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# *FERC NOPR on Transmission Planning, Cost Allocation, and Certain Generation Interconnection Issues*

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This Alert has been updated to reflect FERC's May 25, 2022 Notice on Requests for Extension of Time, extending the comment deadline to August 17, 2022 and reply comment deadline to September 19, 2022.

## I. Introduction

On April 21, 2022, the Federal Energy Regulatory Commission ("FERC" or the "Commission") issued a Notice of Proposed Rulemaking ("NOPR"), announcing proposed reforms to the regional transmission planning and cost allocation requirements in the *pro forma* Open Access Transmission Tariff and *pro forma* Large Generation Interconnection Agreement. The NOPR was issued after the Commission reviewed extensive comments submitted in the Commission's Advance Notice of Proposed Rulemaking ("ANOPR"), issued in July 2021 on the same subjects in the same docket. The Commission issued the NOPR in light of evidence that the Commission's regional transmission planning and cost allocation requirements are inadequate to ensure that rates remain just and reasonable and not unduly discriminatory.[1] Building off of Order Nos. 888, 890, and 1000, the Commission proposes to require public utility transmission providers[2] to conduct long-term transmission planning on a forward-looking basis to identify transmission needs in light of changing resource mixes. These proposed reforms would address the Commission's findings that transmission needs currently are largely addressed through the generator interconnection processes, which may result in inefficient expansion of the transmission system.[3] While these proposed reforms are subject to comments from interested parties, the Commission notes at various places in the NOPR where it received substantial input on certain issues to support the reforms that it now proposes.

Comments and reply comments are due August 17, 2022 and September 19, 2022, respectively.[4] Public utility transmission providers must submit a compliance filing within eight months of the effective date of any final rule in this proceeding.[5] Transmission providers that are not public utilities will also adopt the NOPR's requirements to satisfy reciprocity requirements in Order No. 888.[6]

## II. Regional Transmission Planning

### *A. Long-Term Regional Planning*

*1. Background*

Under the existing regional transmission planning process, public utility transmission providers plan their transmission systems to meet reliability, economic, and Public Policy Requirement needs. The reliability and economic needs are identified through planning studies, whereas public utility transmission providers are afforded flexibility in identifying Public Policy Requirement needs.

*2. Identification of Transmission Needs*

In the NOPR, FERC expressed concern that existing regional transmission planning fails to consider sufficiently long-term, forward-looking initiatives such as changing resource mix and consumer demand. As a result, FERC noted that current transmission planning has resulted in piecemeal and inefficient development of new transmission facilities.

*a. Development of Long-Term Scenarios for Use in Long-Term Regional Transmission Planning*

To remedy this piecemeal approach, FERC proposes to require public utility transmission providers to participate in Long-Term Regional Transmission Planning. Specifically, FERC proposes to require that public utility transmission providers in each transmission planning region comply with the following five requirements:

1. Use a transmission planning horizon of at least twenty years into the future to develop Long-Term Regional Transmission Planning Scenarios, which must be updated every three years;
2. Incorporate a set of Commission-identified factors into their Long-Term Scenarios;
3. Develop a plausible and diverse set of at least four Long-Term Scenarios;
4. Use "best available data" in developing Long-Term Scenarios; and
5. Consider whether to identify geographic zones with the potential for development of large amounts of new generation.[7]

Notably, public utility transmission providers may continue to rely on their existing regional transmission planning and cost allocation processes to comply with Order No. 1000's reliability and economic requirements. However, FERC *has* proposed to require public utility transmission providers to amend the regional transmission planning processes in their OATTs to "explicitly describe the open and transparent process [they] will use to develop Long-Term Scenarios."[8] In order to satisfy FERC's proposed requirements for Long-Term Scenario planning, public utility transmission providers must incorporate seven prescribed categories of factors.[9]

Public utility transmission providers would need to publish on OASIS a list of the specific factors that fall into each category of factors, as incorporated into their development of Long-Term Scenarios. The inputs for each scenario must also be publicly disclosed in order to give stakeholders the opportunity to understand the scenarios and provide meaningful input.

