

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Remedying Undue Discrimination)
Through Open Access Transmission Service) Docket No. RM01-12-000
And Standard Electricity Market Design)

REPLY COMMENTS OF NATIONAL GRID USA

National Grid USA (“National Grid”) respectfully submits the following Reply Comments in response to comments submitted by various parties on the Federal Energy Regulatory Commission’s (“Commission”) July 31, 2002, Notice of Proposed Rulemaking (“NOPR”)¹ regarding Network Access Service and Standard Market Design (“SMD”). On November 15, 2002 and January 10, 2003 National Grid submitted comments on certain issues raised by the NOPR. National Grid now submits these Reply Comments to address a limited number of issues raised in comments on the NOPR by other parties, and to urge that the Commission move forward with the sound policy objectives set forth in the NOPR, with certain enhancements to ensure that the Commission’s final SMD rule will promote the development of the robust transmission infrastructure needed to facilitate development of a truly competitive wholesale power market.² National Grid urges the Commission to adopt these enhancements in its forthcoming SMD white paper and in the final rule on Network Access Service and Standard Market Design.

¹ *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, 100 FERC ¶ 61,138, FERC Stats. & Regs., Proposed Regs. ¶ 32,563 (2002).

² Pursuant to the Notice on Requests for Additional Time issued in this proceeding on December 20, 2002, National Grid is submitting these Reply Comments by the deadline established for parties requiring additional time to consider the issues raised by other parties.

I. EXECUTIVE SUMMARY

National Grid strongly supports the Commission's ambitious goal of creating geographically broad regional electricity markets that are workably competitive and economically efficient. At the same time, National Grid believes that the most serious barriers to achieving this goal stem from the fact that the current transmission system does not provide an adequate platform for unconstrained competitive regional power markets. Constraints in the transmission network limit the geographic scope of markets and shelter many suppliers from competitors. To successfully implement its market-based vision for the electricity industry, the Commission must structure its SMD initiative – including any interim requirements – in a manner that fosters the most rapid possible development of a robust transmission network that can serve as a secure and reliable platform for market activity.

In its previous comments, National Grid proposed a number of modifications to bring the NOPR into harmony with the Commission's objectives of efficient competitive regional electricity markets supported by non-discriminatory access to a strong and reliable transmission network. While most of the comments submitted by other parties in this proceeding are consistent with National Grid's proposed modifications, others suggest changes to the SMD rule that we believe would substantially undercut the Commission's objectives.

In these Reply Comments, National Grid addresses the following issues:

- The SMD transmission planning process should address both economic and reliability needs, and should reflect the reality that the large majority of needed transmission upgrades will be built by incumbent transmission owners, because merchant transmission will be unable to address most transmission system needs. The process should not rely on Congestion Revenue Rights ("CRRs") or CRR shortfall funding obligations to induce sufficient transmission construction, and should eliminate any

requirements for the Independent Transmission Provider (“ITP”) to engage in a duplicative and delay-prone formal request for proposals (“RFP”) process.

- The Commission’s transmission pricing policy should include a mechanism for new transmission that efficiently allocates transmission costs to the beneficiaries of transmission projects based on a pragmatic *ex ante* classification of transmission upgrades. These classifications should be based on the functions that particular classes of upgrades perform, thus avoiding the many shortcomings of a “participant funding” model that requires case-by-case identification of the beneficiaries of all or most transmission upgrades. One serious shortcoming of the “participant funding” approach is its encouragement of free riders who wait out the participant funding process in the hope of benefiting without paying. The Commission should also reject comments urging the Commission to abrogate pre-Order No. 888 transmission contracts – including bilateral agreements for the funding of controllable inter-market transmission interties – under the guise of eliminating rate pancaking.
- In developing the SMD Resource Adequacy requirements, the Commission should recognize that only a regional deliverability requirement of the kind employed in PJM will promote the improvements to the national transmission grid needed to help fulfill the Commission’s vision of geographically broad energy markets. The Commission should avoid locational capacity mechanisms that institutionalize small, insular electricity markets, thus requiring indefinite application of market mitigation procedures to protect against market power. The Commission should also ensure that any resource adequacy mechanism will enable load-serving entities (“LSEs”) to maintain the benefits of the bargains they have struck or will strike in bilateral capacity contracts.
- The Commission should clearly reaffirm that implementation of SMD does not require any reduction in those functions it has already authorized Independent Transmission Companies (“ITCs”) to undertake, and should take into account the advice of financing experts that a robust ITC functionality is needed to support investment in the independent transmission sector.

II. COMMENTS

A. Transmission Planning and Pricing

In its January 10, 2003, comments in this proceeding (“January 10 Comments”), National Grid endorsed the NOPR’s proposal for a regional transmission planning process that addresses both reliability and economic needs. A robust, streamlined planning process that relies primarily on incumbent regulated transmission owners to construct needed transmission facilities is critical to the success of SMD, because market-

based merchant projects funded by CRRs or other mechanisms are unlikely to address more than a small part of the well-documented shortfall of investment in the nation's transmission infrastructure. National Grid's January 10 Comments also emphasized the need for a pricing policy for new transmission that will facilitate rather than impede the development and construction of such needed transmission upgrades. The Commission should abandon the proposed "participant funding" mechanism, which would fail to encourage needed transmission construction due to the natural reluctance of "participants" to volunteer to pay for the very high costs of such construction. "Participant funding" would also result in substantial delays, controversy, and litigation arising from disagreement over the ITP's case-by-case determinations of which participants do and which do not benefit from a given transmission project.

A number of commenters support proposals that National Grid believes would preclude an effective planning process supported by a pragmatic cost allocation mechanism that assigns transmission costs to transmission project beneficiaries. National Grid advocates a system that uses *ex ante* classifications of transmission upgrades for determining cost allocation. National Grid offers the following responses to a number of specific comments on these issues:

- 1. The NOPR Appropriately Proposes a Robust Regional Planning Process Which Addresses Both Reliability and Economic Needs.**

Although many commenters recognize that a truly effective transmission planning process must address both reliability and economic needs,³ others propose that the ITP

³ See, e.g., January 10, 2003, Comments of Constellation Energy Group, Inc. at 10-11; January 10, 2003, Comments of Coalition of Midwest Transmission Customers, *et al.* at 24; January 23, 2003, Comments of WPS Resources Corp. at 27; and January 10, 2003, Comments of Coalition of the American Public Power Association at 15-20.

should plan only for reliability needs.⁴ Some of these latter commenters suggest that the ITP be denied authority to plan for projects that would address identified economic needs (*i.e.*, transmission upgrades that will create more competitive markets and/or reduce energy costs resulting from transmission constraints). Others contend that there is no need for the ITP to have such authority because Locational Marginal Pricing (“LMP”) and associated CRRs will provide sufficient economic signals for most needed transmission to be constructed on a merchant basis.⁵

The adoption of such proposals would eliminate one of the most significant benefits of the SMD transmission planning process – the mechanism by which the ITP can ensure the construction of transmission upgrades that will, over time, (1) eliminate load pockets, (2) enlarge and integrate geographically limited markets, and (3) limit the exercise of locational market power that drives up the costs of energy. Without a construction mechanism that encompasses both reliability and economic upgrades, critically needed infrastructure may not be planned and built, and truly competitive wholesale energy markets can never be fully realized.

