The Brattle Group

Summary of Transmission Project Cost Control Mechanisms in Selected U.S. Power Markets

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Acknowledgements and Disclaimer
The authors acknowledge the valuable input from a number of market participants in various U.S. power markets. Opinions expressed in this report, as well as any errors or omissions, are the authors' alone. The transmission cost control mechanisms summarized in this report represent our interpretations of existing requirements. The authors are economic consultants, not lawyers, and nothing herein is intended to provide, nor should the AESO infer that the report represents, legal advice or a legal opinion in any form or fashion.

I. Background

We were asked by the Alberta Electric System Operator ("AESO") to document and summarize U.S. efforts aimed at controlling costs of transmission projects in an effort to mitigate the risk of significant increases in the cost of planned transmission projects after they have been evaluated and approved. More specifically, we were asked to address the following questions:

1) How are transmission costs managed? Who is responsible?

2) Who, or under what framework, reviews/approves transmission capital expenditure prudency?

3) What roles do independent system operators ("ISOs") or regional transmission operators ("RTOs") play with respect to transmission cost control?

4) What interactions do ISO/RTOs have with stakeholders regarding transmission costs?

5) What incentives do transmission owners ("TOs") and ISO/RTOs have with respect to transmission cost containment?

The last several years have seen significant increases in transmission investments. For example, as we have documented elsewhere, recent levels of annual U.S. transmission investments are four times the annual investment levels during the 1990s, when investment levels were at historically low levels as compared to the major construction boom during the 1960s through early 1980s.[67] The current increase in transmission investments, which is anticipated to continue for the foreseeable future,[68] also has been associated with significant increases in the initial planning-related cost estimates for transmission projects.

For example, in 2008 the Public Utilities Commission of Texas ("PUCT") approved a transmission plan to integrate additional wind generation in selected competitive renewable energy zones ("CREZ"). In 2008, this CREZ transmission plan ("CTP") had an estimated total cost of $4.9 billion.[69] As of today, however, the CTP projects are estimated to cost $6.8 billion—mostly because the initial cost estimates did not account for a number of factors, such as financing costs during constructions, costs related to reactive compensation, upgrades to lower-voltage transmission facilities, or the fact that the length of transmission lines increased due to re-routing requirements.[70]

In addition to cost increases resulting from more comprehensive and precise cost estimates, a number of transmission projects planned prior to 2008 have seen significant cost increases due to unanticipated increases in the costs of labor, equipment, and raw materials (such as steel, copper, and aluminum). Between 2004 and 2007, the costs of transmission projects increased by approximately 30% while economy-wide inflation increased the average costs of consumer goods and services by only 8%.[71] For example, in an August 2004 filing before ISO New England Inc. ("ISO-NE"), NSTAR indicated that one of its projects would cost $234 million. By March 2007, NSTAR informed ISO-NE that estimated project costs had increased by $58 million, or almost 25 percent, for a revised total project cost of $292 million. As NSTAR explained, this cost increase was driven by increases in both construction and material costs, with construction bids coming in 24 percent higher than initially estimated.[72] These unexpected cost increases were related to strong global demand for materials, which increased copper costs by 160

[67] For example, see Pfeifenberger and Hou, "Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada," The Brattle Group, prepared for WIRES, May 2011. Posted at: http://my.brattle.com/_documents/UploadLibrary/Upload947.pdf

[68] *Id.*

[69] PUCT, Docket No. 35665, Order on Rehearing, May 15, 2009.

[70] Competitive Renewable Energy Zone Program Oversight, *CREZ Progress Report No. 4 (July Update)*, prepared by RS&H for Public Utility Commission of Texas, July 2011.

[71] Chupka and Basheda, "Rising Utility Construction Costs: Sources and Impacts," *The Brattle Group*, Prepared for The Edison Foundation, September 2007, p. 2.

