies to solicit capacity on a planned or operating transmission project. The rates paid by winning bidders provide the revenue stream necessary for transmission providers to develop the transmission project. For example, the Zephyr and Chinook projects are two proposed 500-kilovolt (kV) high-voltage direct current transmission

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[5] Midwest ISO and the Midwest ISO Transmission Owners, *Midwest Independent Transmission System Operator, Inc et al submits the proposed revisions to their ISO Open Access Transmission, Energy and Operating Reserve Markets Tariff under ER10-1791*, Docket No. ER10-1791 (FERC, July 15, 2010), http://www.midwestiso.org/publish/Document/34542d_129d6210a3e_-7fbd0a48324a/Entire%20Transmission%20Cost%20Allocation%20Filing.pdf?action=download&_property=Attachment.

[6] SPG Coordination Group, *Foundational Transmission Project List,* August 11, 2010, http://www.wecc.biz/committees/BOD/TEPPC/SCG/Shared%20Documents/SCG%20Foundational%20Transmission%20Project%20List%20Report.pdf.

[7] Western Governors Association, "Regional Transmission Expansion Project: Interconnection Level Transmission Planning and Analysis," http://www.westgov.org/index.php?option=com_content&view=article&id=311&Itemid=81.

projects, each with a capacity of 3,000 megawatts (MW) being developed by TransCanada. The Zephyr project would originate in Wyoming while the Chinook project would originate in Montana, with both terminating in the Eldorado Valley south of Las Vegas. In February 2009, FERC granted both projects negotiated rate authority. TransCanada developed a precedent agreement for open seasons that were launched on October 13, 2009. On May 20, 2010, TransCanada announced the results of the Zephyr open season, which resulted in signed precedent agreements for the full 3,000 MW of available capacity on the proposed transmission line with three renewable energy developers in Wyoming – Pathfinder Renewable Wind Energy, Horizon Wind Energy, and BP Wind Energy. TransCanada plans to have the line in-service by 2015/16. In September 2010, TransCanada suspended the Chinook project, citing lack of market support.

A somewhat different example involves the Bonneville Power Administration (BPA), which has run three open seasons for transmission from 2008 through 2010. BPA requires transmission customers to sign a precedent transmission service agreement to remain in BPA's transmission service queue, or otherwise be removed. In doing so, BPA was able to offer transmission service without having to construct new transmission lines. If new lines are needed, BPA will build the transmission project if it can be built at BPA's embedded cost and the proposed transmission project goes through a National Environmental Policy Act (NEPA) review. BPA is now constructing a 500-kV transmission line and is in the process of planning and permitting three additional 500-kV lines.

In June 2010, FERC issued a proposed rule on transmission planning and transmission cost allocation that, among other things, requires transmission providers and RTOs to incorporate state and federal public policy-driven transmission projects into their transmission planning. FERC also proposes to require every transmission provider to participate in a regional transmission planning process, to coordinate with neighboring regional transmission planning processes, and to propose transmission cost allocation criteria that may differ by type of transmission project (e.g., reliability, economic, or public policy-driven). The Notice of Proposed Rulemaking (NOPR) also would allow FERC to impose a transmission cost allocation methodology on a case-by-case basis if a region cannot reach agreement on transmission cost allocation.[8]

This report discusses individual RTO and some non-RTO approaches towards tackling transmission cost allocation. Section II provides an overview of FERC initiatives on transmission and transmission cost allocation. Section III describes RTO initiatives and innovations on transmission cost allocation, and past and projected investments in reliability-based and economic transmission projects. Section IV describes non-RTO initiatives. The report closes with a summary.

[8] Federal Energy Regulatory Commission, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 131 FERC ¶ 61,253, Docket No. RM10-23-000 (FERC, June 17, 2010), http://www.ferc.gov/whats-new/comm-meet/2010/061710/E-9.pdf.

II. Federal Energy Regulatory Commission Initiatives

FERC has jurisdiction over bulk wholesale electricity markets and interstate transmission. FERC has issued three landmark orders intended to enable fair and open access to the transmission grid for all parties and to facilitate non-discriminatory transmission system planning. More recently, FERC has been engaged in reforming transmission planning and cost allocation in an effort to facilitate regional transmission development.

A. FERC Order No. 888

FERC originally issued Order No. 888 in April 1996, requiring all public utilities to adopt the *pro forma* open access transmission tariff (OATT)[9] and provide transmission service for all customers comparable to the transmission service they provide themselves. Order 888 "required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service."[10] Order 888 also set out minimum requirements for transmission planning, both at the local and regional level, that were to be incorporated into the OATT. These broadly outlined requirements applied to all 'Transmission Providers' and included:

- Transmission providers must plan and upgrade their systems to provide comparable open access for all customers.
- Transmission providers must plan, construct, operate, and maintain their systems to provide network customers with network integrated transmission service.
- Transmission providers must make an effort to develop and construct sufficient transfer capability so that network customer resources are able to serve their network loads in a way that is comparable with the transmission provider's service of its native loads.
- Transmission providers will construct new facilities to meet long-term point-to-point customers' service requests if redispatch solutions are not economical, contingent on the customer agreeing to compensate the transmission provider for the cost.[11]

Order 888 also encouraged utilities and transmission providers to conduct joint planning with other transmission providers and customers, and to engage in regional planning efforts, but did not set it as a requirement.

[9] Unless the variations to the pro forma tariffs in individual public utility open access tariffs are found by FERC to be superior to the pro forma tariff.
[10] Federal Energy Regulatory Commission, History of OATT Reform, http://www.ferc.gov/industries/electric/indus-act/oatt-reform/history.asp (accessed March 27, 2009).
[11] Federal Energy Regulatory Commission, *Order No. 890: Preventing Undue Discrimination and Preference in Transmission Service*, Docket Nos. RM05-17-000 and RM05-25-000 (FERC, February 16, 2007), http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

B. FERC Order No. 2003

In July 2003, FERC issued Order No. 2003 directing transmission providers to revise their open access transmission tariffs to include the standardized Large Generator Interconnection Procedures contained in the Order. The procedures and rules governing generator interconnection were subsequently reaffirmed and clarified under Orders 2003-A in March 2004, 2003-B in December 2004, and 2003-C in June 2005.[12]

Included in Order 2003 are policies for how interconnection and transmission grid reinforcement costs should be allocated. The order identifies two types of construction costs that are associated with generation interconnection:

- Direct connection facilities – all equipment and construction required to connect the new generating facility to the first point of interconnection with the transmission grid.
- Network transmission upgrades – the equipment and construction required to reinforce the existing transmission system in order to accommodate the new generation project.

Under Order 2003, the generators are responsible for the cost of all direct connection facilities between the generator and the transmission grid. Generators must also provide the funding for the cost of any network upgrades and new additions to the transmission network that are required as a result of the interconnection. However, Order 2003 states that generators should be fully reimbursed for the network upgrade costs by transmission providers within five years, with interest. The reimbursement can be in the form of credits against the costs of transmission service or, if available, financial transmission rights (FTRs).

Order 2003 allows RTOs and Independent System Operators (ISOs) to propose variations to the interconnection policies and procedures contained in Order 2003. FERC stated that an RTO or ISO has "different operating characteristics depending on [its] size and location and is less likely to act in an unduly discriminatory manner than a Transmission Provider that is a market participant."[13] Therefore, an RTO or ISO is considered an "independent entity" and can propose variations to Order 2003 that are "just and reasonable and not unduly discriminatory and would accomplish the purposes of Order 2003."[14] Some RTOs and ISOs have used the independent entity variation to propose alternative cost allocation methodologies for transmission upgrades and for interconnecting new generators.

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[12] Federal Energy Regulatory Commission, *Order No. 2003*: *Standardization of Generator Interconnection Agreements and Procedures*, Aug. 19, 2003, Order No. 2003-A, Mar. 26, 2004, Order No. 2003-B, Jan. 4, 2005.
[13] Ibid., 827.
[14] Federal Energy Regulatory Commission, *Interconnection Queuing Practices: Order on Technical Conference*, 122 FERC ¶ 61,252, Docket No. AD08-2-000 (FERC, March 20, 2008), p.5, note 10, http://www.ferc.gov/whats-new/comm-meet/2008/032008/E-27.pdf.

C. FERC Order 890

In February 2007, FERC issued Order No. 890, which amended certain aspects of the OATT that FERC felt were deficient. FERC noted in the Order that transmission investment relative to load growth had declined in the decade following Order 888, transmission capacity per MW of peak demand had gone down in every region, and transmission constraints had become common occurrences. Order 890 directs (among other things) transmission providers to conduct local and regional level transmission planning in a coordinated, open, and transparent manner. FERC allows for regional differences in transmission planning, but each transmission planning process must incorporate the following nine criteria:

1. Coordination – transmission providers are required to meet with all of their customers and neighboring interconnected providers when developing transmission plans. FERC did not prescribe conditions for how such meetings should be conducted, but directed transmission providers to craft requirements through a stakeholder process that are appropriate to their particular circumstances.
2. Openness – transmission planning meetings must be open to all affected parties including customers, state commissions, and other stakeholders. To alleviate concerns regarding privacy of information, FERC directed transmission providers to develop systems for safeguarding private information, such as the use of confidentiality agreements. Transmission providers are required to consult with affected parties when developing these systems.
3. Transparency – transmission providers are required to disclose the basic criteria, assumptions, and data used to create transmission system plans. This disclosure must be in writing, include information on how the transmission provider treats its native load, and be sufficient to allow customers and stakeholders to recreate the results.
4. Information Exchange – network customers and point-to-point customers are required to submit information on their projected loads and resources, that is comparable to what transmission providers must disclose regarding their native loads. Guidelines and schedules for information exchange must be developed through a consultative process.
5. Comparability – transmission providers must use the information arising from the information exchange to develop transmission system plans that meet the specific requests of their customers in a way that treats all similarly-situated customers comparably. FERC notes that comparability does not imply each customer should be treated the same, rather that no particular customer's interests (including the transmission provider's) should be put ahead of any others.
6. Dispute Resolution – transmission providers must include a system for resolving disputes in their transmission planning process.

7. Regional Coordination – transmission providers are required to coordinate their planning with other interconnected systems. Transmission providers must share their system plans to ensure simultaneous feasibility and consistency of assumptions and data, and to identify system upgrades to address congestion. FERC notes that several voluntary regional planning efforts have been created in the last few years and allows that the specifics of regional planning take account of existing institutions and can be tailored to the particular needs and characteristics of each region. FERC did not mandate the geographic scope of any particular regions, but noted it should be driven by regional and sub-regional reliability and resource issues.
8. Economic Planning Studies – transmission providers are required to conduct studies that identify 'significant and recurring' transmission congestion. These studies must analyze the location, magnitude, and associated costs of significant congestion, propose possible solutions, and include the cost the implementing those solutions. The studies must also be made available to stakeholders via an OASIS[15] posting. FERC states that the reason for including this requirement is to ensure that transmission planning incorporates more than just reliability issues, and also considers how investments in certain upgrades can reduce overall system costs and facilitate the integration of new resources. FERC directed transmission providers to consult with stakeholders in developing a system for performing economic studies in an efficient manner and to post requests for, and responses to, economic studies requests on their OASIS or web sites.
9. Cost Allocation – transmission providers were directed to undertake a stakeholder process to create and propose a cost allocation methodology appropriate to their particular regions. FERC included a rule for cost allocation of new transmission facilities, but emphasized that the rule was not for projects constructed by a single transmission owner. The rule would apply only to projects that do not fall into existing categories, such as regional multi-owner projects and economic projects arising from Order 890 planning processes. FERC provided the following set of factors that would be considered when making judgments on cost allocation disputes:
    - Whether costs are fairly allocated among participants, including beneficiaries.
    - Whether the cost allocation proposal provides adequate incentives to construct new transmission.

[15] OASIS stands for Open Access Same-time Information System. It is an electronic real-time information system which allows for non-discriminatory access to transmission information and services. Transmission providers are required to operate or be party to OASIS interfaces and must post specified information concerning their transmission systems, including total transmission capacity, available transmission capacity, and capacity available for resale by third parties.

- o Whether the proposal is generally supported by state authorities and participants across the region.[16]

FERC noted that these factors are interrelated and will be especially important with respect to the economic transmission upgrade projects that will result from the regional planning processes.

FERC directed transmission providers to submit an Order 890 compliance filing within 210 days of the final rule's release (February 2007) outlining (among other things) how their transmission planning procedures complied with the nine planning criteria. Each filing was required to include a proposed Attachment K, which described the transmission planning process, for inclusion in the OATT. [17]

D. FERC's June 2010 Notice of Proposed Rulemaking on Transmission Planning and Cost Allocation

On June 17, 2010, FERC issued a NOPR to amend the transmission planning and cost allocation requirements established in Order 890.[18] FERC notes in the NOPR that at the regional level, Order 890 requirements have substantially improved transmission planning processes. FERC's intent is not to interrupt the progress that has been made, but to address any remaining deficiencies:

- The lack of a requirement for a regional transmission plan.
- No mechanism for transmission planners to include planning to meet state and federal policy imperatives (for example, Renewable Portfolio Standard, or RPS, requirements).
- Non-incumbent transmission developers not being able to participate on equal footing with incumbent transmission owners in regional transmission planning.
- A relative lack of coordination between transmission planning regions.
- Existing methods for cost allocation for new transmission projects may not be meeting FERC's goals of providing for facilities that product just and reasonable rates.

Proposed Transmission Planning Reforms

FERC proposes the following reforms with respect to transmission planning, non-incumbent developer inclusion, and cost allocation:

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[16] Federal Energy Regulatory Commission, *Order No. 890: Preventing Undue Discrimination and Preference in Transmission Service*, Docket Nos. RM05-17-000 and RM05-25-000 (FERC, February 16, 2007), p.321, http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

[17] Some ISO/RTOs revised existing Attachments, therefore, not all tariffs contain a Planning Attachment labeled 'K'.

[18] Federal Energy Regulatory Commission, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Notice of Proposed Rulemaking, 131 FERC ¶ 61,253, Docket No. RM10-23-000 (FERC, June 17, 2010), http://www.ferc.gov/whats-new/comm-meet/2010/061710/E-9.pdf.

1. Transmission Planning:

    - Regional Planning Process −

      Each public utility transmission provider will be required to participate in a regional transmission planning process. Both the individual local transmission plans and the regional plans will consider and evaluate both transmission and non-transmission solutions that may have been proposed to create a plan that meets the needs of transmission customers and other stakeholders.

    - Public Policy Driven Projects −

      Amendments will be required to OATTs to include procedures and mechanisms that ensure local and regional transmission planning processes and incorporate consideration of requirements established by state and federal laws and regulations.

2. Non-incumbent Transmission Developers:

    In some regions, incumbent transmission owners have a right of first refusal to build transmission facilities. FERC states that this creates opportunities for undue discrimination and preferential treatment for transmission owners, putting non-incumbent transmission developers at a disadvantage. FERC proposes to direct all public utilities to revise their OATT to remove any right of first refusal provisions and create ways for non-incumbent developers to participate in transmission planning and submit project proposals.

3. Interregional Coordination:

    Each public utility will be required through the regional planning process to coordinate with neighboring transmission planning regions and create an interregional transmission planning agreement.

4. Cost Allocation:

    FERC proposes to amend Order 890 to include additional cost allocation criteria that will link transmission planning and cost allocation. Each public utility transmission provider will be required to include a method for allocating costs for new transmission facilities arising from the transmission planning processes in which they participate. The methodology can include different cost allocation schemes for different types of projects driven by different needs, i.e., reliability, economic, and public policies. The cost allocation methodologies will follow principles that FERC sets out, with one set of principles for intraregional facility cost allocation and another for interregional facilities.

III. RTO/ISO Economic Planning and Cost Allocation

This section summarizes RTO and ISO transmission planning activities, as well as significant non-RTO transmission planning initiatives. If available, data on proposed customers in reliability-driven and economic transmission projects is also presented. Some RTOs/ISOs have been examining ways to better enable economic planning and allow them to meet relevant public policy objectives. Much of this activity has focused on finding ways to develop transmission that would enable the growth of renewable energy resources.

A. California Independent System Operator

The California Independent System Operator (CAISO) identifies, evaluates, and approves new transmission facilities through its transmission planning process. Transmission projects are characterized as reliability transmission projects, economic transmission projects, Location Constrained Resource Interconnection Facilities (LCRI), Long-term Congestion Revenue Right Feasibility (LT-CRR) Projects, and Merchant projects. Network projects that are reliability-driven projects are judged according to standard planning criteria used to quantify system performance as provided by the North American Electric Reliability Council, the Western Electric Coordinating Council, and CAISO in their planning standards. The capital costs of the network upgrades are "rolled-in" to general transmission rates of the participating transmission owners and recovered through CAISO's grid-wide Transmission Access Charge (TAC), subject to FERC oversight and approval. If the network upgrades occur as the result of a planned interconnection of a large generator facility, the generator owner may be required to pay for the upfront capital costs. The generator owner is eventually reimbursed for these costs, however, and the participating transmission owner may, at its own election, agree to initially pay for the necessary network upgrades, thereby relieving the generator owner of the upfront capital costs.

Long-term CRR feasibility projects are upgrades or additions identified by the ISO during the annual transmission planning cycle as needed to ensure the feasibility of previously released long-term CRRs for their full ten-year term. FERC established this requirement in its 2006 orders on Long Term Firm Transmission Rights in Organized Electricity Markets. If any such upgrades are found to be needed, their costs are recovered through the CAISO's TAC.

