

Client Alert

Latham & Watkins Finance Department

Recent FERC Actions Indicate Significant Changes in Regional Transmission Planning and Cost Allocation

"Largely driven by the need to facilitate the development of critically-needed transmission infrastructure to meet public policy goals... these recent FERC actions indicate significant movement by the Commission in establishing new federal policies for regional transmission planning and cost allocation."

On June 17, 2010, the Federal Energy Regulatory Commission (FERC or the Commission) issued a notice of proposed rulemaking on regional electric transmission planning and cost allocation principles, which was published in the Federal Register on June 30, 2010, and for which public comments must be submitted before August 30, 2010.¹ Generally echoing some of the key policies proposed in the NOPR, on June 17, FERC accepted for filing proposed revisions to the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) adopting a new "Highway/Byway" cost allocation methodology (Highway/Byway Methodology) under which the costs for certain upgrades to SPP's transmission system will be allocated according to the voltage of the new facilities.²

In addition, FERC issued an order in *Central Transmission, LLC v. PJM Interconnection, L.L.C.* finding that a non-incumbent independent transmission developer is eligible to be designated by PJM, on a non-discriminatory basis, to construct, own and receive cost-based rate recovery for an economic transmission project included in PJM's regional transmission plan.³ Largely driven by the need to facilitate the development of critically-

needed transmission infrastructure to meet public policy goals, such as state Renewable Portfolio Standards (RPS), these recent FERC actions indicate significant movement by the Commission in establishing new federal policies for regional transmission planning and cost allocation.

Transmission Planning NOPR

The Transmission Planning NOPR requires public utility transmission providers, including Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) to establish transmission planning processes and cost allocation methods for new intraregional and interregional transmission facilities. The NOPR requires each utility to make compliance filings either (a) demonstrating that existing methods satisfy the NOPR's proposed requirements or (b) establishing new procedures to comply with the NOPR's requirements.⁴ Compliance filings for intraregional facilities are due within six months of the adoption of the final rule issued as a result of the NOPR, and compliance filings for interregional facilities are due within one year of the adoption of the final rule.⁵ If the transmission providers or respective regions cannot reach

agreement with customers and other stakeholders or each other within the requisite time, FERC will establish the planning procedures and cost allocation methods for them based on the record of the compliance proceeding.⁶ Nonpublic utility transmission providers must meet these requirements to maintain their safe harbor status and otherwise to satisfy open access reciprocity requirements.⁷

The NOPR would establish five categories of requirements:

- 1. Regional Planning.** The NOPR observes that Order No. 890⁸ required each public utility transmission provider to adopt an open and transparent process to develop a transmission plan for its own control area, but Order No. 890 did not extend this requirement to mandatory regional planning.⁹ The NOPR would establish a regional planning requirement for all public utility transmission providers. The NOPR states that a regional process is needed so that transmission providers can better assess local projects. Regional planning may produce more cost-effective solutions and could better facilitate integration of new resources, particularly renewable resources. The NOPR would require each regional process to comply with seven principles: (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution and (7) economic planning studies. Regional processes must consider transmission and non-transmission solutions and develop a regional plan to meet needs of transmission customers and other stakeholders in the region. The processes must ensure that all stakeholders may participate and will have access to data, models and other information.¹⁰
- 2. Public Policy Driven Projects.** In addition to reliability and economic considerations, the NOPR would
- 3. Rights of First Refusal.** The NOPR would require each public utility transmission provider to amend its OATT to eliminate rights of first refusal (ROFRs) to construct transmission projects and to provide project sponsors with the right to construct and own their projects, consistent with state and local law. OATTs must establish non-discriminatory qualification criteria for all project sponsors. OATT amendments should establish forms for submitting all needed project information, as well as cut-off dates for the submission of projects for a planning cycle (to prevent competitors from later tweaking a project to take it over). OATTs also must describe non-discriminatory criteria for evaluating projects. If a project is not approved in an initial planning cycle, the sponsor would have a priority to develop the facility if subsequently approved within a reasonable period of time (*e.g.*, five years). All project sponsors