[72] *Id.,* p. 11.

percent, core steel by 70 percent, flow-fill concrete by 45 percent, and dielectric fluid (used for cable cooling) by 66 percent.[73]

Since system operators and regulators often evaluate and approve projects based on initial cost estimates, several U.S. regions have implemented or are evaluating the implementation of additional mechanisms to reduce the risk of unexpected cost increases through improved cost estimation protocols and monitoring of transmission costs. The remainder of this report summarizes the regulatory framework for controlling transmission project costs in the U.S. and describes a number of mechanisms that were implemented or are being considered in regions with significant recent transmission investment activity: ISO-NE, Texas, the Southwest Power Pool ("SPP"), the Midwest ISO, and California.

II. Overview of cost control through planning and prudence-reviews of U.S. Transmission Investments

A. Planning of Transmission Projects in the U.S.

In U.S. electricity markets, the TOs and ISOs/RTOs are the primary parties responsible for managing transmission costs from a planning perspective. In other words, ISOs/RTOs and transmission owners are generally responsible for identifying cost effective transmission projects (or non-transmission alternatives) via a transmission planning process that addresses transmission needs, such as identified reliability concerns. These planning processes have to be compliant with transmission planning requirements set out in Order 890 of the U.S. Federal Energy Regulatory Commission ("FERC"). FERC regulates all U.S. wholesale transmission functions outside the Electric Reliability Council of Texas ("ERCOT").

Transmission plans approved by ISOs/RTOs (in regions where they exist), however, still require that the TOs responsible for implementing a particular ISO/RTO-approved transmission project obtain any necessary permits from individual state commissions or state siting authorities and, where applicable, federal land management authorities. These state-level permitting processes often include a determination of needs, which may also require the evaluation of the cost effectiveness of a planned transmission project from the perspective of each individual state.

B. Cost Control During the Development and Construction of Approved Projects

TOs are the primary parties responsible for managing costs during the project development and construction efforts, including the many factors that can influence costs, such as unforeseen route changes to accommodate landowners or wildlife habitats, changes in material and labor costs throughout the planning and construction effort, and other changes from original plans.

Prudence reviews are the primary U.S. regulatory mechanisms to provide incentives for cost accountability during these development and construction phases of a project. Before transmission costs can be recovered in transmission rates, their inclusion is subject to regulatory approval and the possibility of prudence-related challenges. The process for prudence reviews of transmission projects differs depending on the extent to which individual states have unbundled the transmission function in retail rates.

FERC has jurisdiction over all wholesale transmission service, which includes any unbundled transmission service to retail customers. Transmission service is an unbundled component of retail rates in all states that introduced retail competition (*e.g.*, California, Illinois, and most states on the east and west coasts) as well as a few traditionally-regulated states (such as Arizona and Kansas) which have unbundled transmission service to retail customers without restructuring and the introduction of retail competition.

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[73] *Id.*, p.11.

Parties that question the prudency of transmission costs before FERC are able to file a complaint under Section 206 of the Federal Power Act. This requires a demonstration that an expenditure was unnecessary or imprudent, such that the recovery of these costs would lead to FERC-jurisdictional transmission rates that are unjust and unreasonable.

The Section 206 complaint option is also available to challenge the wholesale transmission rates of vertically-integrated utilities even if they have not unbundled transmission services, both within and outside of ISO/RTO regions.[74] However, utilities with bundled retail rates are also subject to prudency reviews at the state level for their overall revenue requirements (including generation and distribution) in each of their retail rate cases before the state regulatory commissions. Such state-level prudence reviews of transmission costs do not apply to integrated utilities with unbundled transmission rates for their provision of their retail service and wholesale-only transmission companies that are not subject to state retail rate regulation.

While ISOs/RTOs, where they exist, have taken on a key role in the determination of transmission needs and the development of cost-effective transmission plans to address these needs, they have only limited means to control the costs of ISO/RTO-approved transmission projects as they progress through the development and construction phases. Up until recently, most ISOs/RTOs relied solely on the basic reporting process outlined in Order 890, which requires TOs to submit initial cost estimates with updates to the estimates throughout the various phases of the transmission planning process.[75] This reporting requirement provides some incentives for cost accountability and facilitates cost control by providing stakeholders the opportunity to review and ask questions about initial cost estimates and the periodically-reported updates.