Merchant projects are transmission upgrades and additions that are turned over to CAISO operational control and for which the developer has decided to forego rate-based recovery of the investment cost through the TAC. The merchant is eligible to receive an allocation of 30-year option CRRs (Merchant CRRs) in a quantity that reflects the incremental capacity the merchant project adds to the CAISO grid.

The economically-driven network transmission projects include those projects where the economic benefits of the upgrade or addition are expected to exceed its costs and may serve to lower a region's energy production costs, reduce or eliminate congestion, or reduce capacity costs. Economic projects are evaluated by criteria defined in the CAISO Transmission Economic Assessment Methodology (TEAM) that includes a standardized cost-benefit analysis framework.[19] Economically-driven projects proposed by a participating transmission owner, market participant(s), the California Public Utilities Commission (CPUC), or California Energy Commission (CEC) that are found to be beneficial according to the TEAM evaluation are approved by CAISO. Approved projects are provided with cost recovery through CAISO's FERC approved TAC in the same manner as reliability-driven network upgrades.

To date, relatively few economically-driven transmission projects in the CAISO region have been proposed and approved. Two prominent examples include:

1) The Devers-Palo Verde No. 2 (DPV2) transmission line project. The CPUC approved the project based on its economic benefits to consumers. The CPUC found that the project would allow for greater access to low-cost, surplus generation in Arizona; enhance competition among the generating companies that supply energy to California; and support the entry of new energy suppliers to the California energy markets thereby increasing liquidity and reducing market power. The DPV2 project was proposed by Southern California Edison and would provide transmission capacity between Arizona and southern California; however, the Arizona Corporation Commission denied a permit to the DPV2 project in June 2007. Southern California Edison withdrew its application to develop the Arizona portion of the DPV2 line, but is continuing to pursue the California portion of the project.

2) The Tehachapi Renewable Transmission Project. The Tehachapi project was approved by the CPUC in March 2007. The need assessment for the project included consideration of its role in supporting California's RPS goals. The project is being developed in three segments and will deliver electricity from new wind farms in the Tehachapi area to Southern California Edison. The project includes three new 500-kV transmission lines currently under construction and projected to be completed in 2012.

To facilitate economic transmission projects in support of renewable energy development, CAISO has created and is participating in several renewables-focused transmission development initiatives in California. On April 19, 2007, FERC granted CAISO's petition for a declaratory order approving the LCRI financing mechanism. CAISO's proposed financing mechanism was developed to connect multiple location-constrained renewable resources to the CAISO grid and to roll-in the costs of these facilities through the transmission owner's transmission revenue requirement and subsequent TACs. The generators that interconnect to the grid are responsible for paying a *pro rata* share of the going-forward costs of the line (through TAC) until the line is fully subscribed and the transmission owner is "re-paid" for its initial investment. Eligibility for

[19] Cost-benefit analysis is a technique designed to determine the feasibility of a project or plan by quantifying and comparing its costs versus its benefits and is generally equal to the net present value of benefits divided by the net present value of costs.

this rate treatment will be contingent upon the interconnection facility being approved in the CAISO transmission planning process as a facility that provides access to location constrained resources and provides needed system benefits. Total investment in LCRI facilities is capped at 15% of the total of the net high-voltage transmission assets of participating transmission owners in the CAISO, or about $139 million as of 2009. On May 18, 2009, CAISO approved its first LCRI project. The Highwind Transmission Project will include 10 miles of new transmission line and a new substation to the Tehachapi area, at a cost of $46.1 million.

In 2007, the CPUC, the CEC, CAISO, and California's Publicly-Owned Utilities (POU) launched the California Renewable Energy Transmission Initiative (RETI) to identify Competitive Renewable Energy Zones (CREZ) and the transmission needed to access them. In Phase I, RETI identified and ranked CREZs in California and neighboring areas with significant renewable energy potential that could be developed in time to meet the State's renewable energy goal of 33% of energy supply by 2020. The final Phase I report, released in January 2009, identified numerous potential zones, with the six highest-ranked in-state CREZs having a combined potential energy output of 74,300 gigawatt-hours (GWh) per year.[20] The final Phase II report, released in August 2009, refined the CREZ analysis and outlined high-level conceptual transmission development needed to access the 96,000 GWhs from 31 of the highest-ranked CREZs and thus facilitate meeting the 33% goal.[21]

During the 2009 transmission planning cycle and in conjunction with RETI, CAISO began exploring conceptual renewable energy transmission plans that could support the RETI recommendations and allow the CAISO to develop the transmission needed to reach the 33% renewable energy by 2020 goal. The initial conceptual transmission plan was released in September 2009 based on a set of completed Phase I RETI technical studies and aimed at providing transmission access to 69,000 GWh from 14 CREZs.[22] CAISO estimated that an additional 26,875 MW of transmission capacity would be required to transport the energy from the CREZs to California consumers.

CAISO also engaged in an extensive stakeholder process aimed at creating a revised transmission planning process that would support development of the transmission needed for renewable energy. On June 4, 2010, CAISO submitted a filing to FERC requesting approval for a Revised Transmission Planning Process (RTPP).[23] CAISO states the RTPP is needed for CAISO to support California meeting the 33% renewable energy goal. By 2020, the RTPP would create

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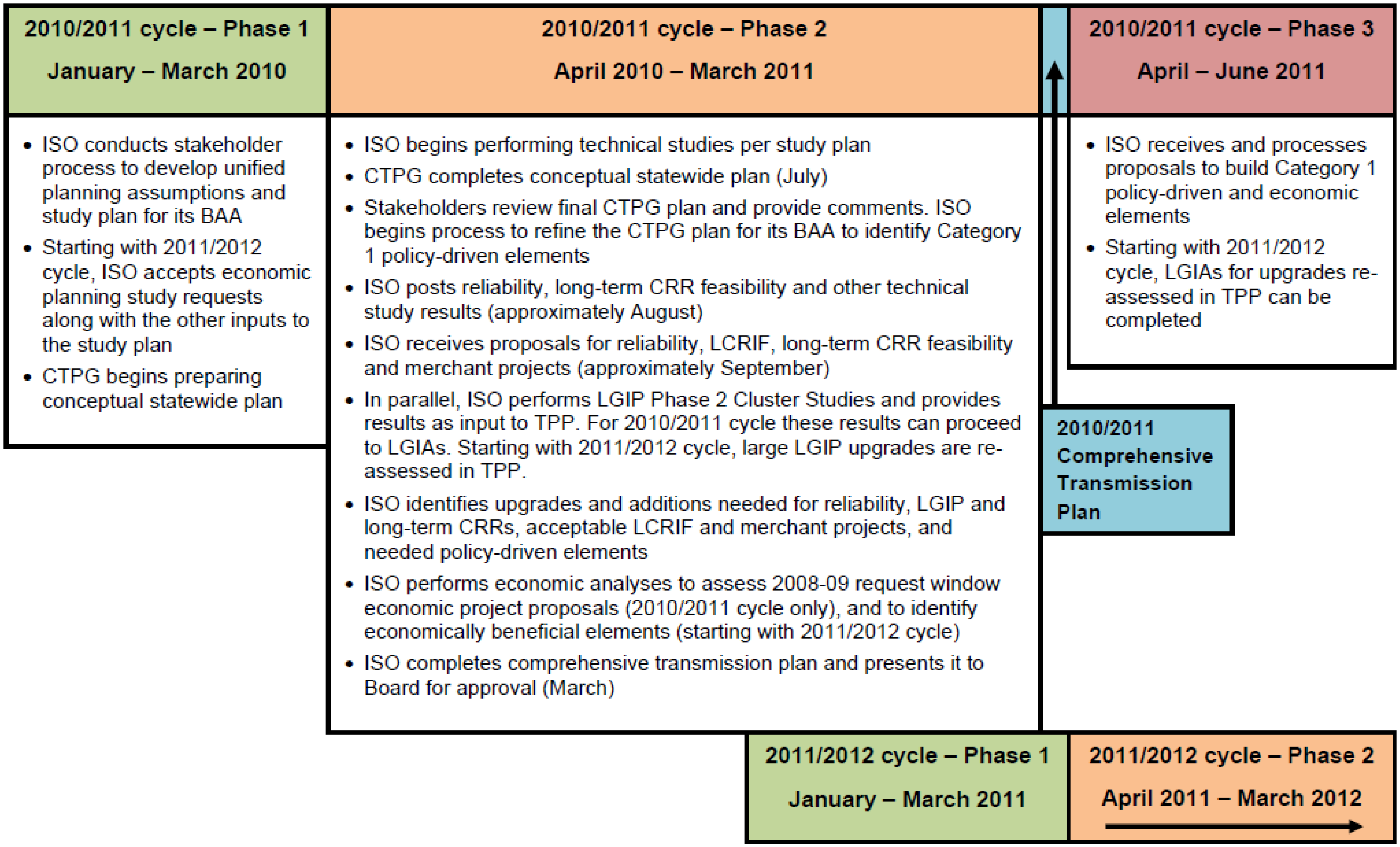
[20] RETI Stakeholder Steering Committee, *Renewable Energy Transmission Initiative, Phase 1B, Final Report*, December 2008, http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-PF.PDF.
[21] RETI Stakeholder Steering Committee, *Renewable Energy Transmission Initiative, Phase 2A, Final Report*, September 2009, http://www.energy.ca.gov/2009publications/RETI-1000-2009-001/RETI-1000-2009-001-F-REV2.PDF.
[22] California ISO, *2020 Renewable Transmission Conceptual Plan Based on Inputs from the RETI Process*, September 15, 2009, http://www.caiso.com/242a/242ae729af70.pdf.
[23] California Independent System Operator, *Revised Transmission Planning Process Proposal*, Docket No. ER10-1401 (FERC, June 4, 2010), http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12361568.

a single comprehensive transmission plan for CAISO that, along with meeting CAISO's current planning imperatives, would also include transmission projects driven by environmental policy goals. The RTPP would establish a new category of transmission projects, called 'policy-driven' that are needed to meet state and federal policy requirements and directives. It would also create a way for all interested parties to propose, own, and construct the policy-driven transmission facilities and any other economic projects. The RTPP proposed to eliminate the right of first refusal provision with respect to policy-driven and economic projects, and create a request window wherein all interested parties will be able to submit proposals for these projects that will then be evaluated equally within CAISO's transmission planning process. Responsibility for, and right of first refusal provisions for, reliability-driven projects, generator network upgrades, LCRI projects, and CRR-driven projects will remain unchanged. The RTPP would be conducted in phases, beginning with the 2010 to 2011 planning cycle (see Figure 2).

On July 26, FERC issued an order conditionally accepting and suspending CAISO's proposed tariff revisions for establishing RTPP.[24] FERC noted that several parties had filed in opposition to certain elements of the proposal especially with respect to the remaining right of first refusal and construction provisions. Intervening entities argue that incumbent transmission owner's rights are still too broad. Interveners also question the definitions for the new project categories and the selection process for competing projects. These protestors contend the project categories are too vague and CAISO retains too much discretion over how to identify and classify policy-driven projects. FERC lauds the RTPP proposal as being innovative but states the tariff revisions lack adequate specificity and clarity for a definitive ruling. FERC therefore directs staff to convene a technical conference for a closer examination of the issues raised, within 45 days of the order.

[24] Federal Energy Regulatory Commission, *Order Conditionally Accepting and Suspending Proposed Tariff Revisions and Establishing Technical Conference*, 132 FERC ¶ 61,067, Docket No. ER10-1401 (FERC, July 26, 2010), http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12398323.

Figure 2. Revised California ISO Transmission Planning Process



Source: California ISO, *Revised Transmission Planning Process, Complete Final Proposal*, May 7, 2010, p.4, http://www.caiso.com/278f/278fb6a0148f0.pdf.

B. Southwest Power Pool

Prior to the 2010 planning year, the Southwest Power Pool (SPP) produced an annual SPP Transmission Expansion Plan (STEP), which contained a regional ten-year projection of expected transmission expansions and upgrades within SPP. The STEP included transmission projects from four sources: reliability upgrades needed to satisfy reliability criteria (i.e., NERC standards), economic projects, transmission service and generation interconnection requests, and customer funded projects. [25]

Projects arising from the STEP were classified as Base Plan Upgrades (including reliability upgrades). Base Plan Upgrades that cost $100,000 or less were paid for by the relevant zone. Base Plan Upgrades that cost more than $100,000 were funded under regional postage stamp rates.

Balanced Portfolio Economic Projects in SPP

The SPP region is rich in generation resources but lacks adequate transmission to fully develop it. SPP recognized that extensive regional transmission development would be required to access SPP's wind resources. In 2005, SPP's Cost Allocation Working Group (CAWG) began working with SPP stakeholders to develop a new economic transmission planning and cost allocation methodology. The CAWG issued a concept paper outlining the Balanced Portfolio approach in late 2007. Subsequently, the SPP's Regional Tariff Working Group developed tariff language incorporating the Balanced Portfolio into SPP's Order 890 planning process, resulting in a tariff filing to FERC on August 15, 2008.[26] FERC approved the filing (with modifications) on October 16, 2008.[27]

Under the Balanced Portfolio approach, SPP evaluated portfolios of economic transmission upgrade projects. To be considered a Balanced Portfolio, the set of transmission projects needed to meet the following criteria:

- The portfolio is cost beneficial, i.e., the sum of the net present value of total benefits is equal to or greater than the sum of the net present value of total costs over a 10-year period.

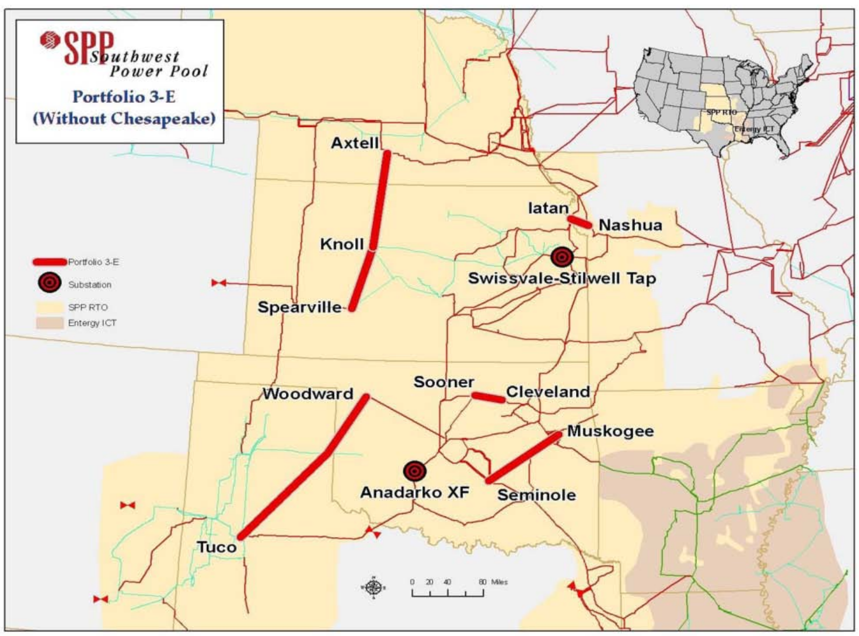
[25] Southwest Power Pool, *Open Access Transmission Tariff for Services Offered by Southwest Power Pool*, http://www.spp.org/publications/SPP_Tariff.pdf (accessed July 15, 2010).
[26] Southwest Power Pool, *Submission of Revisions to Open Access Transmission Tariff to Add "Balanced Portfolio" Cost Allocation Process for Economic Planning Upgrades*, Docket No. ER08-1419-000 (FERC, August 15, 2008), http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=11784442.
[27] Federal Energy Regulatory Commission, *Order Accepting Tariff Revisions, as Modified*, Docket No. ER08-1419-000 (FERC, October 16, 2008), http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=11831541.

- The portfolio is balanced, i.e., for each individual zone, the sum of the net present value of zonal benefits must be equal to or greater than the sum of the net present value of zonal costs, over the same 10-year period.

When designing the Balanced Portfolio, SPP also considered including lower voltage transmission upgrades for a zone if the benefit/cost ratio for that zone was less than one. In identifying portfolios, SPP used input from customers and stakeholders, in addition to SPP's own assessment of the congestion and load relief that was required. The cost of the Balanced Portfolio economic projects will be recovered 100% through SPP's regional postage-stamp rate.

In April 2009, the SPP Regional State Committee, SPP's Board of Directors and SPP's Members Committee approved the first Balanced Portfolio, projected to cost over $700 million. SPP examined over 50 different projects to create a portfolio that met the regional criteria. The projects in the Balanced Portfolio included five new transmission lines and two new substations (see Figure 3).

Figure 3. SPP's Balanced Portfolio



Source: Southwest Power Pool, *Portfolio of New EHV Transmission Projects Approved: Benefits Will Be Balanced across SPP Region*, April 29, 2009, Press Release, p.2, http://www.spp.org/publications/Transmission_Project_Portfolio_Approved_4_29_09.pdf.

Synergistic Planning Project

In January 2009, SPP formed the Synergistic Planning Project Team (SPPT) to explore the possible creation of a more comprehensive transmission planning process. The aim of the SPPT was to examine how the STEP, the Balanced Portfolio, the SPP Extra High Voltage (EHV)

Overlay studies[28], and the transmission and interconnection queues could be integrated into a comprehensive planning process. The main impetus for forming the SPPT was the desire to amalgamate all of the various planning processes into a single holistic comprehensive planning process and to reconcile and merge the different cost allocation methodologies.