Even in regions where an LMP-based market structure exists, the lack of a regional planning mechanism to address transmission constraints with substantial economic impacts will perpetuate balkanized energy markets. As numerous parties have informed the Commission,⁶ the award of congestion revenues or CRRs to merchant developers who build transmission capacity in an LMP-based energy market will be

⁴ See, *e.g.*, January 10, 2003, Comments of the New York Transmission Owners at 13; January 22, 2003, Comments of Central Maine Power Co., *et al.* at 4, 8-10.

⁵ See, *e.g.*, January 10, 2003, Comments of Exelon Corp. at pp. 19-20.

⁶ See *e.g.* December 20, 2002, Comments of the U.S. Department of Energy at 6; January 10, 2003, Comments of Keyspan Corporation at 14; January 10, 2003, Comments of Old Dominion Electric Cooperative at 5-6.

insufficient to induce transmission capacity adequate to customers' economic needs. The SMD NOPR comments submitted by Professor Paul L. Joskow include an extensive analysis of an approach to regional transmission planning that relies primarily upon such merchant transmission to meet future investment needs, and concludes that such an approach fails to reflect many important economic and physical attributes of transmission investment, and is inconsistent with sound economic theory.⁷ Professor Joskow concludes that the "one internationally proven way to stimulate transmission investment is to rely primarily on incumbent regulated transmission network owners operating under sound regional planning guidelines."⁸

Certain commenters argue that builders of new transmission on a merchant basis have the ability to capture the benefits of lower LMPs resulting from the project, which, when added to CRR revenues, should be sufficient to induce developers to build adequate transmission.⁹ However, because of the constantly changing nature of the market, and the fact that free riders can often appropriate much of the LMP benefit associated with new transmission, no merchant developer can or should count on capturing such benefits for itself, and the Commission should not assume that they will do so. Thus, the nature of the benefits and free rider issues of new transmission will undermine any regional planning process that places excessive reliance on participant-funded projects to produce an efficient, robust transmission infrastructure.

Experience in regions that have implemented LMP confirms this conclusion. For example, in New York, which has had an LMP-based market since 1999, the heavily

⁷ Comments of Paul L. Joskow, dated January 10, 2003, at 51-58 ("Joskow Comments"). The Commission should note that Professor Joskow's comments were actually filed on January 8, 2003.

⁸ *Id.* at 10.

congested interfaces between upstate New York and downstate New York, as well as localized transmission constraints into New York City and Long Island, have resulted in the division of the state into a number of sub-optimal, insular energy markets.¹⁰ As a result, there is currently extensive use of market mitigation rules and import restrictions into congested zones in order to “make” these markets work. New York’s congestion costs have averaged over \$850 million a year since 2000.¹¹ In addition, an estimated \$150 million a year of additional ICAP costs are paid by consumers due to the existence of locational ICAP rules and the lack of sufficient transmission to connect upstate New York to the City and Long Island.¹² The amount of economically justified transmission investment that would reduce or eliminate these losses can be as high as \$5 billion (assuming a 20% carrying charge factor). But because the New York ISO lacks the regional planning process to ensure consideration of transmission upgrades to economically alleviate these heavily congested facilities, significant constraints persist in spite of these price signals.

PJM is another region that illustrates that LMP alone, or even in conjunction with a regional deliverability requirement, is unlikely to result in merchant transmission investment in the amount needed to address economic needs. Although PJM has implemented LMP-based energy markets for over four years, along with a robust regional

⁹ See January 10, 2003, Comments of Entergy Services, Inc. at 8-9. This purported capture of benefits is sometimes referred to as the “infra-marginal benefit” of building transmission.

¹⁰ See, e.g., Commission Staff November 1, 2000, *Investigation of Bulk Power Markets – Northeast Region* at pp. 1-10 to 1-11. This report is posted on the Commission’s web site at: <http://www.ferc.gov/electric/bulkpower/northeast.pdf>.

¹¹ “NYISO 2002 Overall Performance: State of the System,” presented by W.J. Museler, October 15, 2002, Joint New York Independent System Operator Board of Directors and Management Committee Meeting, slide 14. This presentation is posted on the New York ISO’s web site at: http://www.nyiso.com/services/documents/groups/mgmt_comm/meeting_materials.html.

¹² This estimate is based on average ICAP clearing prices of approximately \$10/kw-month in New York City and Long Island and \$3/kw-month in Upstate New York, as against an assumed region wide

deliverability requirement, congestion costs have doubled every year, while transmission construction has not even kept pace with load growth.¹³ Indeed, it appears that only PJM's regional deliverability requirement for new capacity resources has kept PJM from falling even further behind in constructing transmission capacity to reduce congestion costs. However, a regional deliverability requirement by itself cannot solve the problem in the absence of a planning process that takes account of economic as well as reliability needs.

For example, more than two years after the Commission acknowledged the exceptionally high congestion costs incurred by some LSEs on the Delmarva Peninsula in PJM and acted on a complaint by finding that PJM lacked sufficient incentives or procedures to address the inadequate transfer capability into the load pocket on the Peninsula,¹⁴ the exceptionally high congestion costs to customers on the Peninsula continue to persist.¹⁵ To date, merchant developers have not responded to these high congestion costs through either the addition of transmission capacity or generation. This is an example of the perpetuation of load pockets that can occur in a region that has LMP-based energy markets and a regional deliverability requirement – which National Grid supports – but lacks a regional planning process to address economic needs.

Professor Joskow's comments include an analysis of the capital and operating costs of PJM's transmission network, which illustrates that a system that relies upon the voluntary construction of transmission funded by congestion rights like CRRs cannot

clearing price of about \$5/kw-month that could potentially be achieved once constraints have been mitigated.

¹³ This statement is based on net transmission additions from FERC Form 1 data submitted by the PJM utilities and peak demand from PJM Annual Reports for the years 1999-2001.

¹⁴ *Old Dominion Electric Coop. v. PJM Interconnection L.L.C., et al.*, 92 FERC ¶ 61,278 (2000).