As discussed in the remainder of this report, recent cost increases in major transmission projects have prompted changes to some of the ISOs/RTOs' cost estimation and reporting requirements. As summarized below, several ISOs/RTOs have established or are evaluating additional cost control measures:

- **ISO-NE**, which implemented additional cost estimation processes and reporting requirements;
- **Texas**, which established an oversight process for transmission planned and built under its CREZ requirements;
- **SPP**, which is in the process of developing cost estimation and reporting requirements;
- The **Midwest ISO**, which is developing similar requirements; and
- **California**, which allows for cost containment measures as part of its newly-approved competitive bidding process for economic and public policy projects.

III. Summary of Selected U.S. Transmission Project Cost Control Mechanisms

A. ISO-New England

ISO-NE has experienced a significant increase in transmission investments, having approved and placed into service $4.6 billion of transmission over the last few years with a projected additional transmission investment of $5.3 billion over the next 10 years.[76] Many of the approved projects received FERC incentive returns and a number of them exceeded initial cost estimates, as illustrated by the NSTAR

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[74] Note that ISOs/RTOs operate regions that contain both restructured and traditionally-regulated retail electricity markets. For example, most (but not all) of the states in the region covered by ISO-NE, NYISO and PJM have restructured retail markets, while most of the states in the region covered by the Midwest ISO and SPP still have a traditionally-regulated industry with vertically-integrated, cost-of-service regulated utilities. ERCOT is operating in the retail restructured portion of Texas, but is not subject to FERC regulation.

[75] FERC Order 890 (paragraph 472) specifically "requires that transmission providers make available information regarding the status of upgrades identified in their transmission plans in addition to the underlying plans and related studies. It is important that the Commission, stakeholders, neighboring transmission providers, and affected state authorities have ready access to this information in order to facilitate coordination and oversight." The order (issued February 16, 2007) is posted at: http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

[76] ISO New England, *2011 Regional System Plan: Public Meeting Draft*, September 1, 2011, p. 90.

example summarized above. Since New England states are restructured and transmission costs are recovered entirely through FERC-approved rates, New England state regulatory commissions voiced with FERC their concerns over the magnitude of transmission investments, the FERC incentive ROEs, the cost overruns, and the fact that the incentive ROEs are earned even on the cost overruns. For example, in 2008 the New England Conference of Public Utilities Commissioners, Inc. ("NECPUC") filed a Section 206 complaint against the New England Transmission Owners arguing that the FERC-approved incentive ROEs were unjust and unreasonable.[77] As of May 2011, FERC had denied NECPUC's compliant and request for rehearing.[78]

Although ISO-NE does not have a role in determining the accuracy of cost estimates or the prudence of realized project costs, it has implemented a process for cost reviews (Planning Procedure No. 4 or PP-4)[79] and project cost estimating guidelines (Attachment D to PP-4).[80] This process is applied mainly to necessary regulated transmission projects over $5 million that will receive regional cost recovery (*i.e.,* postage stamp treatment).[81] This cost review process does not apply to generator interconnection upgrades, elective transmission upgrades, local area upgrades, and merchant transmission facilities.[82] PP-4 provides guidance on which projects are subject to cost review, what information the Project Sponsor must provide to ISO-NE, the process for reviewing a Project Sponsor's application, and periodic reporting of costs associated with a project.[83] Each Project Sponsor must also complete and submit an annual Transmission Cost Allocation ("TCA") application.[84] If the TCA application is approved, the ISO will allow regional cost allocation and include the sponsored project in the revenue requirement for regional cost recovery unless disallowed by FERC in response to a Section 206 complaint.