The SPPT issued its first report on April 23, 2009, outlining recommendations for synergistic planning principles, a new integrated planning process, regional cost allocation, near-term transition priorities, and an action plan. [29] The SPPT recommended that:

- Planning incorporates all factors including (but not limited to) generation, load growth, demand response, energy efficiency, fuel prices, and environmental and governmental regulations and policies.
- A new integrated planning process is created that includes a long-range plan with back-bone transmission expansion projects with fortifying ties to other interconnections. This long-range plan would be updated every three years and cover a 20-year time horizon with a 40-year financial assessment.
- A new simplified regional cost allocation methodology is created based on a highway-byway model. Under this model, all transmission upgrades arising from the integrated plan 345 kV and above should be considered part of the highway and funded through a regional postage stamp rate, and facilities below 345 kV would be considered byways and funded through zonal rates.

Integrated Transmission Planning Process

Following the recommendations from the SPPT, SPP created the Integrated Transmission Planning (ITP) process, which was filed at FERC in May 2010.[30] The ITP integrates the Priority Projects (described below), the Balanced Portfolio, and the STEP reliability assessment. It involves a three-year iterative process with an annual reliability assessment, a 20-year long-term assessment that begins in year one and is finished in year two, and a 10-year mid-term assessment beginning in year two and completed in year three. The ITP design aims to create a reasonable balance between long-term transmission investment and congestion costs, which will be reduced as new transmission is constructed. The ITP iterative process is as follows:

[28] The SPP EHV Overlay project consists of an assessment of several high-voltage backbone transmission line scenarios needed over the next 20 years that could also enable over 20,000 MW of wind power development.
[29] Southwest Power Pool, *Report of the Synergistic Planning Project*, April 23, 2009, Version 6.1, http://www.spp.org/publications/SPPT%20Report%20Version%20v6-1.pdf.
[30] Southwest Power Pool, *Submission of Revisions to Open Access Transmission Tariff to Incorporate Integrated Transmission Plan*, Docket No. ER10-1269 (FERC, May 17, 2010), http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12348309.

1. Triennial 20-Year Assessment −

   This will be the first phase initiated every three years and used to develop 300 kV and above rated backbone facilities. The projects identified in this assessment must pass a regionally beneficial test across multiple scenarios.

2. Triennial 10-Year Assessment −

   The second phase will be initiated every three years in the second half of the three-year planning cycle and will identify 100 kV and above facilities needed within 10 years. The 10-Year Assessment will aim to meet the following needs: eliminate criteria violations, mitigate known or projected congestion, improve market access, backbone transmission expansion staging, and improve interconnections.

3. Annual Near Term Assessment −

   This third phase will be performed annually in a rolling window and focus primarily on SPP's obligations with respect to NERC reliability standards and local transmission planning by SPP's transmission owners.

FERC approved the ITP on July 15, 2010, and SPP plans to transition to the ITP process under a compressed timeline, with the first 20-year plan completed by January 2011 and the first 10-year plan by January 2012.[31]

Highway/Byway Transmission Cost Allocation

Development of a Highway/Byway cost allocation methodology was assigned to the SPP CAWG. On October 26, 2009, the SPP Regional State Committee approved CAWG's proposed highway/byway design and directed the Regional Tariff Working Group (RTWG) to develop the necessary tariff language to implement it. The resultant tariff language was submitted to FERC on April 19, 2010, and subsequently approved by FERC on June 17, 2010.[32]

The approved Highway/Byway cost allocation methodology will apply to transmission facilities arising from SPP's Integrated Transmission Plan. To fund projects arising from the ITP, the methodology is as follows:

- For transmission facilities with a voltage level ≥ 300 kV – costs will be assigned 100% to a regional postage stamp rate.

[31] Federal Energy Regulatory Commission, *Order Conditionally Accepting Tariff Revisions*, 132 FERC ¶ 61,042, Docket No. ER10-1269 (FERC, July 15, 2010), http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12389810.
[32] Southwest Power Pool, *Submission of Tariff Revisions to Modify Transmission Cost Allocation Methodology*, Docket No. ER10-1069 (FERC, April 19, 2010), http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12326047.

- For transmission facilities with a voltage level < 300 kV and > 100 kV – costs will be assigned 33% regional and 67% zonal.
- Transmission facilities with a voltage level ≤ 100 kV – costs will be assigned 100% zonal.

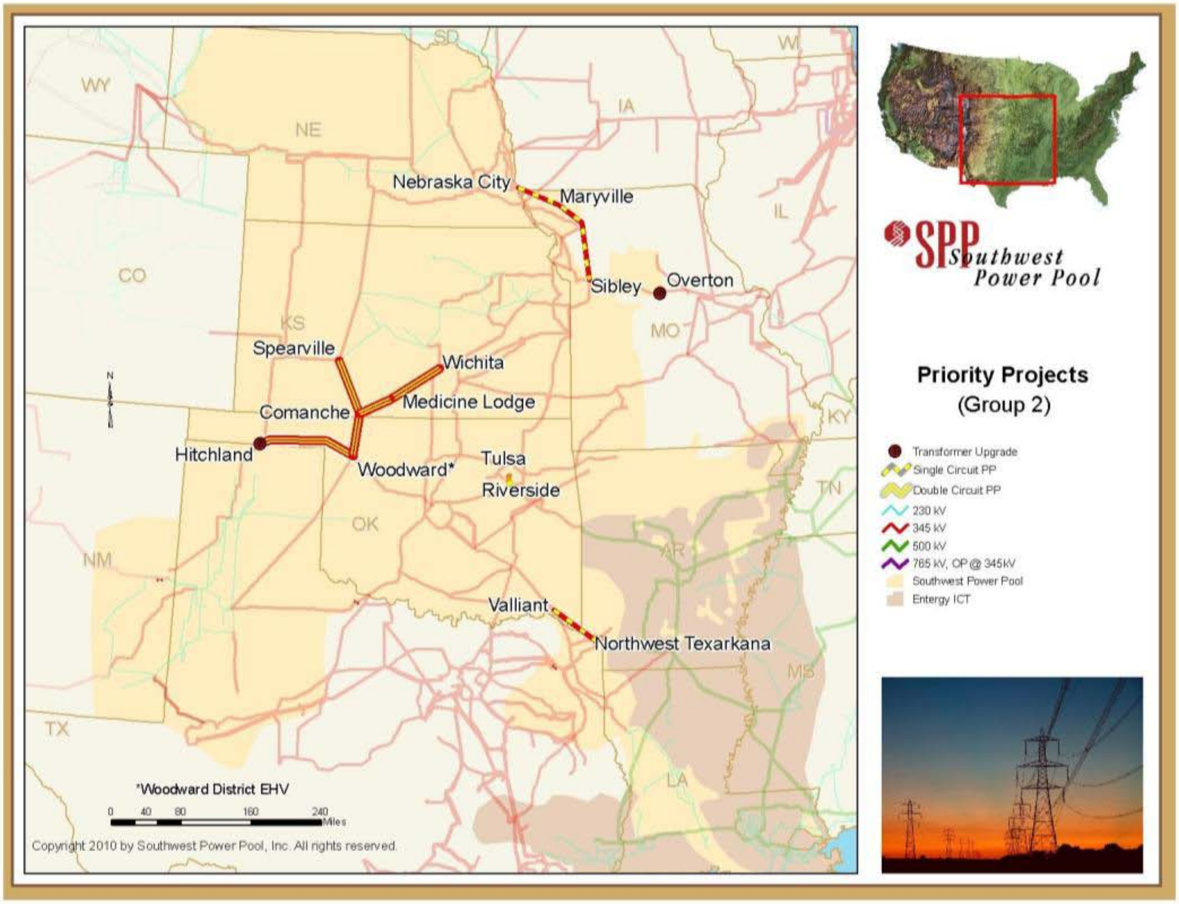
The above cost allocation will also apply to transmission projects associated with qualifying wind generator interconnections if the wind facility is located within the same zone as the load customer. If the wind facility is in a different zone than the point of delivery, the costs will be allocated regionally for facilities operating at 300 kV or above; and for those less than 300 kV, 67% of the cost will be allocated regionally and 33% will allocated to the transmission customer.

Priority Projects

The SPPT also recommended creating a 'Priority Projects' list for expedited implementation. In September 2009, SPP staff released the Priority Projects Phase I Report that analyzed two future scenarios, one containing 7 gigawatts (GW) of wind (10% of SPP supply) and one containing 14 GW of wind (20% of SPP supply) in the SPP footprint. The Phase I Report proposed two 345-kV lines, two 765-kV lines, and a new substation for a total cost of $1.33 billion.[33] Following stakeholder feedback, primarily concerning the cost, SPP staff conducted additional analysis on two Priority Project groups with projected wind capacity at 7 GW and 11 GW. The 11 GW scenario reflected SPP member estimates of the amount of wind that would be required to meet state RPS targets within SPP. The analysis examined the same six transmission projects in two configurations: Group 1 with two lines at 765-kV and four at 345-kV, and Group 2 containing all six lines at 345-kV lines. Group 1 engineering and construction costs were estimated to be $1.26 billion and Group 2 was estimated to be $1.11 billion.[34] SPP analysis demonstrated that Group 2 had a combined quantitative and qualitative benefit/cost ratio of 1.78 from the construction of the transmission projects and the addition of 3.2 GW of wind. On April 27, 2010, the SPP Board approved the Group 2 set of projects as Priority Projects to be funded through the highway/byway cost allocation methodology (see Figure 4).

[33] Southwest Power Pool, *Priority Project Report Summary*, Presentation by Bruce Rew at Priority Projects Workshop, September 29, 2009.
[34] Southwest Power Pool, *SPP Priority Projects Phase II Report Revision 1*, Maintained by SPP Engineering/Planning, April 2, 2010.

Figure 4. SPP Priority Projects



Source: Southwest Power Pool, *SPP Approves Construction of New Electric Transmission Infrastructure To Bring $3.7 Billion in Regional Benefits*, April 27, 2010, Press Release, p.1, http://www.spp.org/publications/Priority_Projects_Approved_4-27-10.pdf.

Generator Interconnection Network Upgrades

Network upgrades identified for generator interconnections can be eligible for regional cost recovery if the generator is designated as a network resource, as defined under Order 2003,[35] and if the following criteria are met:

- The generator commits to being a network resource for at least five years;
- In the first year the new network resource is used, the transmission customer's total maximum capacity shall not exceed 125% of the projected system peak responsibility, i.e., the transmission customer or load serving entity cannot designate a generator as a

[35] Order 2003 identifies two types of generator interconnection, Energy Only and Network Resource. Energy Only resources are eligible to deliver energy to the network on an as-available basis. Network Resources are considered electricity network system capacity resources and eligible to participate in all capacity-related services in addition to energy-related services.

network resource if the load serving entity's system does not need the capacity to meet its capacity obligation; and

- The cost does not exceed SPP's Safe Harbor Cost Limit.

Under the Safe Harbor Policy, SPP will reject projects for regional cost recovery if the network upgrades exceed the Safe Harbor Limit, which is calculated as follows: $180,000 per MW times the lesser of (1) the planned maximum net dependable capacity of the project, or (2) the requested capacity of the resource designation. SPP will however, allow these projects to apply for a waiver. SPP will then examine whether the project can provide benefits to the system as a whole.

The Safe Harbor calculation is based on the net dependable capacity of wind resources. Due to wind's variable output, SPP previously assigned a net dependable capacity value to wind equal to 10% of their nameplate capacity. This led to the level of network upgrade costs that were eligible for regional cost recovery being much lower for wind projects, which resulted in the zones hosting wind power projects bearing more of the transmission costs. On June 18, 2009, FERC approved an SPP tariff revision modifying the Safe Harbor Limit policy so that the requested capacity for SPP's wind resources instead of the net dependable capacity will always be applied when calculating the limit for wind projects.[36]

Past and Projected Transmission Investment

SPP has been by far the most active FERC-regulated ISO/RTO in enabling the development of economic transmission projects, with $700 million approved for the Balanced Portfolio projects and $1.11 billion for the high voltage Priority Projects. SPP's new ITP process is expected to create comprehensive future transmission plans for meeting both the reliability and economic needs of the region. Figures 5 and 6 below outline the reliability and economically-oriented past and projected expenditures for SPP.

[36] Federal Energy Regulatory Commission, *Order Conditionally Accepting Tariff Revisions*, 127 FERC ¶ 61,283, Docket No. ER09-1039-000 (FERC, June 18, 2009), http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12049788.

Figure 5. Cumulative Reliability-Based Transmission Investment in SPP

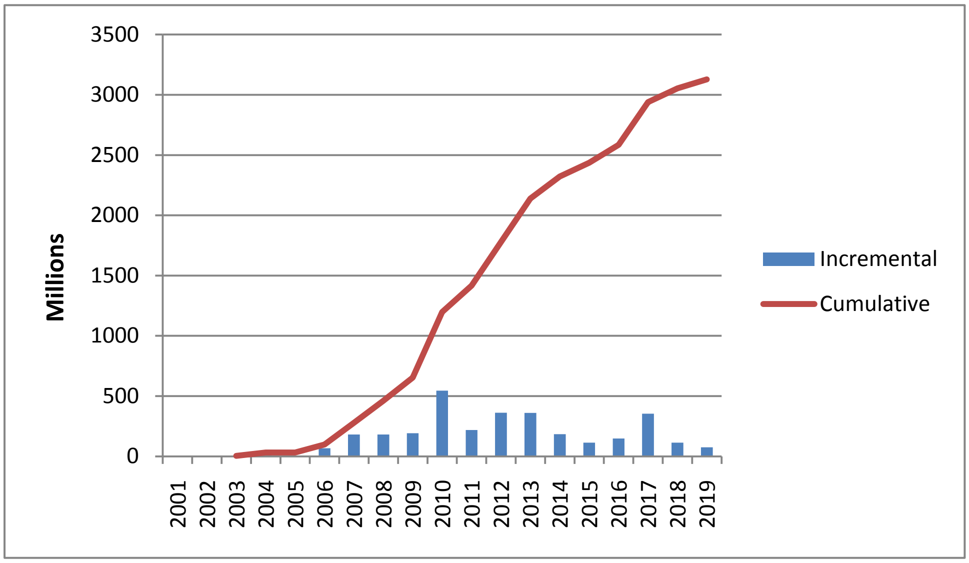
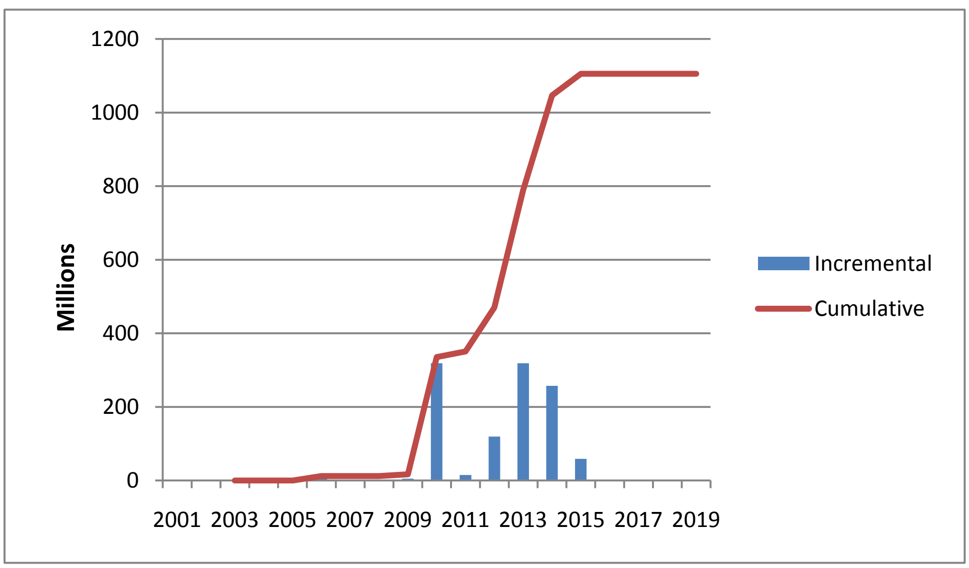


Figure 6. Cumulative Economic-Based Transmission Investment in SPP



C. Midwest Independent Transmission System Operator

The Midwest ISO annually produces a Midwest ISO Transmission Expansion Plan (MTEP) containing the following categories of transmission projects:

- Baseline Reliability Projects (BRP) – projects identified in the base case as needed to maintain reliability of the transmission system in with costs allocated as described below.
- Transmission Access Projects (TAP) – two types of projects fall into this category: (1) generation interconnection projects (GIP), which are network upgrades associated with interconnecting new generation projects to the grid; and (2) transmission delivery service projects (TDSP) which are upgrades needed in response to new point-to-point transmission service requests.
- Regionally Beneficial Projects (RBP) – these are economic projects that are proposed by transmission providers, transmission owners, merchants, market participants, or regulatory authorities and meet the criteria for inclusion in MTEP as an RBP.[37]
- Other Projects – projects that do not qualify for any of the other categories and are therefore not eligible for MTEP cost allocation and will require participant funding.

The Midwest ISO has experimented with multiple transmission cost allocation methodologies. In their *pro forma* OATT filing for FERC Order 2003, the Midwest ISO acknowledged a concern with license plate pricing policies and committed to working with stakeholders to establish new policies for regional cost allocation. Subsequently in March 2004, the Midwest ISO established the Regional Expansion Criteria and Benefits (RECB) Task Force to consider regional cost sharing of certain network upgrades and new facilities. This process resulted in two filings, RECB I in 2005 and RECB II in 2006 for reliability and economic upgrades, respectively.
For its RECB I filing, the Midwest ISO proposed revisions to FERC for allocating costs of new transmission construction related to reliability and generator interconnection upgrades. Under RECB I, to qualify for any regional cost sharing, a BRP must cost $5 million or more, or the project must constitute five percent or more of the transmission owners' net plant as established in Attachment O to the Midwest ISO Tariff. Underlying principles of the RECB I process establish the potential for broad regional benefits of network projects. For example, load growth driven projects in one utility zone can benefit users in another; higher voltage projects have at least some effect on all grid users; and new generator driven transmission projects are in-part caused by the generator, but may also benefit more than just the generator or customer. Based on these principles, the FERC-accepted tariff established cost allocation for baseline reliability projects according to the following guidelines:

[37] These projects will become Market Efficiency Projects that address market efficiency economic measures more specifically, rather than economic measures more globally if FERC approves the Midwest ISO's proposed transmission planning and cost allocation changes in their July 15, 2010 filing.