¹⁵ *See, e.g., PJM Interconnection L.L.C.*, 100 FERC ¶ 61,008 (2002).

support the construction of needed transmission upgrades, and further shows that if a merchant investment framework had been relied upon to support the capital and maintenance costs of PJM's existing transmission infrastructure, congestion revenues would now cover less than 20% of those costs.¹⁶ This conclusion is echoed by PJM's own Market Monitoring Unit in its most recent State of the Market Report: "The significant increases in congestion suggest the importance of PJM implementing FERC's [July 12, 2001] order to develop an approach to identify areas where investments in transmission expansion would relieve congestion that may enhance generator market power and are needed to support competition."¹⁷

Lastly, the Commission itself has recognized that PJM must have a regional planning process that addresses economic needs and therefore has ordered that, as a condition for granting PJM status as a Regional Transmission Organization ("RTO"), "PJM's regional transmission plan must provide authority for PJM to require upgrades both to ensure system reliability and to support competition."¹⁸

The lessons learned in New York and PJM will apply to any region that implements SMD in the future. Both of these regions have had LMP for a significant period of time, but due in part to the lack of a regulatory backstop obligation on the part of transmission owners to construct economic upgrades, transmission constraints persist and undermine competitive wholesale markets. For these reasons, the final SMD rule

¹⁶ Joskow Comments at 69-71.

¹⁷ PJM Interconnection State of the Market Report 2001 at p. 118 (June 2002). This report is posted on PJM's web site at: http://www.pjm.com/market_monitoring/reports.html. Indeed, while PJM has claimed commitments for \$725 million in transmission investments (PJM Press Release, November 6, 2002), on closer review, only four out of nearly 40 transmission projects are actual "network reinforcements" that could have an impact on congestion, with the rest being largely generation interconnections. Of these four, only one involves truly new facilities. See January 10, 2003, Comments of the Transmission Access Policy Study Group at 19, n.21.

¹⁸ *PJM Interconnection L.L.C., et al.*, 101 FERC ¶ 61, 345 at P 24 (2002).

should retain the requirements that the regional transmission planning process address both reliability and economic needs, and that transmission owners should continue to be obligated to construct transmission facilities to meet regional needs identified in the planning process, with the ability to recover their costs of doing so.

2. The Commission’s Chairman Has Correctly Concluded That an RFP Process Would Delay the Construction of Needed Transmission and Should Not be Included in the Final SMD Rule.

National Grid strongly supports Chairman Wood’s recent determination that a competitive solicitation or RFP for transmission would delay the construction of needed transmission and should not be included in the final SMD rule.¹⁹ Indeed as National Grid and many other commenters have explained, requiring the ITP to undertake a formal RFP process will not only stall the construction of needed upgrades, but will also likely lead to under-investment in transmission,²⁰ perpetuate geographically limited markets by inappropriately treating transmission upgrades and generation projects as substitutes,²¹ require the ITP to perform a “least cost planning” function that is inconsistent with a market-driven system,²² and permit the ITP to reject regulated solutions in favor of market solutions that lead to least tariff cost but not least total cost to customers.²³ In

¹⁹ See the January 13, 2003, Commission News Release, *Chairman Wood Outlines FERC Plans for 2003, SMD White Paper Planned* (“A provision in the SMD proposed rule suggested that all new transmission construction follow from a competitive procurement process. Chairman Wood observed that this provision could slow down needed transmission investment in the near term, and therefore should not be included in the Commission’s final rule”).

²⁰ January 15, 2003, Comments of the American Electric Power System at 29.

²¹ January 10 National Grid Comments at 13.

²² January 10, 2003, Comments of the New York ISO at 8.

²³ Least cost planning wrongly presumes that generation, transmission and demand response are substitutes so that each dollar spent on any one of these measures produces the same total value to customers when one considers all delivery and supply charges. In fact, transmission does not compete with, but complements, generation by broadening power markets. That a relatively small amount of transmission spending can leverage large reductions in supply costs to customers is clearly missed by integrated resource planning and is a fundamental flaw of that model.

short, the proposed RFP requirement would undercut the objectives of the regional planning process and SMD in many ways.

In addition, one party appears see the RFP concept as an opportunity to obtain public and private subsidies of various kinds for merchant projects. Specifically, TransEnergie U.S. Ltd. has submitted comments urging the Commission to require an RFP process under which merchant developers can compete for the right to receive subsidies through regulated transmission rates to construct projects on the rights-of-way and other property of existing utilities.²⁴ Under TransEnergie's proposal, whenever the ITP determines that market projects are not meeting a specified ITP-identified transmission need, all transmission owners and merchant transmission providers would be required to submit bids in response to a mandatory RFP addressing this need. Furthermore, competing transmission owners would have access to each other's rights-of-way on "comparable terms" for purposes of developing ITP-planned upgrades.²⁵

National Grid and many other public utilities are prepared to assume an obligation to construct transmission upgrades on their own rights-of-way in order to satisfy the objectives of the Commission's SMD initiative.²⁶ Nonetheless, there is nothing in the Federal Power Act to suggest that the Commission has any authority to intrude upon the property rights of transmission owners by requiring them to make their rights-of-way available to third parties as part of a competitive solicitation, except on a voluntary basis.

²⁴ While TransEnergie never explicitly asks for subsidies in its Comments, there appears to be no other function for the kind of RFP process it proposes for all the reasons explained in National Grid's January 10, 2003, Comments. January 10 National Grid Comments at 21-23. That is, in the absence of the opportunity to obtain such subsidies, a merchant developer would either have its project supported by the market, or it would not build it.

²⁵ January 10, 2003, Comments of TransEnergie U.S. Ltd. at 13-15, 17.

²⁶ National Grid also acknowledges an obligation to interconnect with merchant and other generators under applicable standards on the condition that these entities show that such interconnection will have no adverse impact on system reliability or transfer capability, and subject to cost recovery provisions.

Nothing short of Congressional legislation could grant the Commission authority to compel owners of regulated transmission facilities to make their rights-of-way and other property rights available to third parties; furthermore, even if such legislation were enacted, any such compulsion could constitute a ‘taking’ of the owners’ property subject to the protections of the Fifth Amendment.²⁷

Moreover, under the TransEnergie proposal, merchant developers would retain ownership of upgrades they made to the facilities of the incumbent transmission owner. Such an arrangement would create a patchwork quilt of ownership on the transmission network, and would raise fundamental questions as to the operation and maintenance of such facilities. This is precisely the wrong direction for the industry, as such fine-scale partition of transmission facilities between different owners would likely further impede the development of an adequate, efficient platform to support the Commission’s vision for competitive power markets. Furthermore, TransEnergie suggests no remedies for the tremendous complexities of ratemaking where property of several different utilities is intermingled on the same right of way or in the same transmission facilities.