Three groups within the ISO are charged with providing guidance and reviewing TCA applications. At the initial planning stage, the ISO-NE Planning Advisory Committee ("PAC") will "review proposed solutions and may offer advisory input to the ISO as to the most cost effective and reliable solutions for the region that meet a need identified in a Needs Assessment through the Regional System Planning Process."[85] Project Sponsors can use this feedback in its TCA application, which is formally submitted to the Reliability Committee ("RC") for review and may include detailed cost breakdowns for labor, materials, engineering, and permitting, costs of alternatives to the proposed project, and various maps and diagrams.[86] The RC then makes a recommendation to the ISO and the ISO will provide a final written findings and determination. Projects with significant costs and/or complexity may be subject to information requests and additional stakeholder review.[87]

Cost estimating guidelines provided in Attachment D to PP-4 are meant to ensure that different TOs use the same approach and levels of accuracy for estimating costs at various stages of the planning and project development process. For example, as Table 1 shows, projects at a conceptual planning stage such as during "project initiation" can have a wide cost variance of -50% to +200% whereas cost estimates for projects in the construction phase are required to have an uncertainty range of only +/-10%. TOs use Attachment D guidelines to report updated cost estimates to the ISO and its PAC at least once a year or whenever the cost estimates change by more than 10% or there is a material change in the design of the facility.[88] The reports also get posted to the ISO website,[89] which allows other stakeholders to protest and, if needed, get ready for a prudence challenge at FERC. This process is said to have provided significant additional incentives for TOs to estimate costs accurately and control project costs to

77 *New England Conference of Pub. Utils. Comm'rs, Inc. v. Bangor Hydro-Elec. Co.,* 124 FERC ¶ 61,291 (2008) (September 2008 Order).

78 *New England Conference of Pub. Utils. Comm'rs, Inc. v. Bangor Hydro-Elec. Co.,* 135 FERC ¶ 61,140 (2011) (May 2011 Order).

79 ISO New England Planning Procedure No. 4, Procedure for Pool-Supported PTF Cost Review, September 17, 2010. Posted at: http://www.iso-ne.com/rules_proceds/isone_plan/pp4_0_r5.pdf.

80 Posted at: http://www.iso-ne.com/rules_proceds/isone_plan/pp4_0_attachment_d.pdf

81 ISO New England, "Planning Procedure No. 4: Procedure For Pool-Supported PTF Cost Review" and "Attachment D" of Planning Procedure No. 4.

82 *Id.*, p. 3.

83 *Id.*, p. 1.

84 *Id.*

85 *Id.*, p. 3.

86 *Id.*, pp. 5-7.

87 *Id.*

88 ISO New England, Sections 1.4 and 1.10, "Planning Procedure No. 4: Procedure For Pool-Supported PTF Cost Review."

89 The ISO reviews the Cost Estimation Update and posts the updates on the ISO website at the following address: http://www.iso-ne.com/trans/pp_tca/req/proj_cst_est/index.html.

avoid overruns which, if found unreasonable, can jeopardize regional cost allocation and trigger prudence challenges.

Table 1
Cost Estimate Types and Uncertainty Bands in ISO-NE Planning Procedures

Project Stage	Level of Project Definition	Estimate Type	Regional Review	RSP Listing Target Accuracy
Project Initiation	0% to 15%	Order of Magnitude	Need Approval (RSP Listing)	-50% to +200%
Proposed Project	15% to 40%	Conceptual Estimate	RC Review / Retain Proposed Solution	-25% to +50%
Planning Project	40% to 70%	Planning Estimate	PPA Approval	-25% to +25%
Final Project Design	70% to 90%	Engineering Estimate	RC Review / TCA Approval	-10% to +10%
Under Construction	80% to 100%	Construction Estimate		-10% to +10%

Sources and Notes:
Selected data from ISO New England, *Table 1: Cost Estimate types per project phase (From AACE definition & customized for Transmission Project)*, Attachment D of "Planning Procedure No. 4: Procedure For Pool-Supported PTF Cost Review."