- Transmission projects 345 kV and higher have 20% of project costs allocated on a system-wide basis to all transmission customers (postage stamp) and 80% allocated sub-regionally to all transmission customers in one or more zones based on a Line Outage Distribution Factor (LODF) analysis demonstrating project impacts.
- Transmission projects with a voltage greater than 100 kV but below 345 kV will have 100% of project costs allocated sub-regionally to all Transmission Customers in one or more designated zones, based on the LODF for the project.
- Generator interconnection network upgrade costs were split 50/50 between the transmission customer and the local zone, as long as there was a minimum 1-year contractual commitment to be a Midwest ISO network transmission customer. The zonal 50% share was allocated in the same manner as a baseline reliability project; the transmission customer's 50% was participant funded, or charged as a monthly fixed charge to recover Midwest ISO's transmission costs and operation and maintenance costs (O&M), at the option of transmission owner.

In its Order accepting the cost allocation process for reliability projects, FERC directed the Midwest ISO to also develop cost allocation procedures for RBPs. In November 2006, the Midwest ISO submitted a cost allocation procedure for economic projects, RECB II, which FERC conditionally accepted in March 2007. The benefits of proposed economic projects are calculated at a sub-regional level (East, Central, and West) according to the load cost savings and adjusted production cost savings for each hour.[38] The region's annual benefit is then calculated by taking the weighted average of the expected load cost saving and expected production cost saving where 70% of the benefit is the annual adjusted production cost saving and 30% of the benefit is attributed to the annual load cost saving. The calculations are made based on a minimum of 10 years of modeled benefits. In order to qualify for regional cost sharing as an RBP, a proposed economic project must satisfy two benefit tests:

- The sum of the annual benefit, the present value of the production cost benefit and the LMP-based energy cost benefit, determined in aggregate for all generation and load nodes under the Midwest ISO's tariff, must be greater than zero.
- A proposed project must satisfy a variable benefits/costs (B/C) ratio threshold, defined as the present value of the annual benefits (sum of regions') compared to the present value of annual project costs. The B/C ratio threshold varies linearly from 1.2 (for projects that have an in-service date within one year of the project's approval date) to 3.0 (for projects that have an in-service date ten or more years from the project's MTEP approval date).

[38] The Region's Load Cost Saving is the change in load energy payment (Load * Load LMP). The Region's Adjusted Production Cost Saving is the change of the Adjusted Production Cost (equals fuel costs, variable O&M costs and emissions costs) and any purchase power costs * Region Load Weighted LMP (if it purchase at that hour) - Region's Sale * Region Generation Weighted LMP (if it sales at that hour).

If the project meets three additional criteria (i.e., the project costs more than $5 million, involves facilities with voltages of 345 kV or higher, and is not considered either a baseline reliability project or new generator interconnection project), then it is a classified as a RBP under MTEP, and is eligible for regional cost allocation. Similar to the cost allocation methods for reliability, 20% of costs for economic projects are allocated on a postage-stamp basis. The remaining 80% would be allocated among three geographic sub-regions (West, Central, and East) on a license plate basis, based on a beneficiary analysis. Once each sub-region is assigned its portion of the project cost, the cost allocation to each individual entity within each geographic sub-region will be on a load ratio share basis. This methodology allows for a deviation from this cost allocation when the sum of the production cost benefit and the Locational Marginal Price (LMP) energy cost benefit to any sub-region is negative. That is, a sub-region that receives a net negative benefit from an economic upgrade is not allocated a share of the 80% sub-regional cost recovery component.[39]

With its approval of the RECB I and II cost allocation proposals, FERC required the Midwest ISO to submit reports in August 2008 and 2009 on the "effectiveness of all of the transmission unsourced quote expansion cost allocation methodologies."[40] In their status report filed with FERC on August 29, 2008, the Midwest ISO presented numerous issues related to the overall effectiveness of the transmission cost expansion methodologies and addressed some questions that were raised in the RECB II order. Specifically, the Midwest ISO raised the issue that none of the projects proposed as RBPs met the thresholds for inclusion and cost allocation. Furthermore, there has been some difficulty in characterizing projects as either reliability or economic. Economic projects are considered solely on the impacts of market efficiency as measured by locational marginal price impacts or production cost reductions. Some argued that these traditional economic impacts reflect only a portion of the benefits of a project undervaluing benefits such as supply diversity and interconnection of renewable energy projects that achieve air quality benefits.[41] Other problems identified by the Midwest ISO RECB Task Force include:

- Taken together, RECB I and RECB II further perpetuate the gray distinction between "reliability" and "economic" projects.
- Difficult to quantify reliability "benefits" are accepted rather than measured, causing stakeholders to question allocations based on postage stamp components or proximity measures.

[39] Midwest ISO, "*RECB Where Are We Now?",* Committee Meetings and Presentations, January 2009.
[40] Federal Energy Regulatory Commission, *Order Conditionally Accepting Tariff Revisions*, 118 FERC ¶ 61, 209, Docket Nos. ER06-18-004 & ER06-18-005, (FERC, March 15, 2007), http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13487362
[41] Midwest ISO, *Informational Compliance Filing of the Midwest Independent Transmission System Operator, Inc.,* Docket No. ER06-18-013, (FERC, August 29, 2008), http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13643720

- The granularity of the LODF calculation at the zonal level can cause more highly developed grid areas to see more effects and higher costs as compared to more sparsely populated zones.
- RECB treats generator interconnection-based transmission as only a reliability need and does not recognize economic or other values of the new generation additions.
- The permissible metrics for "economic" projects are too narrowly focused on congestion to capture the broader range of the potential benefits of transmission.

The report also questions whether or not the cost allocation provisions create an obstacle to the development of transmission to interconnect new wind generation projects. Through the RECB I process, the generator interconnection network upgrade costs were split 50/50 in order to provide an incentive to the generator to consider potential transmission upgrade costs when making siting decisions, and similarly, to encourage the transmission owner to minimize overall interconnection costs. However, this initial methodology was developed before large concentrations of wind generation developed in the western portion of the Midwest ISO's footprint and prior to state RPS requirements that have increased the demand for renewable energy generation. The RECB I LODF cost allocation policy would apply the costs of the network upgrade to zones located in close proximity to the wind facility where the wind power benefits may actually accrue to other zones. The Midwest ISO explained that the zones in close proximity to these types of resources would receive a disproportionate share of the network upgrade costs, even though they may not be triggering the need for them or are directly benefiting. Despite acknowledging that the current cost allocation methodologies were imperfect, the Midwest ISO did not recommend, and FERC did not require, any modifications to the RECB I and RECB II filings or resulting tariffs. Instead, the Midwest ISO committed to continue to monitor and analyze the cost sharing of transmission upgrades through its stakeholder process under RECB.

The issue of certain zones being allocated a disproportionate share of costs under the 50/50 generator interconnection cost methodology resulted in two Midwest ISO member utilities, Otter Tail Power Company and the Montana-Dakota Utilities Company, announcing that they would leave the Midwest ISO if wind development in the Dakotas led to their ratepayers being subject to cost increases from transmission development. In July 2009, the Midwest ISO and the Midwest ISO Transmission Owners submitted a filing to FERC outlining a revised method for allocating the cost of network upgrades for generator interconnection projects.[42] The revised method was put forth as a proposed interim solution to the "unanticipated and inequitable consequences" of the 50/50 cost allocation rule, until a new cost allocation methodology could

[42] Midwest Independent Transmission System Operator, Inc. and the Midwest ISO Transmission Owners, *Midwest Independent Transmission System Operator, Inc et al submits amendments to revise the method of allocating the cost of Network Upgrades etc under ER09-1431*, Docket No. ER09-1431-000 (FERC, July 9, 2009), http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12079511.

be developed through Midwest ISO's RECB stakeholder process. Under the interim cost allocation proposal:

- The cost of network upgrades for facilities rated 345 kV and above would be allocated 90% to the interconnecting generator and 10% regionally on a postage stamp basis; and
- The cost of network upgrades for facilities below 345 kV would be allocated 100% to the generator.

In October 2009, FERC conditionally accepted the proposed interim generator interconnection cost allocation methodology and directed the Midwest ISO to fulfill their commitment to creating a new cost allocation system and directed them to file the relevant tariff revisions by July 15, 2010.[43]

In December 2010, the Midwest ISO received FERC approval authorizing certain transmission planning and cost allocation revisions.[44] The Midwest ISO will create a new category of transmission projects with a corresponding cost allocation methodology, called Multi Value Projects (MVP). MVPs are projects designed to support energy policy imperatives while also providing reliability and economic benefits over multiple Midwest ISO zones. The cost of MVPs will be allocated to all load on a postage stamp basis. One of the following criteria must be met for a transmission project to qualify as an MVP:

- The project must be developed through the MTEP process for the purpose of enabling the transmission system to deliver energy reliably and economically support energy policy requirements or laws that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation; and/or
- The project must provide multiple types of economic value across multiple pricing zones with a total project benefit-to-cost ratio of 1.0 or higher. In conducting the benefit-to-cost analysis, the reduction of production costs and the associated reduction of LMP resulting from a transmission congestion relief project are not additive and are considered a single type of economic value; and/or
- The project must address at least one transmission issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based

[43] Federal Energy Regulatory Commission, *Order Conditionally Accepting Tariff Amendments And Directing Compliance Filing*, 129 FERC ¶ 61,060, Docket No. ER09-1431-000 (FERC, October 23, 2009), http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12180702.

[44] Midwest Independent Transmission System Operator, Inc. and the Midwest ISO Transmission Owners, *Entire Transmission Cost Allocation Filing*, Docket No. ER10-1791 (FERC, July 15, 2010), http://www.midwestiso.org/publish/Document/34542d_129d6210a3e_-7fbd0a48324a/Entire%20Transmission%20Cost%20Allocation%20Filing.pdf?action=download&_property=Attachment.

transmission issue that provides economic value across multiple pricing zones. In this case, the project must generate total financially quantifiable benefits in excess of the total project costs based on financial benefits and project costs.

Additionally, an MVP project must include portions that are above 100 kV and cannot be driven entirely by a generator interconnection or a transmission service request.

The Midwest ISO will leave the cost allocation methodology for generator interconnection network upgrades unchanged from the interim proposal, but multiple generator customers may share the costs of network upgrades on which they mutually rely upon, referred to as a Shared Network Upgrade (SNU). The Midwest ISO argues that the current cost allocation system for generator interconnection-related network upgrades is adequate as it will be mitigated by the new MVP and SNU facility classification system. Some network upgrades may be included as part of MVP projects and funded regionally and under SNU, network upgrades that are later found to benefit other “late comer” interconnection customers will be designated as SNUs and the original funder will be eligible to receive contributions from other generators. Network upgrades are eligible for SNU status for five years following the actual in-service date. If, within that five year window, Midwest ISO’s interconnection study process determines that a later interconnection customer benefits from the upgrade, then the upgrade will be considered an SNU. If the subsequent interconnection customer uses the SNU to a significant level, then that customer will contribute funds to cover its share of the SNU in proportion to the level of use.

The Midwest has already developed an initial MVP portfolio based primarily on options identified in the Regional Generator Outlet Study (RGOS, discussed below). A 2011 Candidate MVP Portfolio Study is under development.

Other Initiatives

The Midwest ISO initiated the /Regional Generator Outlet Study (RGOS) to develop regionally coordinated transmission projects to help meet the individual state renewable portfolio standard requirements within the Midwest ISO, with the primary focus on wind. Following on the heels of the Midwest ISO Regional Generator Outlet Study, several Midwest states joined together in September 2008, to create the Upper Midwest Transmission Development Initiative (UMTDI), a Governor-sponsored regional transmission planning effort encompassing Wisconsin, Minnesota, Iowa, and North and South Dakota established to assist the Midwest ISO. A primary function of UMTDI was to provide guidance to the Midwest ISO’s Regional Generator Outlet study on zone and transmission plan selection for study. In March 2009, UMTDI reviewed and commented on 12 indicative cost scenarios for transmission development that had been provided by the Midwest ISO under the Regional Generator Outlet Study and recommended two scenarios for further analysis. The final RGOS report was issued in November 2009 with three transmission overlay plans presenting a potential investment of $16 billion to $22 billion over the next 20 years. The RGOS report also identified some “starter projects” for potential near-term development, with a cost of about $5.8 billion.

The CapX 2020 project is an initiative of 11 transmission-owning utilities, most of which are located within the Midwest ISO, who have proposed new transmission lines to meet increasing demand and to support renewable energy expansion. The utilities proposed a series of transmission expansion projects to be placed in service from 2012 to 2014 with an estimated cost of $2.3 billion. Three of the Group I projects were included in the 2008 Midwest ISO Transmission Expansion Plan and two have been approved for cost recovery. In addition to near term reliability benefits, the CapX Group I projects described below will also provide access to generation to serve the Western Region of the Midwest ISO market, as well as delivering wind resources to the Twin Cities and to other parts of the market.

- Fargo to Twin Cities 345-kV line: a 225-mile transmission line with estimated cost of about $490 million that resolves multiple reliability issues occurring in three separate areas along the route and is eligible for cost sharing as a Baseline Reliability Project.
- Twin Cities to La Crosse 345-kV Line: a 150-mile transmission line with estimated costs of $360 million that supports the areas of Rochester, Minnesota and La Crosse Wisconsin, and is eligible for cost sharing as a Baseline Reliability Project.
- The Brookings, SD to Twin Cities 345-kV line: an estimated cost of $665 million with final route configuration pending studies currently underway by the CapX utilities and MISO in its RGOS. Nearly 7,500 MW of new wind generation could benefit from this line, enough to meet about 13% of state renewable energy standards. This project is not a Baseline Reliability Project. The cost allocation for this project has yet to be determined.

Past and Projected Transmission Investment in the Midwest ISO

There has been a lot of planning activity and many projects are being proposed, but a review of the Midwest ISO’s regional plans shows very little actual investment in economic projects, as only one has been approved as a RBP through MTEP as of the end of 2009. While the Midwest ISO has requested FERC approval for a new transmission project category, the MVP, the proposal sets some very specific conditions for approval of these projects, and it remains to be seen if it will facilitate economic transmission project approvals going forward. Figures 7 and 8 outline the past and projected reliability and economic transmission investment.

Figure 7. Cumulative Reliability-Based Transmission Investment in the Midwest ISO

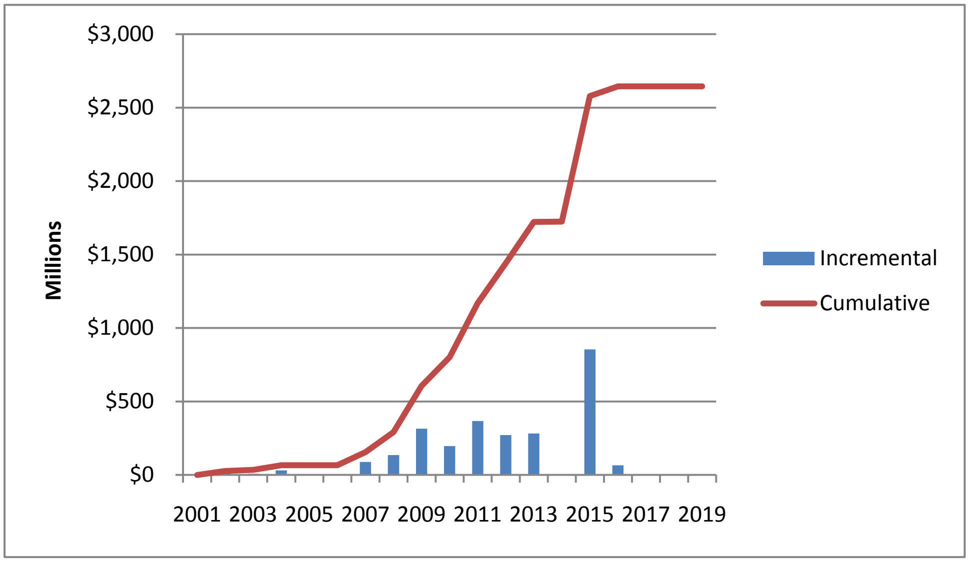
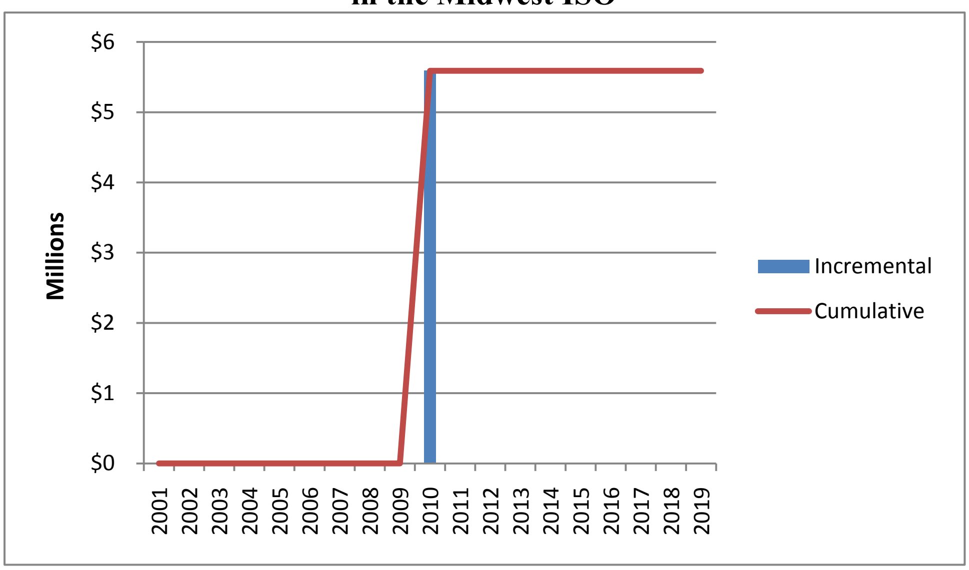


Figure 8. Cumulative Economic-Based Transmission Investment in the Midwest ISO



D. Independent System Operator of New England

The Independent System Operator of New England's (ISO-NE) annual Regional System Plan (RSP) analyzes load, resources, and transmission needs for the next ten years. Each RSP identifies a list of transmission projects that are classified as Reliability Upgrades and Market Efficiency Transmission Upgrades (METU), which are economic upgrade projects that provide a net economic benefit. Net economic benefit is defined as a reduction in total production costs to supply the system load, where the net present value of the net reduction in total production costs to serve system load exceeds the net present value of the carrying cost of the upgrade.[45] METU projects identified through the RSP are eligible for the same cost support as Reliability Upgrades.