FERC also offered guidance on how public utility transmission providers could effectively develop Long-Term Scenarios proposed in the NOPR. FERC suggested that providers create a base case, "business-as-usual" scenario, and then create alternative scenarios with different assumptions that are less likely to occur.[10] FERC does not propose to require utilities to conduct specific types of scenarios or assess the likelihood of each scenario actually occurring, so long as each scenario is "plausible."[11] At least one of the four scenarios, however, must account for a "high-impact, low-frequency event" such as extreme weather events or cyber-attacks.

The Long-Term Scenarios would need to be updated at least once every three years. In doing so, public utility transmission providers would need to update all data inputs each time they update their Long-Term Scenarios. FERC proposed that these updates must use "best available data inputs," defined as data inputs that are timely, developed using diverse and expert perspectives, adopted via transparent processes, and reflective of the seven factors that must be incorporated into Long-Term Scenarios.[12]

Finally, public utility transmission providers would be required to identify geographic zones with the potential for development of large amounts of new generation. This requirement is intended to assist developers and public utility transmission providers in coordinating their activities to make investments in geographic areas likely to experience large growth. FERC's proposal would require public utility transmission providers to consider whether to (1) identify specific geographic zones within the transmission planning region that have potential for large amounts of new generation; (2) assess generation developers' commercial interest in developing generation within the identified geographic zones; and (3) incorporate designated zones, and the identified commercial interest in each zone, into Long-Term Scenarios.[13] Public utility transmission providers would need to provide a meaningful opportunity for input from federal and state siting authorities in order to better anticipate any development challenges associated with identified high-growth zones.

*b. Evaluation of the Benefits of Regional Transmission Facilities*

Once public utility transmission providers have identified transmission needs through Long-Term Scenarios, the Commission proposes to require providers to evaluate the benefits of their regional transmission facilities over a minimum of a 20-year time horizon.[14] FERC selected a 20-year time period because it strikes a reasonable balance between acknowledging many transmission facilities have useful lives that can exceed 40 years, and recognizing inherent difficulties in predicting system conditions many decades in the future.

Consistent with Order No. 1000, the Commission declined to prescribe any particular definition of "benefits" or "beneficiaries," nor require consideration of specific benefits.[15] However, the Commission did create a list of proposed Long-Term Regional Transmission Benefits that public utility transmission providers may consider in their long-term planning.[16]

FERC proposed to require public utility transmission providers to identify the benefits considered and explain how the benefits are calculated. FERC also observed that many of the transmission planning processes already used by RTOs/ISOs and non-RTO/ISO providers alike incorporate some or all of these benefits into their cost-benefit analyses.

FERC also proposes to afford public utility transmission providers in each region the flexibility to use a portfolio approach in evaluating the facility benefits identified through Long-Term Regional Transmission Planning.[17] In doing so, FERC will not require public utility transmission providers to run separate analyses for each and every facility they own, but instead will allow public utility transmission providers to holistically plan out larger subsets of their transmission systems.

*c. Selection of Regional Transmission Facilities*

In response to comments regarding whether and how public utility transmission providers should use information developed through long-term scenario planning to identify and select transmission facilities that meet future needs, FERC proposes to require public utility transmission providers to coordinate with relevant state entities in developing transparent and not unduly discriminatory criteria for selecting the projects that will be included in the regional transmission plan. The Commission emphasized the importance of coordination with state entities, because resource mix goals and other policy decisions may vary from state to state, even within a larger overall transmission-planning region.