B. Texas CREZ

ERCOT is the independent system operator for most of Texas. ERCOT differs from other ISO regions in the U.S. because: (1) it is a single-state ISO (Texas); and (2) it is not regulated by the FERC. ERCOT operations (including market monitoring and costs) are overseen by the Public Utility Commission of Texas, which also regulates the rates and terms of all in-state transmission. In 2005, Texas Senate Bill 20 established a renewable energy requirement for the state and directed the PUCT to identify Competitive Renewable Energy Zones ("CREZ"). Based on analysis performed by ERCOT, five major zones were identified and a $4.9 billion transmission overlay was designed to interconnect a total of 18,500 MW of installed wind capacity. Companies designated to build portions of the CREZ transmission overlay were selected by the PUCT and included both incumbents and new entrants. As part of its implementation of CREZ, the PUCT also designated an Executive Director to establish a scope of work, monitor the progress of assigned transmission projects, and report to the PUCT. With regard to cost containment and deviations, the PUCT requires:

1. Within six months of granting a Certificate of Convenience and Necessity ("CCN"), the responsible TO needs to report estimated total cost information for its designated facility based on: CCN acquisition, right-of-way and land acquisition, engineering and design, procurement of materials and equipment, and construction of facilities.[90] In addition, the PUCT required TOs to report their financing methods, costs, and schedules.[91]
2. Should costs deviate more than 15% from the most current estimate, TOs are required to report any such deviations within 10 days of becoming aware of it.
3. One year after CCN approval, each designated TO will file an updated total cost estimate which will be updated annually until the facility is placed in-service.[92]

The PUCT also provides TOs, in collaboration with ERCOT, with some flexibility in proposing modifications to planned projects to the extent that it reduces costs, increases the amount of generation it interconnects, reduces time to construct, achieves technical efficiency, or improves cost-effectiveness.[93]

As of July 2011, the original $4.9 billion (2008$) estimate for the total CREZ transmission overlay had increased to $6.8 billion.[94] As explained in the quarterly reports of the CREZ Program Oversight, this cost increase is due to a number of reasons including:

1. Transmission costs were based on illustrative costs before detailed engineering and design analyses;
2. Right-of-way costs varied from illustrative costs;
3. Locations were only approximate relied on "straight-line" distances;
4. Original estimate is based on 2008$;
5. Contingency markups do not seem to have been used;
6. Original estimates did not include varying financing costs; and
7. Not all elements of the buildout were included in the original estimate such as the need for more reactive power compensation.[95]

While costs have increased, we are not yet aware of an incident where the PUCT has disallowed some of these cost overruns or ordered modifications. However, we understand from conversations with TOs that the cost estimation and reporting requirements significantly increased their efforts to improve the

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90 Public Utility Commission Substantive Rule 25.216(f)(2).

91 Public Utility Commission of Texas, Order on Rehearing, Docket No. 35665, May 15, 2009, p. 21. (Note that TSP selection of Docket No. 35665 was remanded to Docket No. 37902; however, cost reporting requirements remained unchanged.)

92 Public Utility Commission Substantive Rule 25.216(f)(5).

93 Public Utility Commission of Texas, Order on Rehearing, Docket No. 35665, May 15, 2009, p. 24.

94 Competitive Renewable Energy Zone Program Oversight, *CREZ Progress Report No. 4 (July Update)*, prepared by RS&H for Public Utility Commission of Texas, July 2011, p. 6.

95 Competitive Renewable Energy Zone Program Oversight, *CREZ Progress Report No. 4 (July Update)*, prepared by RS&H for Public Utility Commission of Texas, July 2011, pp. 4-5.

accuracy of cost estimates and control project costs to remain within an acceptable range of these estimates.

For non-CREZ transmission builds, the PUCT allows TOs to update transmission rates twice a year to reflect changes in invested capital. These interim rate adjustments are still subject to PUCT review and final approval when the TO files a rate review or rate case.

C. Southwest Power Pool

On April 27, 2010, the SPP Board approved $1.1 billion in new 345 kV upgrades called the Priority Projects.[96] By October 2010, these engineering and construction cost estimates had increased by $271 million, or 24%, for a variety of reasons including line re-routing due to environmental challenges, additional reactive support, and refinement of the project scope within shared projects.[97] These costs would be recovered through SPP's new cost allocation methodology ("Highway/Byway"), which fully or partially spreads costs across the entire RTO footprint for all Board-approved projects above 100 kV.