TransEnergie’s proposal would also substantially increase the many delays already associated with a formal RFP process, including the time required to consider alternative bids, solicit information, answer questions, review proposals, select “winners,” address appeals, *etc.* Moreover, by requiring all regional transmission owners

²⁷ The Supreme Court has recognized that a physical invasion of a person's property, no matter how small, is the clearest form of a compensable taking. *See Loretto v. Teleprompter Manhattan CATV Corp.*, 458 U.S. 419, 436 (1982) ("[A]n owner suffers a special kind of injury when a stranger directly invades and occupies the owner's property. . . . [P]roperty law has long protected an owner's expectation that he will be relatively undisturbed at least in the possession of his property."); *see also Dolan v. City of Tigard*, 512 U.S. 374, 393-94 (1994) (finding that a city's need for flood control could have been satisfied with a private greenway, in which the property owner could control access; requirement of a public greenway was unconstitutional because it bore no reasonable relationship to the need).

to compete with one another for projects that would normally not require such “competition,” TransEnergie’s proposal would invite endless disputes and legal challenges. Thus, TransEnergie’s proposal exacerbates all the problems that led to Chairman Wood to conclude that an RFP process is inimical to the objective of ensuring the timely completion of needed transmission upgrades.

Just as importantly, however, if TransEnergie’s proposal constitutes an attempt to obtain regulated subsidies for proposed merchant projects that the market has already rejected, and an effort to compel customers to pay for these subsidies, it should be soundly rejected. Under TransEnergie’s proposal, the ITP would only issue a formal RFP when the market has already rejected a proposed merchant project. It appears that TransEnergie may intend that, if selected in the RFP process it has proposed, the merchant transmission developer would recover on a regulated basis the costs of such projects in addition to whatever higher returns the merchant developer may earn on those merchant projects that the market *has* accepted.

Such an approach, however, would be entirely inconsistent with the Commission’s finding that developers of merchant projects must be “willing to assume any market or regulatory risk” associated with their projects.²⁸ As the Commission found in approving the Cross-Sound Cable, a fundamental tenet of merchant transmission is that “[the merchant transmission provider] has no captive customers and assumes full financial risk for the project.”²⁹ Allowing a developer of merchant transmission or

²⁸ NOPR at P 347. In the same vein, the Staff Working Paper on Standardized Transmission Service and Wholesale Electric Market Design issued in this docket on March 15, 2002 states (at 7) that “merchant transmission capacity would be built without regulatory assurance of cost recovery.”

²⁹ *TransEnergie U.S., Ltd.*, 91 FERC ¶ 61,230 at 61,839; *see also TransEnergie U.S. Ltd.*, 98 FERC ¶ 61,144 at 61,456 (the first criterion of a merchant transmission project is that “the transmission facility should assume full market risk”).

generation projects to recover costs on both a market and cost-of-service basis, which, as discussed above, appears to be implicit in TransEnergie's proposal, would allow such developers to enjoy the additional profits when the market places a high price on a scarce resource while ensuring that the developer will receive the guaranteed cost recovery of traditional regulated rates when the market will not afford higher prices. Such a hybrid cost-recovery approach would only result in higher prices to energy consumers, even without taking into account the subsidy provided to merchant developers through the free use of the property of others.

For all the reasons cited by Chairman Wood and numerous commenters, the Commission should eliminate the RFP requirement from the final SMD rule. The Commission should also reject TransEnergie's proposal for a greatly expanded RFP process that violates the legal rights of existing facility owners and that is designed to subsidize merchant developers while raising costs and reducing efficiency.

3. Merchant Transmission Will Not Meet the Majority of Transmission Needs.

The request for subsidies implicit in TransEnergie's comments is instructive in that it reinforces a conclusion that many commenters have already reached based on experience throughout the world: that merchant transmission projects are unlikely to provide the required level of capital investment or achieve the level of system expansion needed to ensure a robust transmission infrastructure that can support the kind of geographically broad competitive energy markets envisioned under SMD. National Grid's January 10 Comments explain why merchant transmission opportunities are likely to be limited to controllable market-to-market facilities.³⁰ These include the questionable

³⁰ January 10 National Grid Comments at 46-47.

and volatile nature of CRRs as a funding mechanism for merchant transmission on a free-flowing integrated network with loop flow potential, and the difficulty of assigning physical priority rights within a broad market region.³¹

As noted above, the Comments submitted by Professor Joskow include an extensive analysis of an approach to regional transmission planning that relies primarily upon merchant transmission to meet future investment needs. He concludes that such an approach fails to reflect many important economic and physical attributes of transmission investment, and is inconsistent with sound economic theory.³²

The Commission should also take particular note of the comments of TransGrid on experience with the merchant transmission model in Australia. Specifically, TransGrid explains that the Australian experience with merchant transmission has been highly problematic: “The ‘take home message’ is that regulators cannot expect merchant investment to deliver appropriate levels of transmission investment when and where it is needed most.”³³

Finally, we would note that many other difficult questions regarding merchant transmission have been raised in these and other proceedings. These include:

- Should merchant developers have an obligation to expand their transmission facilities analogous to that of regulated utilities?³⁴ How does the Commission plan to resolve the real-world issues raised by TransGrid based on the Australian experience with merchant transmission regarding (a) the amount of investment merchant transmission can be expected to attract; (b) the impact that will have on investment in regulated transmission; and (c) other

³¹ *Id.*

³² Joskow Comments at 51.

³³ January 1, 2003, Comments of TransGrid (“TransGrid Comments”) at 9. The TransGrid Comments explain in detail why, although merchant transmission can provide value in certain niche functions, Australia’s attempt to rely on merchant transmission has resulted in legal controversy and considerable delay and disruption to investment in efficient new transmission capacity.

³⁴ See the “Notice Requesting Comments on Merchant Transmission Providers’ Obligation to Expand” issued in this proceeding on November 26, 2002; January 10 National Grid Comments at 42-49.

operational and planning concerns about the coexistence of merchant transmission and regulated transmission within the same transmission grid?³⁵

- How should merchant transmission projects be folded into the regional planning process and/or the generator interconnection queue?³⁶
- What type of “transmission rights” (physical or financial) does the merchant intend to sell at negotiated rates? If they are physical rights, such as those over a controllable HVDC line, can they be integrated with minimal disruption into a financially based market design such as the one contemplated under SMD?³⁷
- What regulatory precautions are needed to ensure that merchant transmission providers follow through on their commitment to assume all market risks for their projects and do not later attempt (a) to shift such risks onto customers of regulated transmission; (b) to exchange their merchant status for a regulated utility status; (c) to block economically beneficial transmission upgrade projects that may tend to undermine the value of the transmission rights sold by the merchant provider; or (d) assert market power?³⁸
- What responsibility should merchant developers bear for the cost of upgrades to the existing transmission grid that are necessary to ensure the safe and reliable interconnection of proposed merchant transmission lines?³⁹

Because both theoretical analysis and real-world experience demonstrate that merchant transmission investment will fall far short of achieving the objective of a robust transmission grid that supports competitive markets, the Commission’s final SMD rule must provide for a strong regional planning process that supports and encourages transmission infrastructure investment on a regulated basis and avoids subsidies for

³⁵ See TransGrid Comments at pp. 9-29.