require planning process to take into account transmission to meet public policy requirements, such as state RPS.¹¹ The NOPR preliminarily finds that prudence and nondiscrimination dictate consideration of these objectives. Each public utility transmission provider must amend its OATT to specify the procedures and mechanisms in its local and regional planning processes that will be used for evaluating public policy driven projects. The NOPR states that such proactive planning may improve the efficiency of transmission planning by reducing the need for individual generator requests.¹² The Commission is also seeking comment on whether it would be better to have "flexible criteria" for public policy driven projects, rather than a "bright line" test that may "inappropriately result in the inclusion and exclusion of a single project over successive planning cycles, which could disrupt long-term planning."¹³

must have the same opportunity to recover costs of projects included in a regional plan, and costs of projects not included in a regional plan may not be recovered through a regional cost allocation mechanism. The NOPR states that the elimination of federal ROFRs is not intended to preempt any state or local laws or regulation that may affect who can build transmission projects. While the Commission preliminarily finds that incumbent and non-incumbent transmission facility developers should receive the same treatment in the transmission planning process, and that they should have the same benefits and obligations, the NOPR asks for comments on, among other things, the relationship of federal ROFRs to federal obligations to build.¹⁴

4. Interregional Planning. The NOPR would require each public utility transmission provider, through its regional transmission planning process, to coordinate with neighboring planning regions. This coordination must be reflected in an interregional transmission planning agreement between pairs of neighboring regions to be filed with FERC. Such bilateral agreements must include a detailed description of the process of coordination between public utility transmission providers with respect to facilities that are proposed to be located in both regions, as well as interregional facilities that have not been proposed but could improve efficiency. Each agreement must also include: (1) a commitment to share regional plans and identify possible interregional facilities that could address transmission needs more efficiently than separate intra-regional facilities; (2) data and information exchanges at least annually; (3) a formal procedure to jointly evaluate facilities proposed to be located in both regions; and (4) a commitment to maintain a website or email list for the communication if

information related to the coordinated planning process.¹⁵

The NOPR would require sponsors of interregional projects to first propose the project in the planning processes of both regions, which would then trigger a coordinated evaluation and joint review in a single time frame (not ad seriatim in the relevant regions). Inclusion of an interregional project in the transmission plans of relevant regions would be a prerequisite to the application of interregional cost allocation (discussed below).¹⁶

5. Cost Allocation. The NOPR proposes to more closely align transmission planning to transmission cost allocation, at least in part because FERC is concerned that the current system may not appropriately account for the benefits associated with new transmission facilities; *i.e.*, there is a potential for both free ridership and the allocation of costs to those who receive no benefit.¹⁷ The NOPR recognizes that it may be appropriate to have different cost allocation methods for facilities that are planned for different purposes. It notes, for example, that it may be appropriate to allocate costs broadly for facilities that are planned to meet regional reliability and economic needs.¹⁸

Each public utility transmission provider must have in place a method or set of methods for allocating the following costs: (i) the costs of facilities that are included in a transmission plan and, if the transmission provider is an ISO or RTO, the cost allocation method(s) should be set forth in its tariff; and (ii) the costs of new interregional projects between two planning regions.¹⁹ FERC will review cost allocation methods for intraregional and interregional facilities separately.

For intraregional facilities the NOPR requires cost allocation methods to meet the following criteria: (i) cost allocations should be roughly commensurate with

benefit, which may include maintaining reliability, sharing reserves, production cost savings and congestion relief, and meeting public policy requirements; (ii) those who do not benefit from new facilities should not be allocated costs involuntarily; (iii) if a benefit-to-cost ratio is used to determine whether facilities may be included in a regional plan for the purpose of cost allocation, such ratio may reflect a margin to account for uncertainty in the estimating process, but the ratio may not be so high as to exclude projects that offer significant benefits and any ratio in excess of 1:25 must be supported and will require express FERC approval; (iv) all costs must be allocated within the region, unless there is a voluntary agreement with an entity outside the region or another planning region but, in any event, the planning process should identify the consequences of a project for other planning regions, and the regional cost allocation method must include provisions for allocating costs imposed outside a region that the originating planning region agrees to bear; (v) cost allocation methods and data requirements must be transparent with adequate documentation for a stakeholder determine how they were applied to a project; and (vi) different cost allocation methods may be used for different purposes (*e.g.*, reliability, congestion relief, public policy driven projects).²⁰