*3. Consideration of New Technology*

The Commission also noted the commercial availability of technologies which could be used in regional planning processes to aid in the identification of more cost effective regional transmission facilities, to help ensure that jurisdictional rates are just and reasonable.[18]

In the NOPR, the Commission proposed to require public utility transmission providers to more fully consider facilities that use dynamic line ratings and advanced power flow control devices in regional transmission planning and cost allocation processes.[19] The Commission identified that the use of these technologies could provide greater production cost benefits under transmission outage scenarios as compared to other facilities that do not utilize those technologies.[20] In all aspects of the regional transmission planning process for near-term regional transmission needs and Long-Term Regional Transmission Planning, public utility transmission providers would evaluate whether incorporating these technologies into existing facilities could meet the same regional transmission needs more efficiently or cost-effectively than other potential facilities and whether incorporating these technologies as part of any regional transmission facility would be more efficient or cost-effective.[21]

The Commission seeks feedback on this proposal. It also seeks comment on whether other technologies should be included and whether non-RTO/ISO transmission planning regions should update their energy management systems to make similar changes.[22]

If adopted, the consideration of facilities that use dynamic line ratings and advanced power flow control devices could improve the operation of transmission facilities and help ensure that jurisdictional rates are just and reasonable through the improved operation of transmission facilities and deferring new transmission investments.

### *B. Amendments to Order No. 1000*

In Order No. 1000, the Commission eliminated all federal rights of first refusal ("ROFR") for regional transmission facilities selected in a regional transmission plan. In one of the more controversial elements of Order No. 1000, FERC transitioned from permitting RTO Tariffs to contain rights of first refusal by default for incumbent transmission owners to hold exclusive rights to build transmission projects within their own footprints, to the introduction of competition for a large category of projects with regional benefits regardless of the footprint of the project. Order No. 1000 excepted certain "local" and reliability-focused projects from the rule, continuing to reserve those for incumbents.

In the NOPR, the Commission referenced that investment trends since Order No. 1000 indicate that the *complete* elimination of the federal ROFR caused perverse investment incentives. Delays and costs related to transmission solicitation processes appeared to have encouraged otherwise uneconomic construction of the "local" classification of facilities to avoid a competitive process. As a result, the Commission observed that "recent investment appears to be concentrated in transmission facilities not subject to [competitive solicitations under] Order No. 1000" as opposed to investment in regional facilities.[23]

FERC referenced commenters' concerns in unveiling a new class of projects that could be subject to federal ROFRs. In what could be seen as offering middle ground between the complete elimination of the federal ROFR in favor of competition, the Commission proposed to allow "conditional" federal ROFR for certain Jointly Owned Transmission Facilities for regional facilities where the incumbent must join with a non-incumbent investment partner in order to exercise its ROFR. Citing examples of successful projects identified by commenters,[24] FERC proposed that incorporating such a concept in regional transmission plans could decrease financing and siting risks, spread financial risks among multiple parties, and could help ensure timely construction of needed transmission projects. While FERC offered high-level guidelines for its conception of how the process would work, it solicits feedback from industry on eligibility for partners and processes in connection with the proposal.

The proposal's adoption could lead to greater opportunities for entities not affiliated with public utility transmission providers to meaningfully access investment in what is otherwise an industry with very high barriers to entry, and where participation in competitive processes can be risky and cost-prohibitive. On the other hand, the proposal could lead to a new class of controversies if tariff rules are unclear regarding processes or eligibility criteria.

### *C. Certain Interconnection Reforms*

Curiously, the Commission dedicated only 22 paragraphs of the 465-paragraph NOPR to discussing generation interconnection. Why would the Commission include a seemingly cursory section on interconnection in a NOPR focused on transmission issues, especially when Chairman Glick announced at the Commission's April 21 public meeting that a NOPR focusing on interconnection issues would likely be forthcoming within a month or so?