To improve project cost control and increase cost accountability, the SPP Regional State Committee ("RSC"), comprised of state regulatory commission representatives from each state in the SPP region, made five motions to address the issue of project cost management last fall.[98] Specifically the RSC recommended that:

1. SPP review what is the best manner to address significant cost increases and/or overruns of transmission projects that are regionally funded.
2. SPP review the "Novation Process"[99] and report to the RSC by April 2011.
3. SPP consider establishing design & construction standards for transmission projects above 100 kV that are fully or partially regionally funded.
4. SPP evaluate how cost estimates are established for transmission projects before cost-benefit analyses are performed.
5. The CAWG[100] study various methods on how costs that exceed some standard can be addressed with different cost allocation mechanisms and recommend strategies to the RSC.

Thus far SPP working groups have developed, and the RSC has approved, a series of improvements grouped into the following four topics:

1. <u>Design Best Practices and Performance Criteria</u> – Develop best practices and performance criteria so deviations and variations can be tracked and reported.
2. <u>Tracking/Estimates</u> – Implement a Standardized Cost Estimating Reporting Template ("SCERT") with increasing cost estimate requirements and narrowing variance bands as the project moves from conceptual design to construction.
3. <u>Estimates Outside a Bandwidth</u> – Establish allowed cost variance bands and processes for addressing deviations outside of the band.
4. <u>Assignments and Novations</u> – The RSC would review assignments and novations for cost containment measures and potentially use a competitive bidding process if the assignment or novation is not acceptable.[101]

With respect to the last recommendation, note that SPP assigns Board-approved upgrades to incumbent TOs within the RTO via a notice to construct ("NTC"). The incumbent TO has a 90 day right of first refusal where it can "assign" the legal right to build an upgrade to a third party while retaining a legal

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[96] SPP, "SPP Approves Construction of New Electric Transmission Infrastructure To Bring $3.7 Billion in Regional Benefits," April 27, 2010.
[97] SPP, *Priority Project Update*, presented by Bruce Rew to the SPP Regional State Committee, October 25, 2010.
[98] SPP Regional State Committee, "ITP20 and Priority Projects Update," meeting notes for October 25, 2010 meeting, p. 5.
[99] SPP has a process where an incumbent Transmission Owner has the option to assign its legal obligation to construct SPP Board-approved projects in its service territory to a third party of its choosing.
[100] Cost Allocation Working Group, a group under the Regional State Committee.
[101] SPP RSC Cost Allocation Working Group (CAWG), "CAWG Report: Novations of SPP Approved Transmission Projects Reconsidered," July 25, 2011.

obligation that the project is built.[102] On the other hand, the incumbent TO can use the novation process to completely release itself from any legal obligation to build and assign it to a third party of its choosing.[103] A cost containment concern arises from the novation process should an incumbent TO assign a project to a TransCo affiliate that receives a higher return on equity (*i.e.*, FERC-approved incentive rates) "resulting in higher costs to ratepayers throughout the SPP footprint, with no apparent increase in benefits."[104]

The newly formed SPP Project Cost Task Force ("PCTF") has developed a revised process to evaluate project costs from the conceptual stage through construction. Table 2 summarizes the proposal in the PCTF's most recent whitepaper,[105] showing the cost estimates and variance bands that will be used in project evaluations. For example, at the conceptual stage of a project a variance band of -50% to + 100% of estimated project costs is acceptable for including the project in the Integrated Transmission Plan ("ITP" for both the 20-year and 10-year analyses) but only a -20% to +20% range variance band is acceptable as the project moves into the construction phase. Of the five RSC motions, only the last one, directed at the CAWG, remains outstanding as of the publication date of this report.