The NOPR also states that cost allocation methods may not rely exclusively on participant funding, although they should not prohibit sponsors from funding their own projects.²¹ The NOPR does not endorse any particular intraregional cost allocation method, but notes that the “postage stamp” method may be appropriate where all customers benefit from a class or group of facilities, especially if the distribution of benefits is likely to vary over time for a project with a long life.²² A transmission provider cannot unilaterally invoke a regional cost allocation method for

a new facility located only in its own service territory, but regional funding for such a facility is allowed if the regional planning process determines that others will benefit from it.²³

For interregional facilities the NOPR requires cost allocation methods to meet the following criteria: (i) cost allocations between regions should be roughly commensurate with benefits to each region, which may include maintaining reliability, sharing reserves, production cost savings and congestion relief, and meeting public policy requirements; (ii) a region that does not benefit from facilities, currently or in the future, should not be allocated costs for the facility even if it is located in the region; (iii) if a benefit-to-cost ratio is used to determine whether facilities offer enough benefits for interregional cost allocation, such ratio may provide a margin to account for uncertainty in the estimating process, but the ratio may not be so high as to exclude projects that offer significant benefits, and any ratio in excess of 1:25 must be supported and will require express FERC approval; (iv) all costs must be allocated only to regions in which the facility is located, unless a voluntary agreement provides otherwise but, in any event, the planning process should identify the consequences of a project for other planning region, and the interregional cost allocation method must include provisions for allocating costs imposed outside a region that the originating planning region agrees to bear; (v) cost allocation methods and data requirements must be transparent with adequate documentation for a stakeholder determine how they were applied to a project; and (vi) different cost allocation methods may be used for different purposes (*e.g.*, reliability, congestion relief, public policy).²⁴ The NOPR does not endorse any particular interregional cost allocation method, and notes that interregional cost allocation methods need not match intraregional methods and that different pairs of

regions may have different methods.²⁵ The NOPR encourages multi-regional planning involving more than two regions, but does not require it.²⁶

SPP Accepts Regional Cost Allocation That Appears Similar to Approach Proposed in NOPR

On June 17, 2010, FERC also accepted for filing proposed revisions to the SPP OATT adopting the new Highway/Byway Methodology, effective June 19, 2010.²⁷

Background

Prior to implementing the Highway/Byway Methodology, SPP allocated one-third of the costs of Base Plan Upgrades²⁸ greater than \$100,000 on a postage stamp basis and the remaining two-thirds of the costs to the SPP pricing zones based on each zone's share of the incremental positive megawatt-mile benefits. SPP allocated Base Plan Upgrades that cost \$100,000 or less to the zone in which the upgrade was located. For Base Plan Upgrades associated with a wind generation resource located in the same zone as the transmission customer's point of delivery, SPP allocated costs one-third regionally and two-thirds zonally, using the megawatt-mile analysis. For Base Plan Upgrades associated with a wind generation resource located in a different zone than the transmission customer's point of delivery, SPP allocated two-thirds of the costs regionally and one-third of the costs to the transmission customer.²⁹

In response to concerns that these cost recovery methods were fragmented, confusing and difficult to administer, as well as the need to upgrade existing transmission infrastructure and build significant new transmission facilities to integrate the eastern and western portions of the SPP grid to enable renewable generation resources,

predominantly in the western part of SPP to serve load centers in the east, the SPP Board of Directors established the Synergistic Planning Project Team (SPPT) in January 2009. The SPPT was charged with examining SPP's transmission planning process and developing recommended changes. The SPPT evaluated several cost allocation approaches and ultimately recommended adopting the Highway/Byway Methodology. SPP's Regional State Committee (RSC) and cost allocation working group developed the final methodology and the OATT language implementing the Highway/Byway Methodology, though this methodology was the subject of heated opposition by many stakeholders.³⁰