The answer lies in part with comments submitted in response to the ANOPR. Some generators at that time pointed out situations where a transmission upgrade was part of the public utility transmission provider's long-term transmission plan, but was not planned to be built until years later. In the meantime, generators often submit an interconnection application that has triggered, according to the public utility transmission provider, the transmission upgrade to be built sooner than planned. Notwithstanding that the transmission project was part of a long-term transmission plan, the generation project triggered the need sooner than scheduled, and the costs of Network Upgrades would be allocated solely to the generator. If the upgrade been built per the public utility transmission provider's plan, the costs would have been socialized. The Commission noted that such accelerated Network Upgrades were frequently costly. In many cases, the generators backed out of their generation project and entirely withdrew from the queue, in large part due to being directly assigned the costs of an expensive Network Upgrade. The Commission realized that there is a real need to better coordinate regional transmission planning and cost allocation with generator interconnection processes.

To enhance such coordination, the Commission proposes to require that public utility transmission providers consider, as part of their Long-Term Regional Transmission Planning, regional transmission facilities that address interconnection-related needs identified multiple times in the generator interconnection process, but that have never been constructed due to the withdrawal of the underlying interconnection request(s).[25]

In particular, the Commission proposed to require that public utility transmission providers evaluate regional transmission facilities for selection in the regional transmission plan in order to address interconnection-related needs that have been identified in the generator interconnection process as requiring interconnection-related network upgrades.[26]

Such interconnection needs would need to be included in the Long-Term Regional Transmission Planning where:

> (1) the public utility transmission provider has identified interconnection-related network upgrades in interconnection studies to address those interconnection-related needs in at least two interconnection queue cycles during the preceding five years (beginning at the time of the withdrawal of the first underlying interconnection request); (2) the interconnection-related network upgrade identified to meet those interconnection-related needs has a voltage of at least 200 kV and/or an estimated cost of at least $30 million; (3) those interconnection-related network upgrades have not been developed and are not currently planned to be developed because the interconnection request(s) driving the need for the upgrade has been withdrawn; and (4) the public utility transmission provider has not identified an interconnection-related network upgrade to address the relevant interconnection-related need in an executed generator interconnection agreement or in a generator interconnection agreement that the interconnection customer requested that the public utility transmission provider file unexecuted with the Commission.[27]

The Commission noted evidence of a sharp growth in both the total costs of interconnection-related network upgrades and the cost of such upgrades relative to generation project costs. Related evidence demonstrates that the average cost of interconnection-related network upgrades is "increasing over time as the transmission system is fully subscribed and demand for interconnection service outpaces transmission investment."[28] In recognition of such evidence of dramatically increased costs of interconnection-related upgrades, the NOPR provides that for the purposes of cost allocation of such facilities selected for inclusion in the regional transmission plan, such inclusion would "provide an avenue to allocate these regional transmission facilities' costs more broadly in recognition of their more widespread benefits (as identified through the regional transmission planning process), helping to ensure that their costs are allocated in a manner that is at least roughly commensurate with the estimated benefits that they provide."[29]

Some generator commenters may well applaud the Commission for tackling this thorny network upgrade/cost allocation issue, but seek a lower voltage level and/or a dollar threshold under $30 million. Generators also may seek a much stronger statement that costs of network upgrades identified in the regional transmission plan as well as in response to a generator's interconnection request should be totally socialized, and not directly allocated in part to the generator. Public utility transmission Provider commenters may argue both that the voltage level should be raised much higher (perhaps as high as 345 kV), and that the dollar threshold should be increased as well.

In any event, the Commission's proposal for better coordination of interconnection upgrade processes, regional transmission planning, and cost allocation will not likely result in overnight remedies or immediate breakthroughs where more generators will stay in the queue even though costly network upgrades have been identified. Instead, this is another area where the rules, if adopted, could lead to a softer, long-term landing zone, where there is a much more coordinated review of network upgrade needs in both the generation interconnection and regional transmission planning processes.