³⁶ See “Notice of Possible Discussion Items For January 21, 2003 Queuing Technical Conference” issued in this proceeding on December 17, 2002, at 5 (question 3.D); February 4, 2003, Comments of National Grid USA at 3-6; January 10 National Grid Comments at 6-26.

³⁷ See January 10 National Grid Comments at 46-47, 84-86.

³⁸ See January 10 National Grid at 8-12, 18-24, 21-23, 42-47; *see also* November 15, 2002, Comments of National Grid at 18-24 (“November 15 National Grid Comments”).

³⁹ See January 10 National Grid Comments at 26-42.

market supported products such as merchant transmission. This will require explicit rules prohibiting conversion of merchant transmission projects to regulated status.⁴⁰

4. An Effective Planning Process Will Rely Primarily on Incumbent Transmission Owners To Build Needed Transmission Upgrades.

National Grid supports the NOPR's proposal for a regional planning process that provides market information sufficient to allow developers to timely design and propose merchant projects to satisfy regional needs through voluntary market-based projects.⁴¹ Because merchant transmission will be a niche product satisfying only a narrow range of transmission needs, the Commission should ensure that the planning process required by the final SMD rule does not impede the ability of incumbent regulated transmission owners to address the nation's transmission needs. Thus, the process by which market projects are incorporated into the regional planning process must have proper safeguards that prevent the use of this process as a means to delay or discourage needed upgrades. These safeguards should include imposition of milestones that must be satisfied by any proposed merchant project that comes forward to address ITP-identified or other needs, like the milestones imposed as part of the queuing process as set forth in the Commission's Interconnection NOPR.⁴² When such milestones are not met, the Commission should view this as a signal that a transmission project built by the incumbent transmission owner under a regulated rate may be the only realistic and/or

⁴⁰ These issues are highlighted by TransEnergie's request to the Australian utility regulator that it convert its unsuccessful "Murraylink" investment from a merchant investment to regulated tariff based investment. TransGrid Comments at 12-14, 22-23.

⁴¹ Of course, as discussed previously, this should not involve a duplicative and counter-productive formal RFP issued by the ITP.

⁴² See *Standardization of Generator Interconnection Agreements and Procedures*, FERC Stats. & Regs., Proposed Regs. ¶ 32,560 (2002).

financially viable option for the needed upgrade. Such a process will guard against unproductive delays in constructing such upgrades.

The Commission should take note of the many comments explaining why an effective planning process must rely predominantly on incumbent transmission owners to address regional needs. As noted above, Professor Joskow explains that reliance on regulated transmission networks is the one “internationally proven” way to stimulate transmission investment.⁴³ Similarly, EEI has explained why incumbent transmission owners and ITCs “must be the builders of first resort within their footprints.”⁴⁴

Many regional transmission needs may best be addressed by actions that only the incumbent transmission owner can take – including maintenance, replacement, or upgrading of existing lines and facilities, installation of additional lines or other transmission facilities on existing rights-of-way, or exercise of eminent domain authority that may only be available to the transmission owner under state law.⁴⁵ An effective planning process must include an obligation for incumbent transmission owners to construct all needed upgrades on a regulated basis to the extent that a merchant developer has not committed to construct the upgrade (at its own risk) within the timelines of an open solicitation, or has failed to meet prescribed milestones for the construction of a proposed merchant project.⁴⁶

⁴³ Joskow Comments at 10, 56.

⁴⁴ January 27, 2003, Comments of Edison Electric Institute at Ex-2.

⁴⁵ As discussed above, TransEnergie proposes that all transmission owners and merchant transmission developers should have access to existing rights-of-way as part of an RFP process. January 10, 2003, Comments of TransEnergie U.S. Ltd. at 17. As explained above, such an approach is inconsistent with the property rights of incumbent transmission owners and would greatly exacerbate the delays and controversies associated with such an RFP process.

⁴⁶ This obligation should be conditioned only upon the ability of such transmission owner to obtain the necessary local, state and federal regulatory approvals and to be provided a reasonable opportunity for recovery of the costs of such transmission upgrades. *Cf.* January 10, 2003, Additional Comments of the New York ISO at p. 9 (“the NYISO supports the NOPR’s proposal that TOs continue to be the transmission

5. The Final SMD Rule Should Not Include the Flawed Participant Funding Proposal.

a. Ambiguity of the Proposal.

As noted in National Grid’s January 10 Comments,⁴⁷ the NOPR’s “participant funding” proposal for construction and pricing of transmission upgrades is ambiguous. However, under any of its possible meanings, this proposal would have deleterious effects. If “participant funding” is intended to denote reliance on voluntary funding of transmission projects, it should be clear that this type of mechanism is unlikely to produce the many millions of dollars in transmission investment needed to support competitive markets: customers are unlikely to often volunteer for such costs, and many may prefer to take their chances at becoming free riders in the event that the project is built without their support. On the other hand – to the extent the Commission intends “participant funding” to refer to a mechanism under which the ITP allocates the costs of a transmission project to the “participants” that it determines will benefit from the project – the Commission should recognize that the process of identifying the beneficiaries of each transmission upgrade on a case-by-case basis will be inexact, contentious, resource-intensive, and time-consuming. Customers have a natural incentive to argue that others should be identified as the beneficiaries who must pay for upgrades, and the ITP’s identification of beneficiaries will often be challenged through dispute resolution processes, and ultimately through appeals to the Commission.

b. Other Analyses Reject Across-the-Board Application of Participant Funding.

builders of last resort. It is essential, however, that the Commission and state regulators work together to ensure that TOs have the opportunity to fully recover their costs at any time that this obligation to build is triggered.”).

⁴⁷ January 10 National Grid Comments at 27-29.

Indeed, many commenters find the NOPR's proposed participant funding mechanism highly problematic.⁴⁸ Among other things, Professor Joskow notes that implementation of a participant funding model based on a negotiated case-by-case or project-by-project basis will be extremely difficult:

Relying on case-by-case resolution of participant funding obligations is likely to lead to an extended process of debate and haggling about who should pay for what and when. The ultimate result of this approach will be that transmission investment will be delayed or retarded by free riders who would prefer not to pay and by market participants who would prefer to continue to benefit from congestion.