Highway/Byway Methodology

Under the new Highway/Byway Methodology, Base Plan Upgrade costs will be allocated based on the voltage of the upgrade. For facilities operating at 300 kV and higher, costs will be allocated 100 percent across the SPP region on a postage stamp basis. The costs of facilities operating above 100 kV and below 300 kV will be allocated one-third on a regional postage stamp basis and two-thirds to the zone in which the facilities are located. The costs of facilities operating at or below 100 kV will be allocated 100 percent to the zone in which the facilities are located. The costs of certain upgrades that operate at two different voltages, such as transformer equipment, will be allocated based on the facilities' lower operating voltage. In addition, SPP has eliminated the megawatt-mile analysis for costs allocated to zones.

The Highway/Byway Methodology also applies to high priority upgrades (economic upgrades recommended by SPP for inclusion in the SPP Transmission Expansion Plan), excluding Balanced Portfolios that the SPP Board of Directors approve for construction, and Base Plan Upgrades associated with a Designated Resource that is a wind

generation resource, if the upgrades are located within the same zone as the transmission customer's point of delivery. Costs for Base Plan Upgrades associated with a Designated Resource that is a wind generation resource but located in a different zone than the point of delivery will be allocated under the Highway/Byway Methodology only if the upgrade facility operates at 300 kV and above. In such case, all costs will be allocated regionally. If the facility operates at less than 300 kV, 67 percent of the upgrade costs will be allocated regionally, and 33 percent will be allocated to the transmission customer.³¹

FERC Analysis

In accepting SPP's Highway/Byway Methodology, FERC found that the new cost allocation approach was driven by the need for significant expansion of the SPP transmission system due, in part, to the transition from localized transmission system operations and power markets to larger, centralized operations and regional markets, as well as state and federal policy initiatives promoting increased reliability, economically efficient transmission infrastructure development and renewable energy resources.³² FERC reiterated that up-front identification of cost allocation methods for new projects is critical "because transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs."³³

While FERC has not imposed a particular cost allocation methodology for jurisdictional transmission facilities, it has stated that the costs of such facilities must be allocated in accordance with the "cost causation" principle — rates must reflect to some degree the costs actually caused by the customer who pays them.³⁴ In Order No. 890, FERC set forth three factors it would consider when resolving disputes concerning cost allocation proposals: (1) whether

the proposal fairly assigns costs among participants, including those who cause the costs to be incurred and those that otherwise benefit from them, (2) whether the proposal provides adequate incentives to construct new transmission, and (3) whether the proposal is generally supported by state authorities and participants across the region.³⁵

Accordingly, FERC first considered whether SPP's Highway/Byway Methodology fairly assigns costs among SPP members. After agreeing with SPP that extra high voltage (EVH) facilities in the SPP region tend to support regional power flows, while lower voltage facilities provided greater support to local power flows within a single SPP zone, FERC next found that the benefits of the EVH facilities accrue to all members of the SPP transmission system.³⁶ Although the benefits "may be more appreciated at different times by different customers," FERC has consistently found that an integrated transmission network, such as the SPP system, provides benefits all users of the network.³⁷ FERC also found that, as an added measure to ensure that benefits are commensurate with costs under the Highway/Byway Methodology, SPP also revised the unintended consequences provisions in OATT Attachment J to require review of the Highway/Byway Methodology and allocation factors at least every three years (instead of every five years) and to allow the RSC to recommend any adjustments to the cost allocation if a review indicates an imbalanced cost allocation to one or more zones.³⁸