Table 2
Cost Estimate Stage Definition as Proposed by the SPP Project Cost Task Force

Estimate Name*	Project Definition	End Usage	Precision Bandwidth
Conceptual	0% to 10%	Concept screening for ITP20/ITP10	-50% to + 100%
Study Phase	10% to 20%	Feasibility study and plan development for ITP10/ITPNT	-30% to +30%
Notice to Construct is issued	20% to 40%	Final baseline (Conditional Notice to Construct or Notice to Construct)**	-20% to +20%
Project design and construction	40% to 100%	Design after Notice to Construct issued and build the project	-20% to +20%***

Sources and Notes:
Selected information from "Table 1: Cost Estimate Stage Definition" of SPP Project Cost Task Force, *Project Cost Task Force Whitepaper*, July 19, 2011, p. 8.
* The conceptual estimate will be prepared by SPP. All subsequent estimates will be prepared by the designated TO(s).
**SPP board approval required to reset the baseline.
***Actual cost is expected to be within +/-20% of final baseline estimate.

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102 SPP Strategic Planning Committee Task Force, "Response to RSC Motions," June 16, 2011, p. 5. Note that the 90 day right of first refusal will likely be revised in accordance to FERC Order 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*.
103 SPP Strategic Planning Committee Task Force, "Response to RSC Motions," June 16, 2011, p. 5.
104 SPP RSC Cost Allocation Working Group (CAWG), "CAWG Report: Novations of SPP Approved Transmission Projects Reconsidered," July 25, 2011.
105 SPP Project Cost Task Force, *Project Cost Task Force Whitepaper*, July 19, 2011.

D. Midwest ISO

The Midwest ISO does not currently monitor and validate TO-reported costs but relies on quarterly reporting of ISO-approved project costs by transmission owners to provide transparency as required under FERC Order 890.

Under its planning function, the Midwest ISO is reviewing the cost effectiveness of proposed transmission projects. For example, the Midwest ISO Board is currently reviewing a group of high-voltage Multi Value Projects ("MVP") estimated to cost over $4 billion.[106] These MVPs are part of a larger footprint-wide transmission expansion to address various needs such as reliability and renewable integration and costs would be eligible for regional cost allocation (*i.e.,* postage stamp cost allocation).

E. California ISO

The California ISO ("CAISO") is a single-state ISO under FERC jurisdiction. California also unbundled the transmission component of its retail rates, which makes transmission rates fully FERC jurisdictional.

In its recently FERC-approved Revised Transmission Planning Process ("RTPP"), CAISO implemented the option of a competitive open bidding process for transmission projects that would meet public policy and economic needs (*i.e.,* not reliability driven projects).[107] CAISO would first identify such needs through its planning process so that all interested developers can then propose projects to meet these needs. Should CAISO receive competing proposals to build the same or similar transmission facility, it will rely on 10 factors to evaluate the project, one of which is a voluntary demonstration of cost containment measures or willingness to enter into a binding cost cap that would preclude the project sponsor from recovering costs above the cap from the CAISO's tariff-based cost recovery mechanism.[108] While cost containment measures or a binding cost cap may reflect favorably on a proposed project, the CAISO declines to use the estimated cost of a project as a deciding factor to select amongst competing proposals "because such a criterion would provide an incentive for Project Sponsors to deliberately underestimate their costs, and the ISO, unlike public utility commissions … has no authority to enforce compliance with such estimates."[109] In its conditional approval of the RTPP, FERC agreed with CAISO's approach.[110] At this point the RTPP process is new and untested and may potentially undergo some revision in response to FERC's recent Order 1000 on U.S. transmission planning and cost allocation.

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106 Midwest ISO, "Midwest ISO Board Approves MTEP10 Endorsing 231 New Projects," December 2, 2010.
107 California ISO, *Revised Transmission Planning Process Proposal*, Docket No. ER10-1401, June 7, 2010.
108 California ISO, *Order Conditionally Accepting Tariff Revisions and Addressing Petition for Declaratory Order*, Docket No. ER10-1401, December 16, 2010, p. 65.
109 California ISO, *Revised Transmission Planning Process Proposal*, Docket No. ER10-1401, June 7, 2010, p. 9.
110 California ISO, *Order Conditionally Accepting Tariff Revisions and Addressing Petition for Declaratory Order*, Docket No. ER10-1401, December 16, 2010, p. 71.