Transmission facilities in ISO-NE are funded through a pool-wide postage stamp rate for Regional Network Service (RNS). Local transmission facilities that are determined to provide local benefits are funded through a license plate rate called the Local Network Service Rate (LNS). Under the RNS rate, the cost of a transmission project is allocated in proportion to each ISO-NE state's peak electricity demand (network load), and transmission projects that provide regional benefits are eligible for RNS cost support.[46] Reliability Upgrades and METUs rated at 115 kV and above identified in the RSP are categorized as Regional Benefit Upgrades (RBU) and funding is determined through the Transmission Cost Allocation (TCA) provisions of the ISO-NE OATT.[47] ISO-NE evaluates the RBU projects to determine what costs should receive RNS funding and what portions (if any) are localized, which are then funded through the LNS of the sponsoring zone(s). Examples of localized costs include (but are not limited to): underground transmission cables chosen to address local concerns when overhead lines would be less expensive; project costs that exceed a different transmission alternative that would serve as well; and including a covered substation when an open-air one is feasible.[48]

Smaller projects are categorized as Local Benefit Upgrades (LBU). LBUs are transmission upgrades rated below 115 kV and do not provide a regional benefit and therefore, costs are allocated through the LNS. Some higher voltage lines may also be considered LBUs if they provide no benefit outside the local area, such as (for example) single loop lines that do not allow two-way power flow. ISO-NE's generator interconnection procedures allocate the cost of network upgrades to the generator (reimbursed later as per Order 2003) but does contain a provision for regional cost sharing, where if ISO-NE determines the upgrade triggered by the

[45] ISO New England Inc., *2008 Regional System Plan*, October 16, 2008, http://www.iso-ne.com/trans/rsp/2008/rsp08_final_101608_public_version.pdf.
[46] ISO New England, *ISO New England Planning Procedure No. 4: Procedure for Pool-Supported PTF Cost Review,* Effective Date January 5, 2007.
[47] Other projects eligible for TCA are grandfathered projects identified as upgrades from ISO-NE's previous planning process and projects considered as reconstruction or replacement of existing pool transmission facilities.
[48] ISO New England, *ISO New England Planning Procedure No. 4: Procedure for Pool-Supported PTF Cost Review,* Effective Date January 5, 2007.

interconnection request provides benefits to the system as a whole, then ISO-NE will allocate costs through the TCA.[49] Transmission owners (or other parties sponsoring the project) that want a specific project considered for funding under TCA can submit a TCA application.

In response to Order 890, ISO-NE included an Economic Studies process into Attachment K, which allows stakeholders to submit requests for projects to be considered in up to three annual Economic Studies. The Economic Studies allow stakeholders to review the impact of proposed system expansions or resource alternatives that would be considered as an extension to the RSP. Requests for Economic Studies must be submitted by April 1st of each year and by June 1st, ISO-NE will meet with stakeholders to create up to three different Economic Studies scenarios to be performed.

The Economic Studies are designed to provide information to stakeholders and include economic evaluations, environmental emissions analysis, and the potential benefits of relieving certain transmission constraints and developing resources in alternative locations. The results can then be used by developers to plan for potential projects and propose "Merchant and Elective Transmission Upgrades" as inputs to the RSP. More targeted studies may be used as input to an METU. ISO-NE will perform a Needs Assessment for any projects seeking classification as an METU. The criteria used for the needs assessment is as follows:

- Does the alternative solution result in a net reduction of total production cost to supply system load, after considering the cost of the project;
- Does the alternative solution result in less congestion; or
- Does the alternative solution allow the integration of new resources and load on an aggregate regional basis.[50]

ISO-NE reported that the 2008 Economic Studies cycle showed congestion under some scenarios with new generating resources in remote areas, but that METUs were not warranted. The production cost studies conducted for the 2008 RSP scenario exhibited resource and transmission system adequacy and resulted in no apparent congestion through 2018.[51]

The New England Governors' Conference (NEGC) has been actively involved in regional renewable energy development. In September 2008, Governor Baldacci, Chair of the NEGC, established the Bar Harbor Energy Working Group and directed it to develop a policy and analytical framework for expanding energy trade throughout region, which ultimately resulted in

[49] ISO New England, *ISO New England Inc. Transmission, Markets and Services Tariff: Schedule 22, Standard Large Generator Interconnection Procedures (LGIP)*, http://www.iso-ne.com/regulatory/tariff/sect_2/sch22/index.html (accessed March 30, 2009).
[50] ISO New England, Inc., *Stakeholder Economic Study Requests and ISO Proposed Scope of Work*, Presentation at IPSAC Meeting, June 30, 2009.
[51] Ibid.

the *New England Governors' Renewable Energy Blueprint*.[52] In March 2009, a formal request was issued through the New England States Committee on Electricity (NESCOE) for ISO-NE to conduct an Economic Study for the renewable development scenarios under consideration for the Blueprint. In February 2010, ISO-NE released the economic study, titled *New England 2030 Power System Study*.[53] The economic study conducted scenario analysis for renewable energy development (primarily wind), developed potential transmission configurations to access the renewable energy resources, and estimated the cost for constructing the transmission (see Table 2).

[52] New England Governors' Conference, Inc., *New England Governors' Renewable Energy Blueprint*, September 15, 2009, http://www.negc.org/documents/2009/Renewable_Energy.pdf.
[53] ISO New England, Inc., *New England 2030 Power System Study: 2009 Economic Study: Scenario Analysis of Renewable Resource Development*, Report to the New England Governors, February 2010, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/economicstudyreportfinal_022610.pdf.

Table 2: Summary of ISO-NE Scenarios for Renewable Resources

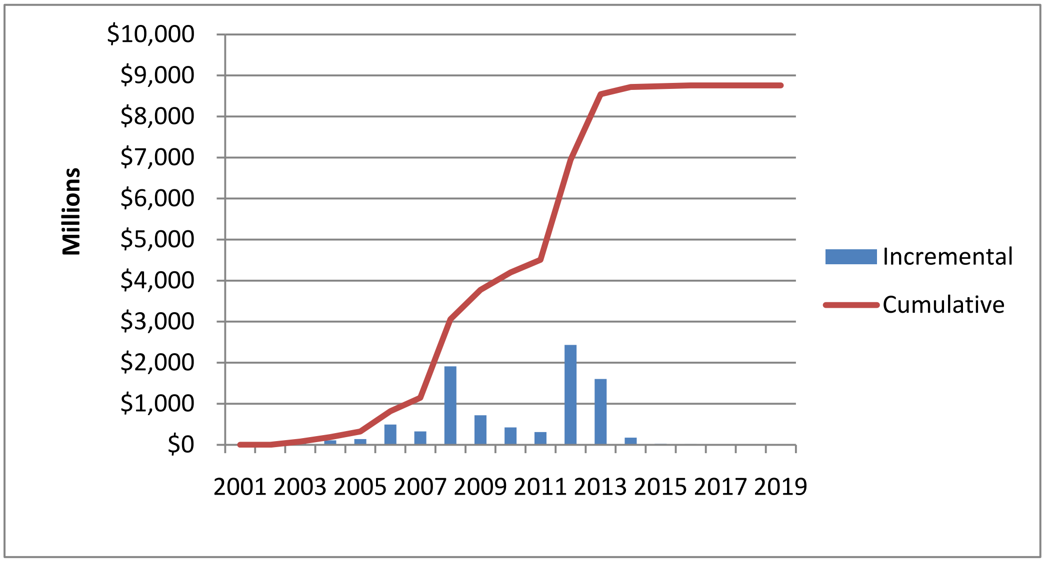
Case	New Capacity (MW)	Percent of New England Energy	Approx. Circuit Miles of New Transmission	Preliminary Order-of-Magnitude Cost-Estimate Range by Voltage Class (billions of 2009 $)	Midrange Cost Estimate (billions of 2009 $)
New England Wind **1,000 MW inland; 1,000 MW offshore**	2,000	4.7	1,785	345 kV/HVDC: $4.7 to $7.9	$6.4
New England Wind **Offshore only**	2,000	5.1	1,015	345 kV/HVDC: $3.6 to $6.0	$4.8
New England Wind **2,000 MW inland; 2,000 MW offshore**	4,000	8.4	3,615	345 kV: $8.0 to $13.2 500 kV: $10.8 to $17.9	$10.7 $14.3
New England Wind **Offshore only**	4,000	9.3	1,430	345 kV/HVDC: $4.7 to $7.6	$6.1
New England Wind **1,500 MW inland (near the coast); 4,000 MW offshore**	5,500	12.4	1,430	345 kV/HVDC: $4.7 to $7.6	$6.1
New England Wind **4,000 MW inland; 4,000 MW offshore**	8,000	15.9	4,320	500 kV: $13.4 to $22.4 765 kV: $17.3 to $28.9	$17.9 $23.0
New England Wind **7,500 MW inland; 4,500 MW offshore**	12,000	22.8	4,320	500 kV: $14.5 to $24.2 765 kV: $18.9 to $31.5	$19.3 $25.2
New Brunswick Interchange	1,500	10.7	400[(a)]	+/-450 kV HVDC: $1.5 to $2.5B[(a)]	$2.0B[(a)]
Québec Interchange	1,500	11.2	280[(a)]	+/-450 kV HVDC: $1.1 to $1.9[(a)]	$1.6B[(a)]
New England & Eastern Canadian Wind **5,500 MW New England** *plus* **3,000 MW New Brunswick & Québec**	8,500	14.7	2,110[(a)]	$4.7 to $7.6 New England Wind *plus* $2.6 to $4.4 New Brunswick & Québec Interchange[(a)] Total: ~$7 to ~$12	N/A
New England & Eastern Canadian Wind **12,000 MW New England** *plus* **3,000 MW New Brunswick & Québec**	15,000	26.1	5,000[(a)]	$14.5 - $31.5 New England Wind *plus* $2.6 to $4.4 New Brunswick & Québec Interchange[(a)] Total: ~$17 to ~$36	N/A

(a) Circuit miles and estimated costs are only for facilities located in New England.

Source: ISO New England, Inc., *New England 2030 Power System Study, Report to the New England Governors, 2009 Economic Study: Scenario Analysis of Renewable Resource Development*, February 2010.

The METU has been a part of ISO-NE's planning process for several years, but to date, no METU projects have been approved and constructed. A review of recent transmission plans shows no future METU projects upcoming. It remains to be seen if the Economic Studies process will lead to any economic transmission projects in the future. Figure 9 shows the past and projected spending on reliability projects in ISO-NE.

Figure 9. Cumulative Reliability-Based Transmission Investment in ISO-NE



E. PJM Interconnection

PJM's annually produced Regional Transmission Expansion Plan (RTEP) consists of potential transmission projects arising from four planning areas: reliability, economic, transmission interconnection, and local planning.[54] PJM conducts reliability and economic planning for facilities designated as Bulk Electric System (BES) facilities and other designated facilities, including all transmission lines rated 100 kV and above. PJM also conducts planning and analysis on facilities rated below 100 kV if those facilities are under direct PJM control, i.e. not part of an individual transmission owner's system. Transmission interconnection planning arises from generator interconnection requests, merchant transmission interconnection requests, and requests for long-term firm transmission service. Local planning is initiated by individual transmission owners on transmission owner operated facilities less than 100 kV, as part of PJM's sub-regional RTEP process.

The RTEP consists of a single plan that results from the evaluation of the system over a planning horizon extending through 15 years. The plan consists of transmission projects determined as required to meet forecasted load, new generation interconnection projects and merchant transmission projects throughout the planning horizon based on NERC, PJM, and local reliability, market efficiency, and operational performance requirements.

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[54] PJM Interconnection Planning Division Transmission Planning Department, *PJM Manual 14B: PJM Regional Transmission Planning Process*, Revision 12, Effective October 8, 2008, http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

Costs for constructing transmission facilities in PJM are based on the capacity of the line and the estimated total cost of the project. Transmission lines rated at 500 kV and above (both reliability and economic upgrades) are considered regional facilities and are currently funded through postage-stamp rates where costs are assigned region-wide on an annual load-ratio share basis.[55] This methodology was challenged in a court case by utilities in the Midwestern part of PJM. In August 2009, the U. S. Court of Appeals for the 7th Circuit ruled that the postage stamp method was not adequately supported, and remanded it back to FERC for reconsideration.

For baseline reliability upgrade projects rated below 500 kV, PJM's cost allocation methodology is as follows:[56]

- Projects costing $5 million or less – the cost is allocated to the zone the project is located in.
- Projects costing more than $5 million – costs are allocated to the relevant market participants (typically load) according to their relative contribution to the reliability violation that is being addressed by the project, as determined by PJM's modeling.

Interconnection costs in PJM, both generator and merchant transmission, are borne in full by the project proponents, with reimbursement for network upgrades as per Order 2003.

In response to Order 890, PJM clarified and revised the RTEP Market Efficiency Planning process, primarily to address cost allocation issues and define the benefit/cost methodology. PJM's market efficiency analysis assesses the economic impact of the major backbone upgrades identified in the annual RTEP process.

Following the baseline reliability planning analysis, PJM evaluates the economic merits of the proposed transmission projects. The economic analysis focuses on impacts to load costs and production costs and is intended to accomplish the following objectives:

- Determine which reliability upgrades, if any, have an economic benefit if accelerated or modified. Modifications would involve intentionally designing a transmission project in a more robust manner (for example, at a higher voltage level) to provide economic benefits in addition to the reliability issues.[57]
- Identify new transmission upgrades that may result in economic benefits.

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[55] Included as regional facilities are any lower-voltage supporting facilities that are a part of the relevant transmission project and needed to directly support integration of the high-voltage lines.
[56] PJM Interconnection, *PJM Open Access Transmission Tariff*, last revised October 7, 2008, http://www.pjm.com/~/media/documents/agreements/tariff.ashx.
[57] PJM Interconnection, *PJM 2008 Regional Transmission Expansion Plan*, 7, February 27, 2009, http://www.pjm.com/documents/reports/rtep-report/~/media/documents/reports/2008-rtep/2008-rtep-report.ashx.

PJM considers the following factors when determining if an economic benefit can be derived from a given project:

- Total production costs, load payments, and generator revenues.
- Zonal load payments and zonal Financial Transmission Rights credits plus additional Auction Revenue Rights that arise from the proposed project.
- Total transmission system losses.
- Total Reliability Pricing Model capacity payments.[58]

These metrics apply both to new economic transmission upgrades and for determining whether an additional economic benefit can be derived by accelerating or modifying a reliability upgrade. PJM calculates a present value benefit/cost ratio, where the benefit is weighted as follows: (0.7*change in production costs)+(0.3*change in load energy payments). The benefit/cost ratio must be at least 1.25 over the first 15 years of the project to be considered economic and included in PJM's RTEP.[59]

Economic projects rated 500 kV and above are also considered regional facilities and will be funded the same way as reliability projects. For economic upgrades rated below 500 kV, the costs are allocated to the affected zones as determined by a settlement agreement approved by FERC on July 29, 2008:

- For economic transmission modifications and accelerations of reliability upgrades, costs are assigned on a beneficiary pays basis. PJM uses a Distribution Factor (DFAX) analysis to determine beneficiaries and to assign cost responsibility.[60] For project modifications the DFAX calculation is used. For accelerated projects, cost allocation will be decided by performing the following:
    - PJM will conduct a DFAX analysis for the period during the acceleration of the transmission project, and a proxy for an LMP benefits calculation based on reduction in LMP payments made by load serving entities because of the acceleration.
    - To allocate costs, if the DFAX results and LMP results differ by 10% or more, cost responsibility assignment is based on the LMP method; conversely, if the

[58] PJM Interconnection Planning Division Transmission Planning Department, *Manual 14B: PJM Regional Transmission Planning Process*, Revision 15, Effective April 21, 2010, http://www.pjm.com/~/media/documents/manuals/m14b.ashx.
[59] PJM Interconnection, *Overview of PJM Economic Planning Process Market Efficiency Analysis*, Presentation at IPSAC Meeting, June 30, 2009, slides, http://www.interiso.com/public/meeting/20090630/20090630_pjmecon.pdf.
[60] Beneficiary distribution factors are percentages which represent the portions of a transfer of energy from a defined source to a defined sink over that particular transmission facility(s). DFAX represents the measure of the effect of each specified load on the transmission constraint the upgrade alleviates.

results for all zones differ by less than 10%, cost responsibility assignment is based on the DFAX method.