Under the second part of its three-part analysis for resolving disputes over cost allocation proposals, FERC determined that the Highway/Byway Methodology provides adequate incentives to construct new transmission. The Highway/Byway Methodology recognizes that EHV transmission facilities are regional in nature and thus assigns the costs of the facilities

to the entire region. Under the prior SPP cost allocation method, the host zone of an EHV facility would be responsible for a significant portion of the facility's costs but might not enjoy a commensurate amount of benefits.³⁹ FERC did find, however, that SPP may need to address inefficient generator siting as an unintended consequence of this cost allocation method. For example, by broadly allocating the costs of EHV facilities across a region, SPP could be encouraging members to propose EHV projects to deliver remote location-constrained resources rather than building local generation and local upgrades — even when the local project is otherwise more cost-effective. Nonetheless, FERC anticipated that this potential issue could be solved in the transmission planning process.⁴⁰

Concluding the three-part analysis, FERC found that the Highway/Byway Methodology had strong support from state authorities and SPP participants. In particular, FERC stated that SPP adopted the Highway/Byway Methodology in a manner consistent with the stakeholder process set forth in the SPP Bylaws.⁴¹

Other Issues

FERC rejected arguments that SPP did not justify certain elements of the proposal, including the allocation factors assigned to each of the voltage-based groupings of facilities, allocating the cost of certain upgrades that operate at two different voltages based on the lower operating voltage and removing the megawatt-mile analysis as a method of assigning zonal costs.⁴² FERC also rejected arguments that the SPP proposal failed to satisfy the applicable FERC filing requirements.⁴³ FERC further rejected arguments that the Highway/Byway Methodology is not just and reasonable on a stand alone basis and in isolation from the SPP transmission planning process resulting in the Integrated Transmission Plan.⁴⁴ Finally, FERC denied requests

to require SPP to restudy generator interconnections under certain circumstances relating to the change in cost allocation procedures.⁴⁵

Central Transmission Seconds Prior FERC Order Clarifying Lack of ROFR Under PJM OATT

On March 25, 2010, Central Transmission, LLC (Central Transmission) filed a complaint against PJM alleging that provisions of the PJM Operating Agreement (OA) and OATT (Tariff) are unjust, unreasonable, and unduly discriminatory to the extent that they (1) preclude PJM from designating an entity other than an incumbent transmission owner to own or construct an economic expansion included in the regional transmission plan, and (2) preclude cost-of-service rate recovery for economic projects included in the regional transmission plan that are constructed and owned by an entities other than incumbent transmission owners.⁴⁶ In December 2009, Central Transmission had submitted a proposed transmission project to PJM for study as an economic upgrade to be included in PJM's Regional Transmission Expansion Plan (RTEP).⁴⁷ Central Transmission's Complaint contended that PJM had not only failed to "provide assurances to Central Transmission that there is no impediment [in the OA and Tariff] to designating an entity other than an [incumbent transmission owner] to construct an economic upgrade," but had affirmatively indicated that impediments do exist.⁴⁸ Further, Central Transmission contended that one sentence in the RTEP protocols set forth in the PJM OA could be interpreted to preclude non-incumbent transmission owners from obtaining cost-of-service rate recovery for economic projects included in the RTEP.⁴⁹

On June 17, 2010, FERC found that, based on its earlier findings in *Primary*

Power,⁵⁰ under the current PJM OA and Tariff, Central Transmission is eligible to be designated by PJM on a non-discriminatory basis to construct, own, and receive cost-based rate recovery for an economic transmission project included in the RTEP.⁵¹ Based on these findings, the Commission dismissed the Complaint, noting that “no changes [to the PJM OA or Tariff] are necessary to respond to the issues raised [in the proceeding].”⁵² In response to certain arguments and statements made by PJM and various intervenors regarding the RTEP process and cost-based rate recovery, FERC stated, as it had in *Primary Power*, that “to the extent that PJM believes that additional tariff language would be helpful in processing [transmission developer] filings, it may make a filing under FPA section 205 to clarify its tariff.”⁵³