Why will a case-by-case negotiated apportionment of cost responsibility be so difficult? There are several important reasons. The benefits created by transmission investment will typically accrue to a variety of market participants and are likely to be widely dispersed among many market participants. These beneficiaries may be distributed across multiple TOs and ITPs. Any negotiation with so many potential beneficiaries will be time consuming and involve significant transactions costs. Moreover, it will be very difficult to identify who the relevant beneficiaries are who should be at the negotiation table. The distribution of benefits can vary widely over time as supply and demand conditions change so that identifying who benefits and by how much is very difficult. Since transmission investments are long-lived, identifying the distribution of beneficiaries and quantifying the benefits over the life of a particular project is especially difficult at the project development stage. In addition, many transmission investments provide both economic and reliability benefits so that these investments are characterized by joint costs and the associated challenges of cost allocation.⁴⁹

Such difficulties should be anticipated if the ITP is required to administer a pricing mechanism that involves a case-by-case determination of the beneficiaries of all or most new transmission projects.

⁴⁸ See e.g. January 10, 2003 Comments of the American Public Power Association on Reserved Issues, at 11-12; January 10, 2003 Comments of the Transmission Access Policy Study Group, at 18-27.

⁴⁹ Joskow Comments at 61-63 (footnotes omitted).

c. Experience in New England.

Experience in New England has demonstrated the inefficiency and controversy associated with a case-by-case pricing methodology. Every recent major upgrade in New England has been litigated at the Commission, starting with NEMA/Boston's \$35M upgrades, and followed by the Southwestern Connecticut upgrades, which will cost approximately \$600 million. National Grid anticipates that, absent clear *ex ante* allocation rules, the Commission will soon face similar disputes regarding the allocation of the cost of (1) upgrades for Vermont, (2) upgrades to free up locked-in generation in Maine and Southeastern Massachusetts /Northern Rhode Island, and (3) additional upgrades for NEMA/Boston.⁵⁰

d. Some Commenters Misunderstand the NOPR Proposal.

Seizing upon one or another of the possible interpretations of the NOPR's "participant funding" proposal, many entities have submitted comments that superficially appear to support it. However, upon closer scrutiny, these comments invariably fail to confront the fact that "participant funding" is subject to multiple interpretations, and also fail to address the problems inherent in applying participant funding (under any definition) to all or most transmission upgrades.

⁵⁰ National Grid notes that representatives of every state in New England have sought rehearing of the Commission's recent findings concerning the allocation of costs of transmission upgrades constructed in Southwest Connecticut over the next five years. *New England Power Pool et al.*, 101 FERC ¶ 61,344 at P 36 (2002). Many of these rehearing requests express concern with the characterization that the methodology for allocating such Southwest Connecticut upgrade costs is an "exception" to the generally applicable new transmission cost allocation methodology to be developed for New England. *See e.g.*, the January 21, 2003, Motion for Clarification or in the Alternative Request for Rehearing of the Massachusetts Department of Telecommunications and Energy in Docket No. ER02-2330; and the January 21, 2003, Motion for Clarification or Request for Rehearing of Maine Public Utilities Commission, Maine Public Advocate, Rhode Island Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, and the Attorney General of the State of Rhode Island in Docket No. ER02-2330. The level of controversy now facing the Commission on that issue is likely to become commonplace if the Commission implements a pricing approach which requires a case-by-case determination of which participants benefit from a given transmission upgrade.

Some commenters appear to support participant funding simply because they believe that it will allow them to avoid paying a share of anticipated regional transmission upgrades needed in their areas. Others appear to construe the ambiguities in the NOPR proposal in ways contrary to the NOPR’s intent. For example, PJM apparently equates “participant funding” with the “but for” pricing of generation interconnection-related system upgrades that the Commission has approved for PJM and other regions.⁵¹ PJM expresses strong support for the “participant funding” proposal by reference to its consistency with PJM’s experience with mandatory “but for” pricing for generation interconnection related upgrades; however, this expression of support does not hold up under closer scrutiny. While it is true that the NOPR references generation interconnection as one circumstance where its proposed participant funding approach would be applied, the Commission has also indicated that generators should not participant-fund network upgrade costs.⁵² In fact, the NOPR suggests that the costs of *all or most* transmission upgrades (and not merely those designed to facilitate the interconnection of a generator or other entity) should be allocated to those who benefit from the proposal.⁵³ In contrast to the “but for” pricing model supported by PJM, where interconnection costs are assigned directly to the interconnecting party while most other costs are “rolled in” to regional or zonal rates, the NOPR’s “participant funding” proposal

⁵¹ See January 10, 2003, Additional Comments of PJM, Interconnection, LLC at p. 15, *citing Standardizing Generator Interconnection Agreements and Procedures*, Advance Notice of Proposed Rulemaking, FERC Stats. & Regs., ¶ 35,540 at 35,820 (2001).

⁵² NOPR at P 193; *see also Standardization of Generator Interconnection Agreements and Procedures*, FERC Stats. & Regs., Proposed Regs. ¶ 32,560; *Wrightsville Power Facility, L.L.C. v. Entergy Arkansas, Inc., et al.*, Order On Complaint, Rehearing, and Compliance Filings, 102 FERC ¶ 61,212 (February 26, 2003)

⁵³ NOPR at P 197.

is presented as a departure from this “traditional means of expansion pricing.”⁵⁴ The NOPR appears quite clear that this new approach would require identification of the parties who are the economic beneficiaries of higher voltage upgrades – even where those beneficiaries are completely outside a single transmission owner's system, or the state in which the transmission upgrade is constructed.⁵⁵ This is quite different from the “but-for” funding approach supported by PJM. Consequently, PJM’s comments do not actually provide any support to the NOPR’s “participant funding” approach.

Finally, some commenters have suggested that that voluntary participant funding is warranted because an *ex ante* transmission pricing policy with rolled-in rates for some transmission upgrades is somehow inconsistent with LMP.⁵⁶ This claim is belied by an economic analysis performed by David B. Patton, the Independent Market Advisor for the New York ISO and ISO New England, which is provided as Attachment A to these Reply Comments. Dr. Patton concludes that “[a]llocating these costs more broadly is not inconsistent with LMP since it will occur in cases where the LMP signals are insufficient to bring about economically efficient or necessary new investment. Further, such an allocation will do nothing to distort or otherwise hinder the operation of the LMP energy and ancillary services markets.”⁵⁷ Consequently, the Commission should disregard

⁵⁴ *Id.* at PP 193, 196.

⁵⁵ *Id.* at PP 195-96.

⁵⁶ *See, e.g.*, January 10, 2003, Comments of Entergy Services, Inc. at 3-4.