- Economic-based transmission upgrades are new enhancements or expansions that could relieve an economic constraint(s) but for which no reliability-based need has been identified. On July 28, 2009, PJM submitted a filing proposing a funding methodology for economic-based projects below 500 kV.[61] This was subsequently approved by FERC in September 2009. Under this methodology, cost responsibilities will be assigned based on Change in Load Energy Payment. Specifically, the cost will be allocated on a pro rata share to each zone that shows a decrease in the load energy payments.

Past and Projected Transmission Investment in PJM

No economic-based projects or acceleration of reliability upgrades for economic reasons were identified in the 2008 RTEP due to three proposed backbone transmission projects that have been classified as reliability upgrades. These 500-kV high-voltage projects, the Mid-Atlantic Power Path, Potomac-Appalachian Transmission Highline, and Trans-Allegheny Interstate Line, were expected to address the majority of PJM's congestion and reliability issues. The need and timing of these projects and alternative projects are continually reevaluated in PJM's annual planning process. In addition, the cost responsibility is subject to an on-going regulatory process. The projects, however, continue to proceed as planned. The 2009 RTEP identified one small economically driven transmission upgrade project: the addition of a 500/230-kV transformer at Conemaugh in Western Pennsylvania coupled with a new 230-kV line between Conemaugh and Seward. This project was approved by the PJM Board in February 2010. Figures 10 and 11 outline the past and projected reliability and economic transmission investment in PJM.

[61] PJM Interconnection, Docket Nos. ER06-456-013, ER06-954-009, ER06-1271-008, ER07-424-004, EL07-54-000 and 002 (consolidated), PJM Transmission Owners, Docket Nos. ER06-880-000, -003 and -010 (Consolidated), (FERC, July 28, 2009).

Figure 10. Cumulative Reliability-Based Transmission Investment in PJM

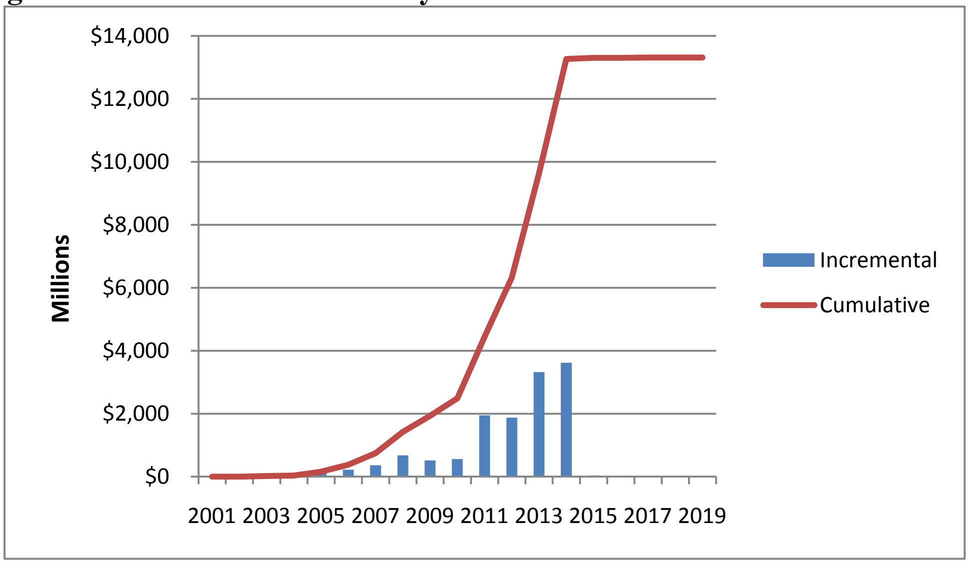
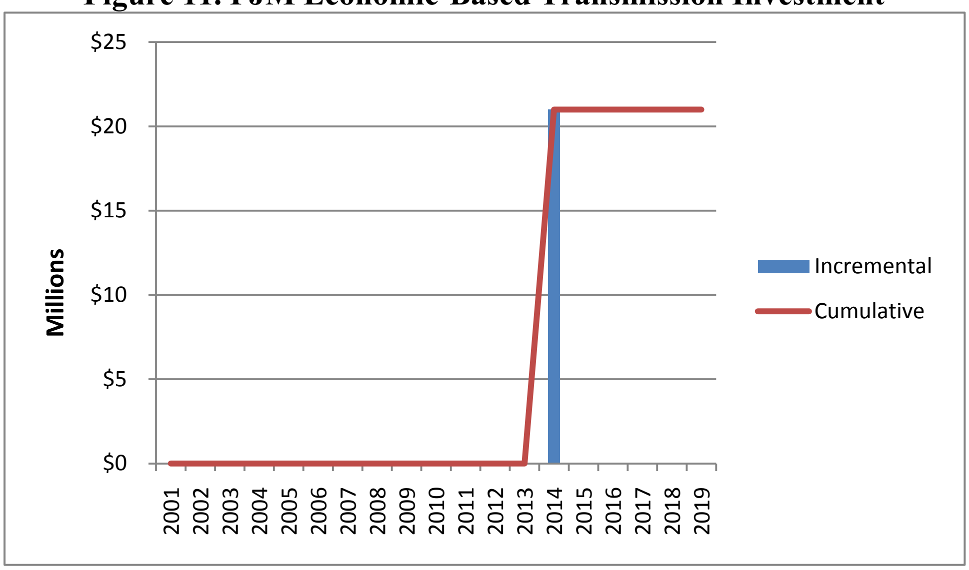


Figure 11. PJM Economic-Based Transmission Investment



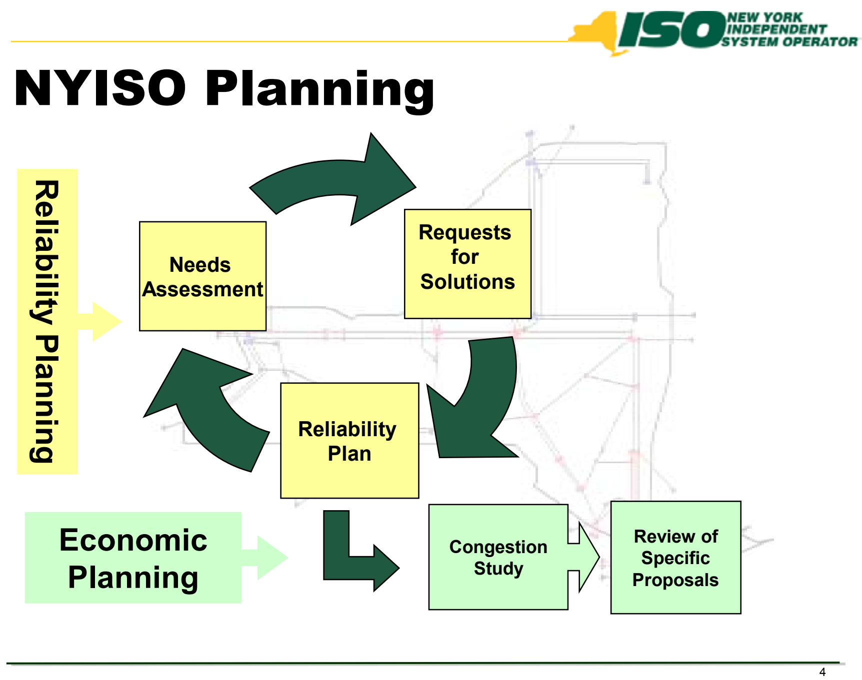
F. New York Independent System Operator

The New York Independent System Operator (NYISO) employs a market-based philosophy in the design of its wholesale markets and in its transmission planning process. While the NYISO gives preference to market-based projects, there are provisions for regulated backstop projects to meet reliability needs in the event that market-based solutions are inadequate. The NYISO also follows a strict beneficiary pays system. For each project, the NYISO identifies the zones that are contributing to the reliability violation that the project will alleviate. The project costs are allocated to those zones according to their contribution to the reliability violation.

In response to FERC Order 890, the NYISO enhanced its planning process to include a local transmission owner planning component and an economic planning component. In October 2008, FERC conditionally accepted the NYISO's initial filing outlining the planning process additions.

The Comprehensive System Planning Process (CSPP) is a biennial three stage process covering local transmission planning, reliability planning, and economic planning (see Figure 12).[62]

Figure 12. NYISO Comprehensive System Planning Process



Source: Bill Lamanna, *NYISO Economic Planning Process*, NYISO Presentation at the IPSAC Meeting, Newark, New Jersey, June 30, 2009, Draft Slides, p.4, http://www.interiso.com/public/meeting/20090630/20090630_nyisoecon.pdf.

Phase 1: Local Transmission Owner Planning Process (LTPP)

The planning process begins with each New York Transmission Owner (NYTO) developing a Local Transmission Plan (LTP) based on the reliability needs of their particular service territory. In keeping with Order 890 requirements, each NYTO is required to provide opportunities for stakeholders to provide input into the LTP.

[62] Federal Energy Regulatory Commission, *Order on Compliance Filing*, New York Independent System Operator, Inc., Docket Nos. OA08-52-000, OA08-52-001, OA08-52-002 (FERC, October 16, 2008).

Phase 2: Comprehensive Reliability Planning Process (CRPP)

Following completion of the LTPs, the NYISO then uses them as input into the CRPP. The CRPP is a 10-year long-range assessment of resource adequacy and transmission reliability for the New York bulk power transmission system. The CRPP considers transmission, generation, and demand response on a comparable basis. The CRPP begins with a Reliability Needs Assessment (RNA), which evaluates the adequacy and security of the bulk power system over the next 10 years. In the RNA, the NYISO identifies the amount of resources (called 'compensatory MWs') needed to satisfy reliability criteria, and the general locations where those resources are needed. The NYISO then designates one or more relevant Responsible Transmission Owners to prepare proposal and, if required, be responsible for developing regulated backstop solutions to address designated reliability needs. Once the RNA has identified the amount and location of needed resources, the NYISO also makes a request for market-based and alternative regulated solutions that may be submitted by any qualified developer. The solutions do not have to be in the particular amounts or locations as outlined in the RNA, as there are various combinations of resources and transmission upgrades that could meet the identified reliability needs. Following its analysis of all proposed solutions, the NYISO determines whether there are sufficient market-based solutions to meet the reliability needs identified in the RNA. If reliability issues remain following the incorporation of the market-based solutions, then the NYISO will direct the Responsible Transmission Owner(s) to initiate regulated backstop solutions, as required, to fully meet reliability needs. Finally, the NYISO reports its plan for meeting the reliability needs of the New York grid in a Comprehensive Reliability Plan (CRP), which is approved by the NYISO Board of Directors following an extensive stakeholder review.

Phase 3: Congestion Analysis and Resource Integration Studies (CARIS)

The Congestion Analysis and Resource Integration Studies (CARIS) phase begins after completion of the CRP. The CARIS uses the CRP as a base case which provides a reliable system through the ten-year planning horizon on which to conduct its economic analysis. As with the CRPP, the CARIS will consider all resources on a comparable basis. The CARIS is conducted in two stages:

(1) Study Stage −

The study stage begins with a congestion assessment, which includes historic congestion and a ten-year congestion forecast based on projected load growth. The NYISO identifies the three most congested paths/elements based upon the change in bid production costs that result from transmission congestion. Three potential generic solutions (representing generation, demand response, and transmission) are then selected to address each of the congested paths and are agreed to by stakeholders for a cost-benefit analysis. The cost-benefit analysis also includes measures of the impact of the potential solutions on load payments and generator payments, and hedged and unhedged congestion payments. Any stakeholder can request additional studies on different potential solutions but must provide the funding for the study. The NYISO then issues a CARIS report, which provides the results of its analysis to assist developers and other stakeholders in the development of their business strategies.

(2) Specific Project Evaluation Stage −

The NYISO then makes a request for specific projects to be proposed to meet the CARIS report solutions. The NYISO will then conduct cost/benefit analysis on each of the proposed projects. Along with the cost/benefit analysis, the NYISO will also determine who the beneficiaries are for each project and issue a Cost Allocation Report.

The NYISO has separate policies for allocating the costs of reliability-based and economic transmission projects. Both policies however, follow a strict beneficiary pays principle. Allocation of costs arising from reliability needs is based on a three-step approach that determines if the need is locational, statewide, or within a bounded region.

Step 1 focuses on those areas within the NYISO that have identified locational capacity requirements, which currently includes only New York City and Long Island. If a reliability upgrade is needed to satisfy a reliability issue local to New York City or Long Island, then the cost of the project is allocated to the load serving entities in that zone.

Step 2 focuses on regional reliability projects. The NYISO runs a simulation model of the entire region using a 'free flow method,' where all internal transmission constraints have been relaxed. The NYISO uses this model to determine if an unconstrained NYISO control area would have a Loss-of-Load-Expectation (LOLE) of less than 0.1 days per year. If not, then the costs of the reliability projects needed to reach this threshold are allocated to all zones based on their peak load contribution, with the zones from Step 1 receiving offset credit for the upgrades they have already funded.

Step 3 is only applied if step 2 meets the LOLE threshold and hence, no projects were activated. In this step, the NYISO applies the binding interface test, where binding transmission constraints that prevent sufficient generating capacity from being delivered throughout the NYISO are identified and compensated for through an iterative process of adding resources to the bounded zones with the most impact on reducing the LOLE. Once the iterative process has identified where resources need to be, the costs are allocated to the bounded zone where each project was required in order to compensate for a constraint. [63]

[63] Federal Energy Regulatory Commission, *Order on Compliance Filing*, New York Independent System Operator, Inc., Docket Nos. OA08-52-000, OA08-52-001, OA08-52-002 (FERC, October 16, 2008).

For a proposed economic transmission project to be eligible for regulated cost recovery under the NYISO Tariff, it must meet the following conditions:

- The benefit of the proposed project must exceed the cost. The benefit is defined as the present value of annual NYISO-wide production cost savings and the cost is the present value of the project's annual total revenue requirement, both over the first ten years the project will be in service.
- The total capital cost of the project must exceed $25 million.
- Eighty percent (referred to as a supermajority) of the project beneficiaries must support the project by voting for it in the stakeholder process.[64]

If a project meets the eligibility requirements, the NYISO will identify the project's beneficiaries over the first ten years the project will be in service. Beneficiaries are identified by measuring the present value of annual LMP savings for load in the zones affected by the project, net of reductions in transmission congestion credit payments and the price of bilateral contracts. For each load zone that experiences a benefit, a portion of the project cost is allocated based on their pro rata share of the total savings. Within each zone, the zonal cost is allocated to each load serving entity based on its historic megawatt-hour (MWh) share of consumption.

The NYISO released its *2009 Reliability Needs Assessment* on January 13, 2009. The 2009 RNA concluded there were no reliability needs in the NYISO control area from 2009 through 2018, and therefore, the NYISO did not request any solutions for that year.[65] The *2009 Comprehensive Reliability Plan*, released May 19, 2009, reiterated that no reliability solutions are necessary over the ten-year planning horizon and recommended that NYISO continue to monitor already ongoing projects. Additionally, the 2010 RNA, currently in draft form, has found no reliability needs through the year 2010. It is expected that the 2010 RNA will be issued in September.[66]

On January 12, 2010, the NYISO published its first economic planning report, the *2009 Congestion Assessment and Resource Integration Study* (CARIS – Phase 1).[67] The Phase 1 report includes NYISO's assessment of historic and future congestion on the New York grid and analysis of the potential benefits and costs of relieving that congestion, either through additional transmission, generation, or demand response resources. The CARIS Phase 1 study identified three

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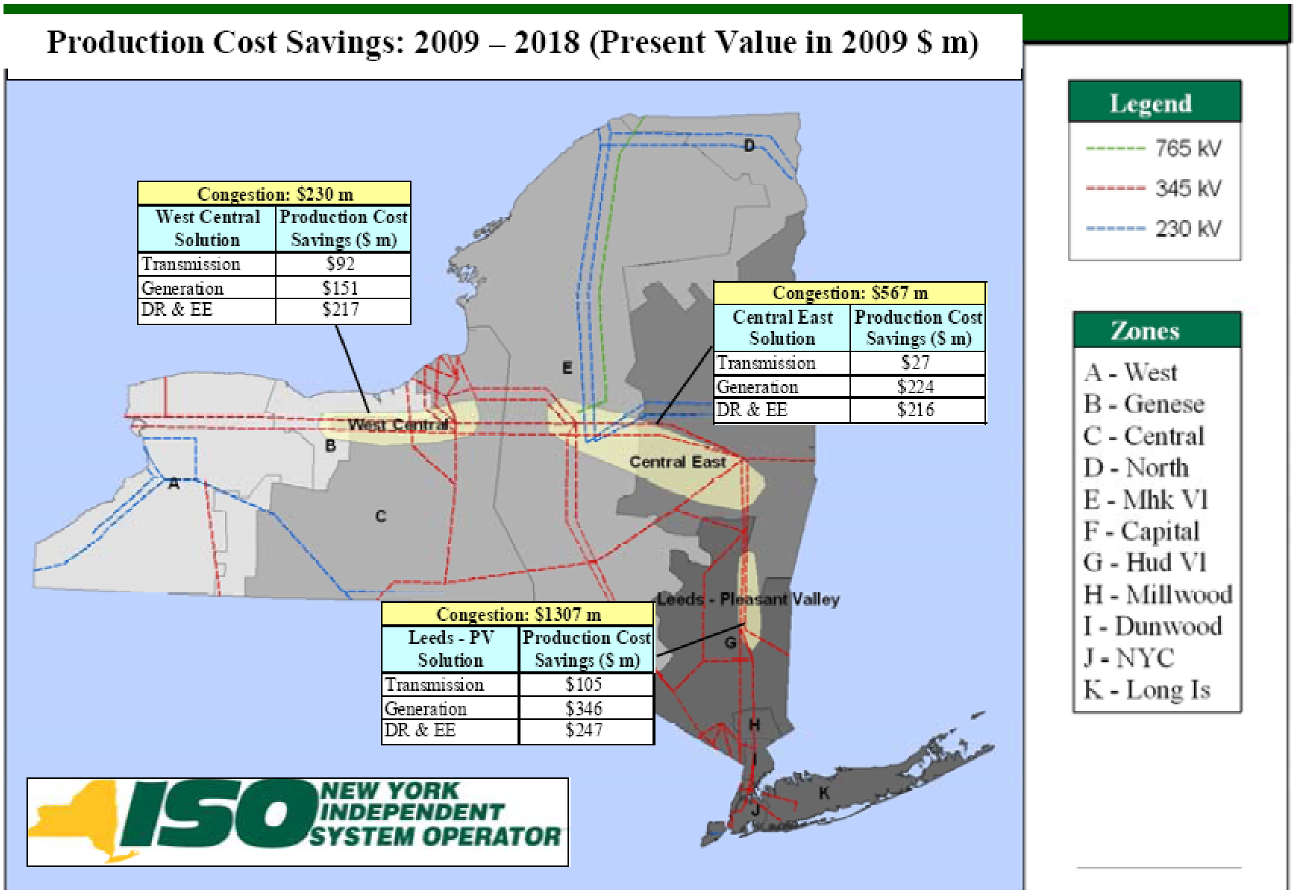
[64] Federal Energy Regulatory Commission, *Order on Rehearing*, 126 FERC ¶ 61,320, Docket No. OA08-52-003 (FERC, March 31, 2009), http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=11979625.
[65] NYISO, *2009 Reliability Needs Assessment: Comprehensive System Planning Process, Final Report*, January 13, 2009, http://www.nyiso.com/public/webdocs/newsroom/press_releases/2009/RNA_2009_Final_1_13_09.pdf.
[66] Communications with NYISO personnel, August 12, 2010.
[67] NYISO, *2009 Congestion Assessment and Resource Integration Study: Comprehensive System Planning Process, CARIS – Phase 1*, January 12, 2010, http://www.nyiso.com/public/webdocs/services/planning/Caris_Report_Final/CARIS_Final_Report_1-19-10.pdf.

congested areas on the New York grid – Leeds-Pleasant Valley, Central Ease, and West Central – and presented production cost savings for each generic solution, as shown in Figure 13 below.