### *D. Enhanced Transparency in Regional Transmission Planning*

Under the current FERC process, the analysis of local transmission plans is limited to a reliability analysis, which provides minimal opportunity for stakeholder review. The Commission considered ANOPR comments lamenting a lack of visibility into the local transmission planning process, which has been the province of incumbent transmission owners and state commissions. In many instances, local transmission facilities are replaced as "in-kind" replacements, and these facilities are not part of the regional transmission process unless the transmission owner sought to have the replacement facility included in the regional transmission process for cost allocation purposes. Some commenters thought the local transmission planning process should be more transparent, as higher voltage transmission facilities that serve regional needs may be more appropriate than just replacing a lower voltage facility that is deemed to serve only a local function. Other commenters wanted the local transmission process to remain the province of the incumbent utility with state commission oversight, "arguing that the Commission should not intervene in retail activities that are subject to state-level regulatory bodies."[30]

The Commission's proposed reform focuses on increasing transparency of the local transmission planning process as part of the regional transmission process, and increasing coordination between the regional and local transmission processes. Each public utility transmission provider would be required to revise its regional plan to include: (i) the criteria, models, and assumptions used in its local transmission planning process, (ii) local transmission needs that it identifies through that process and (iii) the potential local or regional transmission facilities that it will evaluate to address those local transmission needs.[31]

The Commission proposed more prescriptive requirements as part of this greater coordination between local and regional planning. Each public utility transmission provider will need to hold at least three stakeholder meetings and post relevant information to enable stakeholders to submit comments. The three meetings are designated as the: (i) Assumptions meeting—review of the criteria, assumptions and models related to each public utility transmission provider's local planning; (ii) Needs meeting—review of reliability criteria violations and local transmission planning drivers (to be held fewer than 25 days after the Assumptions meeting); and (iii) Solutions meeting—review the range of potential solutions to address reliability criteria violations and transmission needs.[32]

To address the concern over automatic in-kind replacement of local transmission facilities without sufficient input on regional facility options, the Commission proposes to require that public utility transmission providers in each transmission planning region evaluate whether facilities operating at or above 230 kV that an individual public utility transmission provider anticipates replacing during the next 10 years can be "right sized" "to more efficiently or cost-effectively address regional transmission needs identified in Long-Term Regional Transmission Planning."[33] Right sizing could include increasing the facility's voltage level, adding circuits to the towers, or incorporating advanced technologies.

These proposals will likely elicit significant comments, both with regard to a concern by some that the local transmission planning process may be delayed or unnecessarily modified, and with regard to the proposed 230 kV voltage level and the proposed 10-year period.

## III. Regional Transmission Cost Allocation

### *A. Reform to Cost Allocation Methods*

In Order No. 1000, FERC established requirements for cost allocation of new transmission facilities selected in regional transmission plans and established six cost allocation principles that must be met.[34] Together, these six principles were intended to ensure that the costs of new transmission facilities would be allocated in a manner roughly commensurate with their benefits. FERC did not require adoption of a universal or comprehensive definition of "benefits," instead permitting regional flexibility.

In the NOPR, the Commission recognizes the ongoing challenges in finding a fair cost allocation method for regional transmission facilities, especially in planning regions encompassing several states.[35] Given the increased complexity of long-term transmission planning, the Commission proposes to deviate from Order No. 1000 by providing state regulators with a formal opportunity to develop cost allocation methods.[36] The Commission justifies its concession to state agencies by pointing out that states can (and do) use their siting authority to block projects they view as inconsistent with their ratepayers' interests. The Commission claims its proposal may increase the likelihood that facilities are sited and ultimately developed with fewer costly delays.[37] In doing so, the Commission made efforts to show "broad agreement on the importance of states' role in cost allocation."[38] The Commission also recognized support for adoption of a wider set of benefits used to evaluate projects.[39]

Three broad sets of changes are proposed, as outlined below:

First, the Commission proposes to require cost allocation of Long-Term Regional Transmission Facilities using either (1) a Long-Term Regional Transmission Cost Allocation Method (defined as an *ex ante* approach), (2) a State Agreement Process (defined as an *ex post* approach), or (3) a combination of the two.[40] Under the State Agreement Process, after a Long-Term Regional Transmission Facility is selected, the State Agreement Process would be followed to establish a cost allocation method for that facility.[41] The filing entity must therefore explain the process by which state entities would reach voluntary agreement if using the State Agreement Process.[42] The filing entity must also seek agreement by the relevant state entities on which method to adopt, and if agreement is not reached, the filing entity must explain the good faith efforts made to seek agreement.[43]