⁵⁷ Allocating the Costs of Transmission Investment Under Locational Marginal Pricing, David B. Patton, Ph. D., January 17, 2003 at 6 (“For larger investments that are more “lumpy” and exhibit substantial economies of scale, the value of the transmission rights associated with the investment are likely to not compensate the participant for bearing the costs of the investment. Therefore, a broader allocation of the investment costs can be justified in this case. To the extent that using a cost allocation rule to assign transmission costs is preferable to assigning costs on a case-by-case basis, this principle would support the use of a rule that would allocate the costs of high voltage projects more broadly than low voltage investments.”).

comments based on the notion that regional allocation of transmission costs is inconsistent with LMP.

e. National Grid's Proposed Approach.

In addition to its reservations regarding the voluntary nature of “participant funding,” National Grid objects to the application of the “participant funding” approach for all or most transmission upgrades because the case-by-case cost allocation determinations required by that methodology would delay needed infrastructure improvements. It should be emphasized that National Grid’s objections do not take issue with the principle that the “beneficiaries should pay” for the costs of transmission upgrades. As explained in Professor Joskow’s comments, the NOPR’s general concept of assigning payment obligations to those who benefit from a transmission investment makes very good sense, but in practice a set of reasonable *ex ante* cost responsibility criteria must be used to implement this concept.⁵⁸

This is the approach proposed by National Grid in its January 10 Comments. In those comments, National Grid outlined a mandatory default pricing mechanism that effectively distinguishes between local and regional benefits, while avoiding the requirement to identify the particular beneficiaries of each and every proposed upgrade on a case-by-case basis.⁵⁹

It should be noted that this approach is consistent with the recent remarks by the Commission’s Chairman supporting a transmission funding mechanism that allocates regionally transmission upgrades for native load reliability and economic efficiency, and directly assigns only costs of transmission upgrades requested by parties above and

⁵⁸ Joskow Comments at 60-61.

⁵⁹ January 10 National Grid Comments at 32-39.

beyond this level.⁶⁰ In addition, the Court of Appeals for the District of Columbia Circuit recently upheld the Commission's authority to assign costs according to a default pricing methodology that allocates such costs regionally.⁶¹

The Commission's final SMD rule should adopt a default pricing methodology based on the principles set forth in National Grid's January 10 Comments in order to avoid the many pitfalls of "participant funding" approaches based on either voluntary negotiations among participants or case-by-case administrative determinations by the ITP.

6. The Commission Should Preserve Its Policy Against Unnecessary Abrogation of Contracts.

Many commenters have presented cogent arguments for the grandfathering of transmission agreements, and for the Commission to honor its policies against abrogation of contracts.⁶² Similarly, National Grid strongly believes that the Commission's commitment to grandfathering preexisting agreements (many of which, in the regions served by National Grid, pre-date the current ISO/RTO paradigm) is both good policy and critical to the smooth and rapid implementation of SMD.

The principle that the Commission should not abrogate existing transmission contracts is particularly important as applied to project-financed transmission facilities in which customers contracted to receive long-term usage rights in exchange for their commitment to support the costs of a project. Such transmission facilities include

⁶⁰ These comments were made at the Commission's February 20, 2003, meeting, a transcript of which will be posted on the Commission's web site at: <http://www.ferc.gov/calendar/commissionmeetings/transcripts.htm>.

⁶¹ See *Entergy Services Co. v. Federal Energy Regulatory Commission*, Docket No. 01-1487 (D.C. Cir. Feb. 18, 2003).

⁶² See, e.g., November 15, 2002, Comments of Edison Electric Institute at 38-39; November 27, 2002, Comments of the Montana, Office of the Governor, *et al.*, at 7; and January 10, 2003 Comments of DTE Energy Co. at 27-28.

merchant transmission, like the Cross-Sound Cable project constructed by TransEnergie U.S. Ltd. The Cross-Sound Cable project is funded through bilateral agreements to provide physical transmission rights in exchange for the agreement of certain customers to fund the project.⁶³ TransEnergie’s proposed Harbor Cable project would also be funded through such arrangements.⁶⁴ The Commission has not rejected the funding arrangements for such projects as creating rate pancaking, but has instead recognized that private funding of such controllable HVDC transmission projects between two markets (e.g., external ties between separate RTO or ITP regions) is a wholly appropriate (albeit limited) application of the “merchant transmission” model.⁶⁵

Ironically, despite all of this, H.Q. Energy Services (U.S.), Inc., an affiliate of TransEnergie, has submitted comments arguing that the existing pre-888 financial arrangements for funding the “HQ Interconnection” – a controllable HVDC transmission intertie between New England and Québec – represent a “pancaked rate” that the Commission should eliminate as part of the final SMD rule.⁶⁶ This represents a misunderstanding on the part of H.Q. Energy Services, which is contrary both to the Commission’s approval of the cable projects proposed by its affiliate TransEnergie, and

⁶³ See, e.g., *TransEnergie U.S., Ltd.*, 91 FERC ¶ 61,230 (2000).

⁶⁴ *TransEnergie U.S. Ltd.*, 98 FERC ¶ 61,144 at 61,455 (2002) (authorizing the sale of “tradable firm secondary transmission rights” that will consist of “physical transmission rights to import into, or export out of, PJM and NYISO” to fund an underground and submarine HVDC transmission cable system connecting PJM and the NYISO).

⁶⁵ It is worth stressing that permitting customers to retain contracted-for physical scheduling rights to controllable transmission interties between two separate markets, such as the HQ Interconnection, should in no way interfere with the operation of markets based on financial rights, as proposed in the SMD NOPR. While many commenters, including National Grid, have raised concerns about mixing physical and financial rights over integrated intra-market transmission facilities, such market-to-market interties are, by definition, controlled separately from the integrated AC network. Indeed, transfers can be made over such facilities only in one direction at a time, and they do not support unscheduled transfers as does the integrated AC grid. Regardless of how the rights to use such projects are characterized, their operations between two markets must be managed on a physical basis and coordinated with the ITP’s operation of the integrated AC network and bid-based dispatch of generation under the LMP model.

⁶⁶ January 10, 2003, Comments of H.Q. Energy Services (U.S.), Inc. at 3-4.

to the Commission’s policy prohibiting the abrogation of existing transmission contracts.⁶⁷ Utilities throughout New England, including subsidiaries of National Grid, committed in the 1980’s to support the costs of constructing and operating the HQ Interconnection (whose costs were not included in rolled-in transmission rates), in exchange for proportionate rights to use the project’s capacity to transfer power between Canada and New England, as customers of the developers of the intertie (the “Asset Owners”).⁶⁸ Those usage rights are embodied in contracts among the supporting utilities (the “Interconnection Rights Holders”), and the Asset Owners, which contracts formed the basis for the financing of the project. Mandating the roll-in of the HQ Interconnection costs into regional rates without the agreement of the Interconnection Rights Holders and Asset Owners would result in the abrogation of those contracts in violation of Commission policy and precedent.⁶⁹ Once users have obtained such rights in exchange for their commitment to support a transmission project, they must be permitted to retain those rights as well as the ability to resell them in bilateral transactions, in order to protect the legitimate economic expectations of their transmission customers, as well as to ensure that the fundamental prerequisites (including reasonable property and

⁶⁷ See SMD NOPR at P 373; see also *New England Power Pool and ISO New England*, 100 FERC ¶ 61,287 P 105 (2002) (finding that the Interconnection rights holders have existing contractual rights and obligations that must be properly addressed in any future disposition of the HQ Interconnection).