Figure 13. NYISO CARIS Results: Generic Solutions



Source: NYISO, *2009 Congestion Assessment and Resource Integration Study: Comprehensive System Planning Process, CARIS – Phase 1*, January 12, 2010, p.iv, http://www.nyiso.com/public/webdocs/services/planning/Caris_Report_Final/CARIS_Final_Report_1-19-10.pdf.

In Phase 2, NYISO will accept proposals for economic transmission projects and will evaluate their potential to relieve congestion and provide economic benefits as defined in the CARIS process. Developers may also use the information in the Phase 1 report to determine whether they wish to pursue generation and/or demand response projects within the identified areas.

G. Electric Reliability Council of Texas

The Electric Reliability Council of Texas (ERCOT) is contained wholly within Texas with minimal connection to other transmission grids outside of Texas. Therefore, ERCOT is not regulated by FERC other than on issues arising from the Energy Policy Act of 2005. The

ERCOT planning process is a system-wide assessment of both reliability and economic transmission projects. Economic projects must pass the additional hurdle of being expected to allow incrementally lower system-wide production costs to offset the cost of the transmission project. However, there is no difference in the cost recovery mechanism between the reliability and economic transmission projects. ERCOT coordinates the regional planning process for all transmission upgrades. The Public Utility Commission of Texas (PUCT) must approve all new transmission lines. The PUCT has designated transmission development as a social good and all costs are delegated to load through postage-stamp rates. A Regional Planning Group (RPG) comprised of stakeholders, market participants, and other interested parties review and provide feedback on potential transmission projects, as well as propose transmission projects for consideration. ERCOT assesses all generation and transmission additions through its Regional Planning Group Charter and Procedures, including all feedback from the RPG, with the resulting projects then passed to the PUCT for approval.

Texas Competitive Renewable Energy Zone Initiative

In January 2007, the Texas RPS was revised to include the creation and development of Competitive Renewable Energy Zones (CREZ), designated areas with large wind generation potential that lack adequate transmission.[68] In April 2008, ERCOT released the CREZ Transmission Optimization Study that identified and quantified transmission costs for four different CREZ development scenarios as previously chosen by the PUCT.[69] The cost estimates for the transmission plans ranged from $2.95 billion to $6.38 billion. In July 2008, the PUCT granted preliminary approval for developing Scenario 2, which will cost approximately $4.93 billion for the transmission lines and $580-$820 million for the collector system to gather the wind power. The scenario includes 2,334 miles of new 345-kV transmission lines and 42 miles of new 138-kV transmission lines to move up to 18,456 MW of wind power from the Texas Panhandle to Dallas and Fort Worth; from Central-west Texas and Abilene to Dallas, Austin, and San Antonio; and from McCamey to Austin and San Antonio.

The PUCT awarded the development of CREZ transmission plan segments to the following entities: AEP Texas Central Company (AEP TCC), AEP Texas North Company (AEP TNC), Bandera Electric Cooperative, Brazos Power Electric Cooperative, CenterPoint Energy Houston Electric, Garland Electric Utilities, Texas Municipal Power Agency (TMPA), Lower Colorado River Authority (LCRA), Oncor Electric Delivery Company, Cross Texas Transmission, Electric

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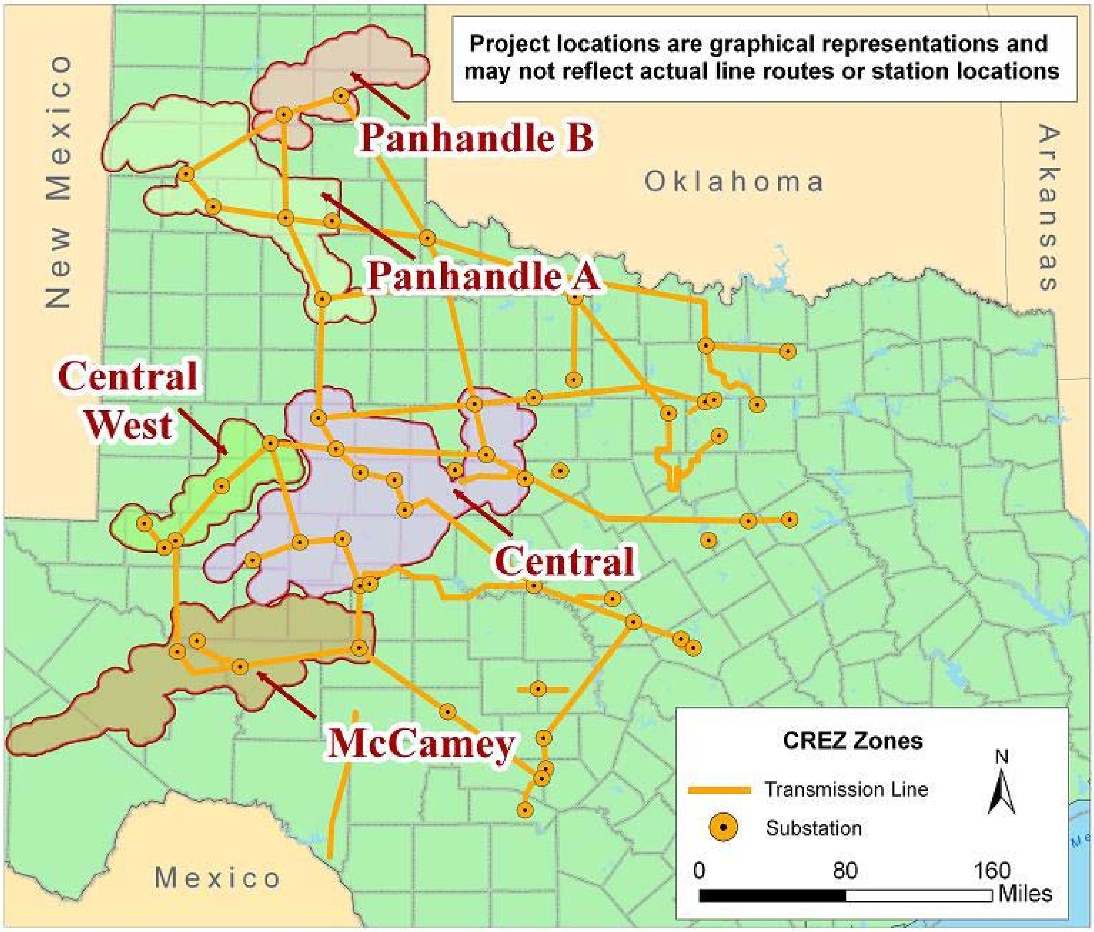
[68] Public Utility Commission of Texas, "Public Utility Regulatory Act: Competitive Renewable Energy Zones", Chapter 25, Subchapter H, Division 1, Section 25.174, http://www.puc.state.tx.us/rules/subrules/electric/25.174/25.174.pdf

[69] Dan Woodfin, *CREZ Transmission Optimization Study Summary*, ERCOT Presentation to the ERCOT Board of Directors, April 15, 2008, http://www.ercot.com/meetings/board/keydocs/2008/B0415/Item_6_-_CREZ_Transmission_Report_to_PUC_-_Woodfin_Bojorquez.pdf;
Scenarios 1a & 1b would have supported up to 12,053 MW of wind capacity, Scenario 3 would have supported up to 24,859 MW, and Scenario 4 would have supported up to 24,419 MW.

Transmission Texas (ETT), Lone Star Transmission, Sharyland Utilities, South Texas Electric Cooperative (STEC), and Wind Energy Transmission Texas (WETT) (see Figure 14).[70]

Figure 14. CREZ Transmission Plan Projects



Source: Public Utility Commission of Texas, CREZ Transmission Program Information Center: CREZ Zones, http://www.texascrezprojects.com/overview.aspx.

Each of the new lines will require a Certificate of Convenience and Necessity (CCN), designating the routing of the line, to be issued by the PUCT to the utility that is constructing the line. The PUCT has scheduled filing dates for each of these CCN cases during 2010 and 2011; some of these CCN cases have already been completed and others are on-going. The PUCT has also created a website that provides current information about the status of each project.[71]

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[70] Public Utility Commission of Texas, *Order, Commission Staff's Petition for Selection of Entities Responsible for Transmission Improvements Necessary to Deliver Renewable Energy from Competitive Renewable Energy Zones*, Docket No. 35665 (March 30, 2009).

[71] Public Utility Commission of Texas, CREZ Transmission Program Information Center, http://www.texascrezprojects.com/default.aspx.

IV. Examples of Non RTO/ISO Economic Planning and Cost Allocation Initiatives

An 'open season' for transmission service involves transmission customers subscribing to take transmission service on a proposed project in advance. Open seasons are based on similar procedures used to pre-subscribe natural gas lines where the subscribers receive priority transmission rights in exchange for making the purchase upfront. This has also been called the 'anchor-tenant' model where, the anchor customers provide advance funding for transmission development and in turn are guaranteed transmission access for their generation projects.

Bonneville Power Administration Network Open Season

In 2008, BPA implemented a network open season process for transmission service requests, as BPA's transmission request queue had become overloaded (316 requests for 14,464 MW) and BPA was having difficulties processing the volume of requests. Many of the transmission service requests in the BPA queue were speculative or duplicative, with a single 100-MW project sometimes accounting for up to 500 MW in the transmission service queue. As a result, some customers with an immediate need for transmission service were blocked by transmission service requests higher up in the transmission queue.

BPA had tried an open season approach before in 2004 for the proposed McNary-John Day transmission path in Oregon/Washington, but it failed to get enough advance commitment and the project was shelved. A convergence of events persuaded BPA to make a second attempt at an open season:

- The congested long-term firm transmission queue for new transmission service on BPA's network coupled with an inability under the pro forma OATT to process the requests in a timely manner.
- The establishment of renewable portfolio standards in California, Oregon, Washington, and Montana that are driving the growth of wind energy.
- The BPA transmission grid, in its current state, could not accommodate projected future transmission usage without new transmission.
- No coordinated regional transmission planning is in place to define future transmission requirements.[72]

Under the Network Open Season (NOS) process, BPA holds month-long open seasons annually where entities can submit applications to BPA via a precedent transmission service agreement

[72] National Wind Coordinating Collaborative, *NWCC Transmission Update: Bonneville Power Administration's Network Open Season & Anchor Tenant Model for TransCanada's Chinook and Zephyr Transmission Lines*, May 2009, http://www.nationalwind.org/assets/publications/NWCCTransmissionUpdateMay09.pdf.

(PTSA). BPA requires those with a long-term transmission service request to sign a PTSA and provide a refundable deposit equal to 12 months of transmission service; otherwise the request is removed from BPA's transmission service queue. BPA then conducts a comprehensive cluster study and determines what new transmission facilities, if any, are necessary to provide service to the signed PTSAs. Next BPA performs a financial analysis to determine if there is sufficient commitment to move forward at BPA's embedded cost rates.[73] For proposed projects that meet these requirements, BPA will fund the costs of the National Environmental Policy Act environmental studies, and eventually the construction of the facilities. BPA's NOS process essentially changes the order of the steps in pro forma FERC OATT, as well as the "business arrangements" contained therein, as customers must first sign the PTSA committing to take transmission service if BPA meets its PTSA-specified milestones and provide a deposit before the studies are conducted.

In the 2008 NOS, BPA offered 316 PTSAs to eligible requests in their transmission queue, representing approximately 14,464 MW of transmission service. Twenty-seven customers signed 153 of those PTSAs for a total of 6,410 MW. Customers did not sign PTSAs for approximately 8,054 MW, allowing BPA to remove these transmission service requests from the queue, freeing up substantial available transmission capacity. This allowed BPA to offer the available transmission capacity for 2,209 MW worth of transmission service without construction of new transmission projects. Further analysis of the signed PTSA's showed that wind projects accounted for 4,716 MW of the total.[74]

BPA's initial cluster study identified eight new areas of reinforcement that were needed for BPA to be able to accommodate all of the PTSAs.[75] The subsequent financial analysis determined that five of the projects could be constructed at BPA's embedded rates (see Figure 15 below):

- McNary-John Day 500-kV line
- Big Eddy-Station Knight 500-kV line and substation
- Little Goose (Central Ferry to Lower Monumental) 500-kV line
- I-5 Corridor Reinforcement (Castle Rock-Troutdale) 500-kV line and substation.
- West of Garrison Remedial Action Scheme[76]

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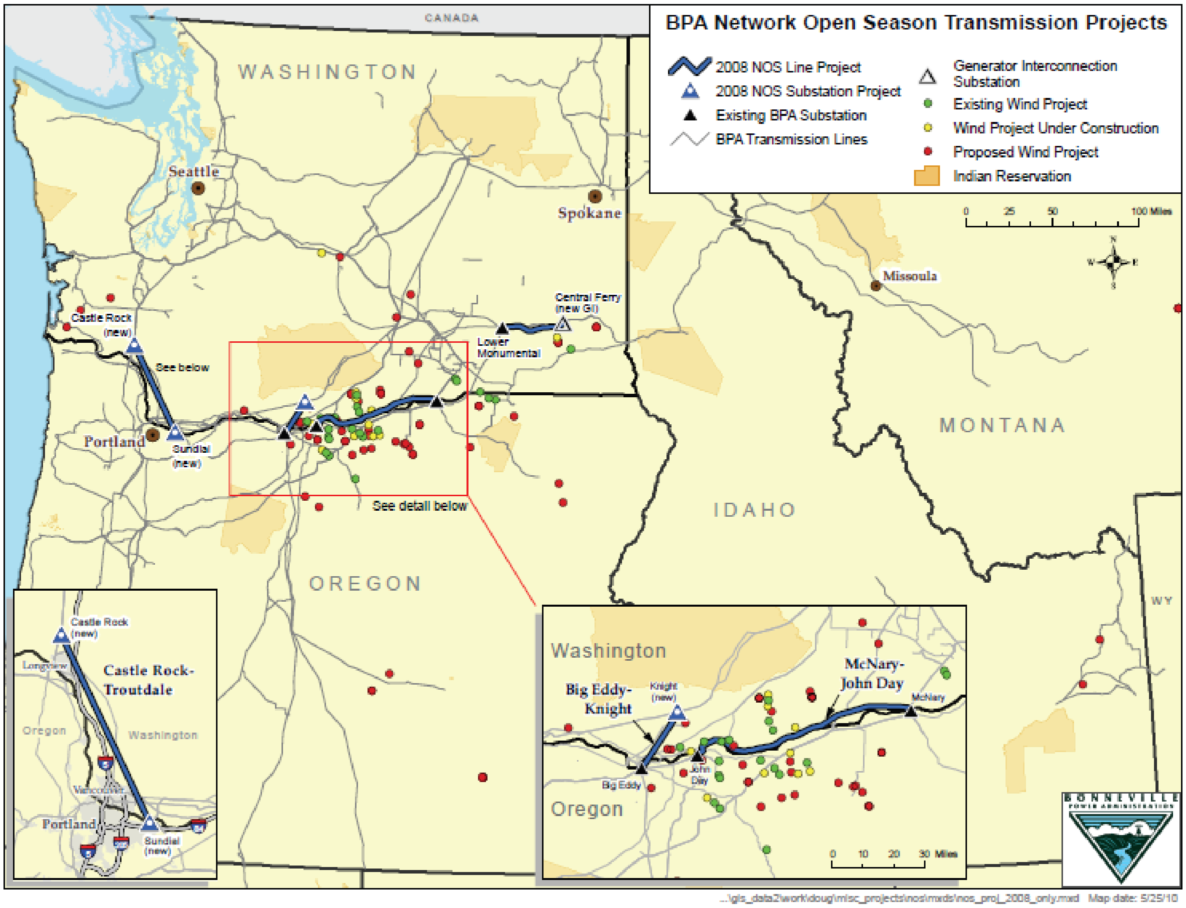
[73] Embedded cost rate refers to the existing long term firm point-to-point transmission rate on file at FERC. If the new transmission service would require upgrades that cost more than BPA's embedded cost rate (i.e. require an incremental rate increase) than BPA would consider the PTSA terminated.