Endnotes

- ¹ *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Docket No. RM10-23-000, 131 FERC ¶ 61,253 (2010); 75 Fed. Reg. 37884 (June 30, 2010) (Transmission Planning NOPR or the NOPR).
- ² *Southwest Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010) (*SPP*).
- ³ 131 FERC ¶ 61,243 (2010) (*Central Transmission*).
- ⁴ Transmission Planning NOPR, 131 FERC ¶ 61,253 at P 179.
- ⁵ *Id.*
- ⁶ *Id.* at PP 163, 177, 180.
- ⁷ *Id.* at P 181.
- ⁸ *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).
- ⁹ Transmission Planning NOPR, 131 FERC ¶ 61,253 at P 45.
- ¹⁰ *Id.* at PP 49-52.
- ¹¹ *Id.* at P 64.
- ¹² *Id.* at PP 63-68.
- ¹³ *Id.* at P 70.
- ¹⁴ *Id.* at PP 90-101.
- ¹⁵ *Id.* at PP 114-117.
- ¹⁶ *Id.* at P 118.
- ¹⁷ *Id.* at P 156. *See also id.* at PP 124, 142, 153, 171.
- ¹⁸ *Id.* at P 157.
- ¹⁹ *Id.* at P 159.
- ²⁰ *Id.* at P 174.
- ²¹ *Id.* at P 168.
- ²² *Id.* at PP 165, 167.
- ²³ *Id.* at P 169.
- ²⁴ *Id.* at P 174.
- ²⁵ *Id.* at P 176.
- ²⁶ *Id.* at P 115.
- ²⁷ SPP Order, 131 FERC ¶ 61,252 at P 1.
- ²⁸ The SPP OATT defines Base Plan Upgrades as upgrades in the SPP region that are included in and constructed pursuant to the SPP Transmission Expansion Plan in order to ensure reliability, including Service Upgrades required for new or changed Designated Resources. *See* SPP OATT, Attachment J, Section III.
- ²⁹ *See Southwest Power Pool, Inc.*, Docket No. ER10-1069-000, Submission of Tariff Revisions To Modify Transmission Cost Allocation Methodology at 4-5 (filed Apr. 19, 2010) (“SPP Transmittal Letter”).
- ³⁰ SPP Order at PP 6-9.
- ³¹ *See* SPP Transmittal Letter; SPP Order at PP 10-13.
- ³² *Id.* at P 65.
- ³³ *Id.* at P 68 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 557).
- ³⁴ *Id.* at PP 66-68.
- ³⁵ *Id.* at P 69. *See also* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 559.
- ³⁶ *Id.* at PP 72-75.
- ³⁷ *Id.* at PP 78, 80.
- ³⁸ *Id.* at PP 13, 83.
- ³⁹ *Id.* at P 86.
- ⁴⁰ *Id.* at P 87.
- ⁴¹ *Id.* at P 89.
- ⁴² *Id.* at PP 94-97.
- ⁴³ *Id.* at PP 108-111.
- ⁴⁴ *Id.* at PP 116-117.
- ⁴⁵ *Id.* at PP 122-124.

⁴⁶ Complaint and Request for Expedited Action, Docket No. EL10-52-000 (filed Mar. 25, 2010) (“Complaint”).

⁴⁷ *Id.* at 7.

⁴⁸ *Id.* at 19.

⁴⁹ *Id.* at 11-12.

⁵⁰ *Primary Power, LLC*, 131 FERC ¶ 61,015 (2010) (reh’g pending) (“*Primary Power*”). *Primary Power* involved a request by a transmission developer, not already a transmission owner, for a declaratory order granting transmission incentive rates and requiring PJM to designate the developer as the entity that will construct, finance, and own the project under the RTEP. The Commission declined to require PJM to designate the developer as the entity that will construct, finance, and own the project but held, *inter alia*, that PJM “should handle the study of *Primary Power*’s application no differently than that of any other application proposing to build a project, be it an existing transmission owner or an ‘other entity,’ and would need to adequately justify its action if it denied the sponsor of the project the right to construct that project and receive the economic benefit of its project.” *Id.* at P 65.

⁵¹ *Central Transmission*, 131 FERC ¶ 61,243 at ordering paragraph.

⁵² *Id.*

⁵³ *Id.* at P 46.

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