Of note, the Commission recognized that the reliance of the State Agreement Process on participant funding raises free ridership concerns, where beneficiaries of a project may defer investment in hopes that others fund the project first.[44] The Commission stated that an *ex ante* cost allocation method is better at ensuring development of more efficient or cost-effective projects.[45] However, the Commission believes that the benefits of greater state involvement outweigh such concerns.[46]

Second, the Commission proposed a requirement to allow states a time period in which to negotiate a cost allocation method for a transmission facility that is different than any *ex ante* regional cost allocation method that would otherwise apply.[47] In other words, even if a State Agreement Process is not adopted, the states will still be given an opportunity to reach agreement on a preferred cost allocation method for specific projects. Such a method, if agreed to unanimously, could then be filed for FERC approval.[48]

Finally, the Commission recognized concerns by commenters that the existing regional transmission planning and cost allocation requirements may undervalue the benefits of long-term transmission facilities. Specifically, the current approach only considers a subset of benefits based on the type of transmission need being studied, which may result in an inaccurate valuation.[49] Thus, the Commission proposes to require creation of a common set of Long-Term Regional Transmission Benefits and to require that each filing utility identify the specific benefits they will use in any *ex ante* cost allocation method.[50]

### *B. CWIP Incentive*

In response to the Energy Policy Act of 2005, FERC issued Order No. 679 to promote capital investment in transmission infrastructure through incentive-based rate treatments. The Commission found that the long-lead time to construct new transmission facilities created cash flow difficulties that could impede new investment in transmission. Thus, the Commission created an incentive to allow for the recovery of 100% of Construction Work in Progress (CWIP) incentive in rate base, subject to certain conditions and approval in a Section 205 filing. The alternative to the CWIP incentive is to book construction and pre-construction costs to Allowance for Funds Used during Construction (AFUDC), which permits recovery only after the project is in service.

In its NOPR, the Commission preliminarily finds that granting the CWIP incentive for Long-Term Regional Transmission Facilities may "shift too much risk to consumers to the benefit" of transmission developers.[51] Due to the increased uncertainty of long-term projects, the Commission believes the risk is greater that such facilities may not become "used and useful," and proposes to not permit public utility transmission providers to take advantage of the CWIP incentive for Long-Term Regional Transmission Facilities. AFUDC would still be available, however, as the allowable method for rate recovery.

If adopted, the Commission's proposal will lead to lower rates in the short run, as transmission owners will be unable to recover costs for long-term transmission facilities until they are placed in service. Transmission owners who achieve commercial operation, however, will be able to earn a greater return than if they recovered under the CWIP incentive.

## IV. Interregional Transmission Coordination Procedures

The Commission considered comments addressing the value and logistics for enhanced interregional transmission coordination, planning, and cost allocation. In noting the continued significant need for interregional transmission coordination to identify cost-efficient solutions in transmission planning, the Commission proposes that public utility transmission providers revise their existing interregional transmission coordination procedures to apply them to the Long-Term Regional Transmission Planning reforms proposed in the NOPR.

Specifically, in implementing the reforms in the NOPR as part of the interregional planning processes, public utility transmission providers would (i) share information regarding the respective transmission needs identified in the Long-Term Transmission Plans and proposed transmission projects, and (ii) identify and evaluate interregional transmission facilities that could more efficiently or cost-effectively meet the transmission needs identified through the Long-Term Regional Transmission Planning process. Additionally, the Commission proposes requiring public utility transmission providers in neighboring transmission planning regions to revise their interregional transmission coordination procedures (and regional transmission planning processes as needed) to allow for proposing an interregional transmission facility as a potential solution to transmission needs identified through Long-Term Transmission Planning.