[74] Bonneville Power Administration, *2008 Network Open Season Results*, July 7, 2008, Notice, http://www.transmission.bpa.gov/customer_forums/open_season/docs/2008_NOS_Final_PTSA_Results_07_07_2008.pdf.

[75] Stephen Wright, *2008 NOS Administrators Decision Letter*, Bonneville Power Administration, February 16, 2009, http://www.transmission.bpa.gov/customer_forums/open_season/docs/Decision_Letter_02_16_2009.pdf.

[76] This project was originally proposed but system conditions subsequently allowed BPA to drop it from consideration.

Figure 15. BPA Network Open Season Transmission Projects



Source: Bonneville Power Administration, *2008-2009 NOS Project Summary*, May 27, 2010, p.2, http://transmission.bpa.gov/customer_forums/open_season_2009/2008_nos_Summary_Timeline_Map.pdf.

BPA estimates these projects have a direct cost of approximately $950 million and, assuming BPA makes the decision to build them all, will finance them either through Treasury borrowing or third party financing, supported by the rates of the future transmission users. The McNary-John Day line was an existing project that BPA had previously prepared a NEPA study for. BPA is financing construction of the project with part of the $3.25 billion in increased borrowing authority BPA received from the American Recovery and Reinvestment Act.[77] The project is now under construction and expected to go into service in 2012 and could support 2,275 MW of new wind transmission capacity. Three other projects – Harney, Monroe-Echo Lake, and La Grande – would have required BPA to charge incremental rates, and the relevant PTSAs were terminated with the customers having the option to pursue service under the BPA OATT model.

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[77] Bonneville Power Administration, *Summary of Eligible TSRs for 2009 Network Open Season,* July 22, 2009, http://www.transmission.bpa.gov/customer_forums/open_season_2009/NOS_Eligibility_summary_07-22-09.pdf.

BPA's 2009 network open season was held June 1-30, 2009. BPA reported receiving 4,867 MW worth of requests in the 2009 open season, which ultimately resulted in 34 PTSAs for 1,553 MW of which 923 MW were for wind projects.[78] The cluster study results showed that for 293 MW of those requests BPA could provide transmission service without constructing new facilities and 1,121 MW of requests can be serviced through the projects that moved forward in the 2008 NOS. The remaining 139 MW of requests could not be accommodated at embedded cost and the PTSAs were terminated.[79]

On June 30, 2010, BPA closed the window for the 2010 NOS. BPA received 125 transmission service requests for 7,466 MW from 22 customers that are eligible for PTSAs. Of the total, 78 transmission service requests for 4,456 MW were associated with wind power projects. Customers must execute and return the PTSAs to BPA and meet other requirements, including providing performance assurance, by August 18, 2010.[80]

Wyoming-Colorado Intertie

The Wyoming Infrastructure Authority (WIA), the Western Area Power Administration, and Trans-Elect are developing the 345-kV, 850 MW Wyoming-Colorado Intertie (WCI) transmission project that would run from Wyoming to Denver, Colorado. WIA held an open season in 2008 to pre-subscribe capacity on the line, which resulted in two wind companies committing to 585 MW of available capacity on the WCI project – GreenHunter Wind Energy for 335 MW and Duke Energy Ohio for 250 MW. WIA planned to sell the remaining capacity through bilateral contracts. On April 28, 2009, LS Power, a merchant generation and transmission company, announced it had purchased the rights to the WCI from Trans-Elect. The WCI is projected to be completed sometime in 2014.

Chinook and Zephyr

Zephyr and Chinook are two 500-kV high-voltage direct current transmission projects each with a capacity of 3,000 MW being developed by TransCanada. The Zephyr project would originate in Wyoming while the Chinook project would originate in Montana, with both terminating in the Eldorado Valley south of Las Vegas. In February 2009, FERC granted both projects negotiated rate authority. TransCanada developed a precedent agreement for open seasons that were launched on October 13, 2009. On May 20, 2010, TransCanada announced the results of the Zephyr open season, which resulted in signed precedent agreements for the full 3,000 MW of

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[78] Communications with BPA personnel, August 16, 2010; Bonneville Power Administration, *2009 Network Open Season Update*, Presentation at the Customer Meeting on September 15, 2009.
[79] Stephen Wright, *2009 NOS Decision Letter*, Bonneville Power Administration, May 28, 2010, http://www.transmission.bpa.gov/Customer_Forums/open_season_2009/2009_NOS_decision_letter_final.pdf.
[80] Bonneville Power Administration, *Notice: Summary of Eligible Transmission Service Requests for the 2010 Network Open Season*, July 12, 2010, http://www.transmission.bpa.gov/Customer_Forums/open_season_2010/summary_2010_nos_tsr.pdf.

available capacity on the proposed transmission line with three renewable energy developers in Wyoming – Pathfinder Renewable Wind Energy, Horizon Wind Energy, and BP Wind Energy. TransCanada plans to have the line in-service in by 2015/16.[81] In September 2010, TransCanada suspended the Chinook project, citing lack of market support.[82]

V. Conclusion

This report finds that the United States appears poised for an expansion in transmission investment after years of little or no growth. This report also discusses current transmission cost allocation practices for each RTO and the initiatives that some of the RTOs have either proposed or put in place, such as SPP's Highway-Byway initiative and the California ISO's Location-Constrained Resource Interconnection, as well as a small sample of initiatives by non-RTOs, such as open seasons by BPA, the Wyoming Infrastructure Authority and TransCanada for their proposed Chinook and Zephyr transmission projects. FERC also released a proposed rule in June 2010 that would require transmission owners to participate in regional transmission planning, and to require each regional transmission plan to account for state and national policies, such as state renewable portfolio standards. FERC has also promised to step in and decide transmission cost allocation for a region, based on the record in that particular FERC docket, if that region does not come up with acceptable transmission cost allocation methodologies on its own. It is too early to tell what shape the proposed FERC rule will take if it is implemented, or if it will even be adopted at all, but if it goes forward, continuing regional innovations in transmission cost allocation could be anticipated.

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[81] TransCanada, Zephyr and Chinook Power Transmission Lines, http://www.transcanada.com/zephyr.html (accessed July 30, 2010).
[82] TransCanada Announces withdrawal from the Chinook Transmission Project," September 23, 2010. www.920cleantech.com/details.asp?newsID=12178.

Appendix

The data on the number of projects, and the related cost estimates, of planned and in-service projects in each RTO/ISO used in this paper was taken from a variety of reports and organized for comparison and display. Not all projects listed as planned or in-service by an RTO/ISO included a cost estimate. For any project where an estimate was not provided, zero dollars were added to the total estimate.

PJM

Data on PJM transmission upgrades is included in PJM's RTEP, and the in-service and proposed projects are listed in a Transmission Construction Status queue available on the PJM website[83]. Projects have been classified in this paper depending on the identification in the PJM data:

- Reliability: 'Baseline' projects, which are associated with baseline reliability, absent interconnection projects.
- Generator Interconnection Project: 'Network Upgrades,' which are associated with interconnection projects, including generation, long term firm transmission service, and merchant transmission interconnections.
- Economic: 'Baseline' with a 'Market Efficiency' driver.
- Not Included: 'Supplemental' or 'Transmission Owner Initiated,' which are defined by PJM as projects initiated by the Transmission Owner to fulfill local Transmission Owner criteria, but not deemed necessary for reliability, economic efficiency, or operational performance standards.

Both the in-service projects and the proposed projects for PJM were separated by the 'In-Service date,' which is the date the upgrade is expected to go into service. Where no in-service date was provided, projects were separated by the 'PJM Required Date,' which is the date when the upgrade is needed due to a reliability criteria violation. The In-Service date is typically on or before the PJM required date.

Midwest ISO

Proposed transmission project data in the Midwest ISO was separate from the data for its in-service transmission projects. Proposed transmission project data was taken from Appendix 'A' and 'B>A' of the 2009 MTEP.[84] Appendix A of the 2009 MTEP contains projects which are being or have been approved by Midwest ISO Board of Directors, while Appendix B>A signaled those projects moving during the current planning cycle. Proposed projects from the MTEP were

[83] PJM, Transmission Construction Status, http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx (accessed May 19, 2010).
[84] Midwest ISO, *MTEP09 Midwest ISO Transmission Expansion Plan 2009: Appendices A, B, C*, Project Table 10/16/2009, http://www.midwestmarket.org/publish/Document/254927_1254c287a0c_-7e5b0a48324a?rev=1.

separated by year based on their expected in-service date, which is the date when the entire project is expected to be in service. Projects were classified in this report based on the data's listing of each project's Project Type per Tariff Attachment FF:

- Reliability: 'Baseline Reliability'.
- Generator Interconnection Project: 'Generator Interconnection Project,' or 'Transmission Delivery Service Project'.
- Economic: 'Regionally Beneficial Project'.
- Not Included: 'Other'.

In-service project data for the Midwest ISO for 2002 and 2003 was taken from Appendix A of the 2003 MTEP report.[85] Projects were separated by Planned In-Service Date. In-service project data for the Midwest ISO for the period between 2004 through 2009 was taken from the "March 2010 MTEP In Service Project Listing"[86], which contains in-service projects through the 1st Quarter 2010. Projects were separated by year based on maximum expected in-service date, though the report notes that expected in-service dates are approximate.
Projects classified in this paper as follows:

- Reliability: 'Native Network Load,' 'Improvement (Losses, Maintenance, Availability, Other),' or 'Baseline Reliability'.
- Generator Interconnection Project: 'Generation Interconnect' or 'Generator Interconnection,' 'Transmission Service,' or 'Transmission Delivery Service Project'.
- Economic: 'Regionally Beneficial'.
- Not Included: 'Other,' or those projects without a designation

ISO-New England

Proposed transmission project data and in-service transmission project data for ISO-New England was collected from multiple reports. Proposed transmission upgrade data was retrieved from Table A of the April 2010 ISO-New England Project Listing Update, which is available on the ISO-New England website.[87] Table A includes those projects listed as 'Planned,' meaning the transmission upgrade has ISO approval, pursuant to Section I.3.9 of the ISO New England Transmission, Markets and Services Tariff. The proposed transmission project data collected was separated by projected in-service month/year, and multiple projects listed with one shared cost estimate were counted as a single project. The projects have been organized by the Primary Driver classifications:

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[85] Midwest ISO, *Midwest ISO Transmission Expansion Plan 2003: Appendix A*, June 3, 2003, http://www.midwestmarket.org/publish/Document/3e2d0_106c60936d4_-750e0a48324a?rev=1.
[86] Midwest ISO, *MTEP In-Service Projects 2010-6*, http://www.midwestmarket.org/publish/Folder/5d42c1_1165e2e15f2_-7d370a48324a?rev=2 (accessed June 2010).
[87] ISO New England, *RSP Transmission Project Listing - April 2010 Update*, April 2010, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/2010/project_list_april_2010.xlsx.

- Reliability: 'Reliability Upgrade' drivers.
- Generator Interconnection Project: 'Generation Interconnection' drivers.
- Not Included: 'Elective' drivers.

In-service project data for the ISO New England was gathered from multiple documents. All Reliability project data from 2003 through May 2009 was collected from the "April ISO-New England Project Listing Update: In-Service Transmission Projects 2003-2009" list[88]. Reliability projects after May 2009, as well as GIP, Economic, and Other in-service projects for all included time periods, have been retrieved from the ISO-New England Project Listing Updates.[89] The ISO-New England Project Listing Updates include projects that are part of the Regional System Transmission Plan, and are updated in April, July, and October of each year. These in-service projects are classified in the project listings by their Part Number, which are used to designate the 'need' category of the project. Classifications within this paper were based on the ISO-New England Project Listing Update definitions of Part numbers:

- Reliability: Part 1 (Defined as Reliability Upgrades).
- Generator Interconnection Project: Part 2 (Defined as Generator Interconnection Upgrades).
- Economic: Part 3 (Defined as Market Efficiency Upgrades).
- Other: Parts 4 and 5 (Defined as "projects that may be promoted by any entity electing to support the cost of transmission changes. The entity sponsoring the changes will have their own justification for their actions"[90])
- Not Included: NEMA Economic upgrades (as they were not a part of the ISONE planning process and therefore not relevant to this paper).

Projects were divided by year based on the projected in-service date. Multiple projects in ISO-New England listed with one shared cost estimate were counted as a single project. The reports specify that the cost estimates provided may have some degree of inaccuracy, but for the I.3.9 approved projects the accuracy variance may be no more than 25%, and for TCA-Approved projects, it may be no more than 10%.

[88] ISO New England, *ISO-NEW ENGLAND Project Listing Update: IN-SERVICE PROJECTS (2003 - 2009)*, 2009.
[89] ISO New England, *Transmission Project Listing*, Archives, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/2010/index.html.
[90] Richard V. Kowalski, *Regional System Plan Transmission Projects: June 2010 Update*, 19, PAC Meeting, June 16, 2010, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/2010/june_proj_list_slides.pdf.

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Data for the proposed transmission projects and cost estimates in SPP was taken from the "SPP Board of Directors Approved Appendix A Complete List of Network Upgrades as of January 26, 2010."[91] Projects were separated by year as specified by SPP in the Appendix. In the 2009 STEP, projects are defined as follows:

- Generation Interconnect – Projects associated with a FERC-filed Generation Interconnection Agreement.
- Interregional – Projects developed with neighboring Transmission Providers (Appendix A, only).
- Regional reliability – Projects needed to meet the reliability of the region.
- Regional reliability – non-OATT – Projects to maintain reliability for SPP members not participating under the SPP OATT (Appendix A, only).
- Transmission service – Projects associated with a FERC-filed Service Agreement.
- Zonal Reliability – Projects identified to meet more stringent local Transmission Owner criteria.
- Zonal-sponsored – Projects sponsored by facility owner with now Project Sponsor Agreement.
- Balanced Portfolio – Projects identified by the Balanced Portfolio process.
- Sponsored – Projects with an executed Project Sponsor Agreement or that have previously been identified as an economic project to receive transmission revenue credits under the OATT attachment Z2.[92]

For the purposes of this report, projects have been classified as follows:

- Reliability: 'Regional reliability' or 'Regional reliability non-OATT'.
- Generator Interconnection Project: 'Generation Interconnect' or 'Transmission service.'
- Economic: 'Balanced Portfolio' or 'Sponsored.'
- Not Included: 'Interregional,' 'Zonal Reliability,' or 'Zonal-sponsored.'

SPP In-service project data was collected from a variety of reports. Data for years 2003 and 2004 was taken from Appendix A of the 2005 SPP Transmission Expansion Plan.[93] Corresponding in-service project data for 2005 was unavailable. SPP in-service project data for 2006-2010 was

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[91] Southwest Power Pool, *SPP Board of Directors Approved Appendix A Complete List of Network Upgrades as of January 26, 2010*, 2010, http://www.spp.org/publications/1_26_2009%20BOD%20Approved_Appendix%20A%20-%20Complete%20List%20of%20Network%20Upgrades2.pdf.

[92] Southwest Power Pool, *2009 SPP Transmission Expansion Plan: Appendix A and B Instructions*, 1, http://www.spp.org/publications/2009%20SPP%20Transmission%20Expansion%20Plan%20(Redacted%20Version).pdf.

[93] Southwest Power Pool, *RTO Expansion Plan 2005-2010*, August 2005, http://www.spp.org/publications/Planned_ExpPlan_NewProjectForms_08_01_05.xls.

collected from 2009 Quarters 1, 2, 3, 4, and 2010 Quarters 1 and 2 Project Tracking Lists.[94] If a project was listed as in-service on more than one Project Tracking list, the most recent version was selected. The projects are separated by the Project Owner Indicated In-Service Date. To estimate the costs each year, the final cost was used for projects where it was provided, and the current cost estimate used in its absence. Upgrades with a single shared cost estimate were counted as a single project. In a case where multiple upgrades contain a shared cost estimate but list different in-service years, the project has been included under the latest year listed.
For this report, projects have been classified as follows:

- Reliability: 'Native Network Load,' 'Improvement (Losses, Maintenance, Availability, Other),' 'Transmission Owner Planned,' 'Reliability project that SPP Recommends to the BOD for Authorization to Construct,' or 'Regional Reliability.'
- Generator Interconnection Project: 'Generation Interconnect,' 'Transmission Service,' or 'Interconnection Agreement.'
- Economic: 'Economic' or 'Sponsored.'
- Other: Projects without classification.
- Not Included: 'Reliability project not within budgeting cycle,' 'Out of Cycle Reliability project,' 'Reliability project not under SPP tariff,' or 'Project Tracking.'

[94] Southwest Power Pool, *Quarterly Project Tracking Reports*, http://www.spp.org/section.asp?group=1867&pageID=27.

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Several Regional Transmission Organizations (RTOs) have experimented with innovative transmission cost allocation strategies, and that is the primary focus of this report.

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