## V. Conclusion

The NOPR builds on Order Nos. 888, 890, and 1000 to ensure the significant transmission planning and cost allocation reforms of the past 25 years are reflected in FERC's transmission policies. The NOPR does this through proposed reforms to long-term regional transmission planning, regional transmission cost allocation, and interregional transmission coordination and cost allocation. Industry participants should stay apprised of these important transmission policy developments and can take an active stakeholder role by submitting comments on the proposals outlined by the Commission in the NOPR.

We continue to monitor opportunities to engage with the Commission on matters affecting clients' interests and are actively following this proceeding and other areas within the Commission's jurisdiction that may be impacted by the NOPR.

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[1] *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 at P 24 (2022) ("NOPR").

[2] The NOPR makes clear that the term "public utility transmission provider" refers to transmission providers who own or operate facilities subject to the Commission's jurisdiction. *Id.* at P 3, n. 5 (citing 16 U.S.C. § 824(e)).

[3] *Id*. at P 42.

[4] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Notice on Requests for Extension of Time, Docket No. RM21-17-000, at 2 (May 25, 2022).

[5] *Id.*

[6] *Id.* at P 432.

[7] *Id*. at P 91.

[8] *Id.* at P 85.

[9] The categories of factors are: (1) federal, state, and local laws and regulations that affect future resource mix and demand; (2) federal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved utility integrated resource plans and expected supply obligations for load serving entities; (4) trends in technology and fuel costs within and outside of the electric supply industry, including shifts toward electrification of buildings and transportation; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand. *Id*. at P 104.

[10] *Id*. at PP 122-123.

[11] *Id.* at P 123.

[12] *Id*. at P 130.

[13] *Id*. at P 145.

[14] *Id*. at P 175.

[15] *Id*. at P 183.

[16] The proposed benefits are: (1) avoided or deferred reliability transmission projects and aging infrastructure replacement; (2) either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced

transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme events and system contingencies; (7) mitigation of weather and load uncertainty; (8) capacity cost benefits from reduced peak energy losses; (9) deferred generation capacity investments; (10) access to lower-cost generation; (11) increased competition; and (12) increased market liquidity. *Id*. at P 185.

[17] *Id*. at P 233.

[18] *Id.* at P 267.

[19] *Id.* at P 272.

[20] *Id.* at P 273.

[21] *Id.* at P 274.

[22] *Id.* at P 277.

[23] *Id.* at P 349

[24] *Id.* at PP 360-364

[25] *Id*. at P 166.

[26] *Id*.

[27] *Id*. (emphasis added).

[28] *Id.* at P 38.

[29] *Id*. at P 168.

[30] *Id*. at P 397.

[31] *Id.* at P 400.

[32] *Id.* at P 401.

[33] *Id*. at P 403.

[34] The six cost allocation principles are: (1) the costs of transmission facilities selected in a regional transmission plan for purposes of cost allocation must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits; (2) those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities; (3) a benefit to cost threshold ratio, if adopted, cannot exceed 1.25 to 1; (4) costs must be allocated solely within the transmission planning region unless another entity outside the region voluntarily assumes a portion of those costs; (5) the method for determining benefits and identifying beneficiaries must be transparent; and (6) there may be different regional cost allocation methods for different types of transmission facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements. Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 637, 646, 657, 668, 685.

[35] NOPR at P 297.

[36] *Id.* at P 299.

[37] *Id.* at PP 299-314.

[38] *Id.* at PP 289-90.

[39] *Id.* at PP 291-292.

[40] *Id.* at P 302.

[41] *Id.* at P 302 n.509.

[42] *Id.* at P 313.

[43] *Id.* at P 303.

[44] *Id.* at PP 316-317.

[45] *Id.* at P 315.

[46] *Id.* at P 317.

[47] *Id.* at P 319.

[48] *Id.* at P 319.

[49] *Id.* at P 325.

[50] *Id.* at P 326.

[51] *Id.* at P 332.