⁶⁸ See *New England Hydro Transmission Corp., et al.*, 39 FERC ¶ 61,288 (1987).

⁶⁹ See *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 14-15 (D.C. Cir. 2002); *PacifiCorp v. Reliant Energy Services Inc.*, 102 FERC ¶ 63,030 at P 15 (2003); *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs., Regs. Preambles ¶ 31,036 (1996) (“Order No. 888”), *order on reh’g*, Order No. 888-A, FERC Stats. & Regs., Regs. Preambles ¶ 31,048 (1997), *order on reh’g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh’g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff’d in part and remanded in part sub nom. Transmission Access Policy Study Group, et al. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff’d sub nom. New York v. FERC*, 122 S. Ct. 1012 (2002); *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs., Regs. Preambles ¶ 31,089 at 31,205 (1999), *order on reh’g*, Order No. 2000-A, FERC Stats. & Regs ¶ 31,092 (2000), *petitions for review dismissed, Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

contractual expectations) for the financing of this project, as well as similar transmission projects in the future, are not undermined.

The Interconnection Rights Holders and Asset Owners are currently engaged in negotiations concerning options for integrating the HQ Interconnection into the larger Northeast transmission system, focusing on the allocation of the rights and responsibilities associated with the existing HQ Interconnection contracts. National Grid hopes that a negotiated resolution of these issues can be submitted to the Commission in the near future. It would be inappropriate, however, for the Commission to mandate the abrogation of the existing pre-888 funding agreements for the HQ Interconnection.⁷⁰ New participant funding contracts are permitted under SMD. There is no reason for existing ones to be abrogated.

For these reasons, the Commission should reject TransEnergie's self-serving accusations of "rate pancaking." Rather it should reaffirm its policy of allowing grandfathering of preexisting transmission contracts and against abrogation of such contracts.

B. Resource Adequacy

1. Locational Capacity Requirements Threaten the Objective of Large, Competitive Electricity Markets.

As the NOPR makes clear, a robust deliverability requirement for capacity resources is a cornerstone of any SMD Resource Adequacy mechanism.⁷¹ Recognizing

⁷⁰ In addition, even assuming for the sake of argument that a failure to abrogate the HQ Interconnection contracts comprised pancaking, abrogation would still be contrary to the public interest in this case. This is because virtually all the generation on the Canadian side of this intertie is owned and controlled by a monopolist. As a result, permitting the owners and rights holders of the HQ Interconnection to charge rates as provided in their contracts is the only protection New England has against a projection of this monopoly power into the New England energy markets.

⁷¹ See, e.g., NOPR at PP 511, 514.

the importance of deliverability, National Grid and many other commenters⁷² have supported a PJM-style regional deliverability requirement for capacity resources. However, another group of commenters, while recognizing the need for deliverability, proposes that a locational capacity mechanism should be used in its stead. Thus, the New York ISO (“NYISO”) states:

The NYISO has developed locational requirements for ensuring resource adequacy in load pockets. The locational requirements address concerns raised by the Commission by requiring that a predetermined amount of resources furnishing a resource adequacy product (backed by generation or demand response) to the load pocket be physically sited in the load pocket. This is an acceptable alternative to ensure the reliability of the system from a resource adequacy point of view, *and recognizes the constraints imposed by the existing transmission infrastructure.*⁷³

Similarly, NRG argues that:

the Commission’s local and safety-net mitigation measures limit the price signals to both supply and demand resources precisely where there is the greatest need for scarcity revenues to maintain and attract resources needed to keep supply and demand in balance. . . . But without a locational requirement, ICAP markets target too few dollars *on constrained areas* to induce the needed level of capacity and other resources . . .⁷⁴

NYISO and NRG are certainly correct that locational requirements reflect “constraints imposed by the existing transmission infrastructure” and “constrained areas.” The problem with their analyses is that both assume that these constraints are permanent features of the transmission system. However, one of the central objectives of SMD is to promote transmission infrastructure investment where this is needed to *remove* such constraints.

⁷² See e.g. January 10, 2003, Comments of Louisville Gas & Electric Co., *et al* at 9; January 10, 2003 Comments of the SeTrans Sponsors at 13-16.

⁷³ January 10, 2003, Comments of the New York ISO at 16 (“NYISO Comments”) (emphasis supplied).

⁷⁴ January 10, 2003, Comments of NRG at 14 (“NRG Comments”) (emphasis supplied).

Locational requirements of the kind supported by NYISO and NRG may temporarily and partially mitigate some of the problems associated with inadequate transmission infrastructure; however, such locational requirements should not be permanently institutionalized under SMD. Such a move would merely serve to entrench the very transmission constraints giving rise to the need for locational requirements in the first place. Moreover, the geographically limited markets perpetuated by locational requirements can easily give rise to market power, as is amply demonstrated by the need for strict Market Mitigation Rules in the design of the NYISO.

As National Grid has shown in its January 10 Comments,⁷⁵ while locational capacity mechanisms can address one of the two crucial functions of a regional deliverability requirement, it cannot address both. That is, a locational requirement can ensure adequate capacity within a load pocket, but it cannot spur the construction of adequate transmission infrastructure to integrate the load pocket with the wider market. This is because incentives to build additional transmission to better serve a load pocket are rendered uneconomic if locational rules require local purchase of generation within the defined load pocket and/or prohibit the importation of external resources into the load pocket. Consequently, locational requirements necessarily create geographically limited markets in which suppliers may be able to assert market power and charge higher prices for capacity from resources within the constrained area. The Commission should not promote a market design that in the long run perpetuates reliance on market mitigation

⁷⁵ January 10 National Grid Comments at 52-60. The Commission should note that these January 10 Comments erroneously stated that the New York State Reliability Council (“NYSRC”) is responsible for establishing locational requirements in New York. National Grid hereby corrects these statements by clarifying that it is actually NYISO that has this responsibility.

rules and preserves price differences by accepting continuing locational requirements for capacity resources.

If transmission constraints are to be relieved, and load pockets integrated into the regional electricity markets in accordance with the NOPR's objectives, additional transmission must be built. National Grid's January 10 Comments propose a five-year transition mechanism during which such integration can take place in such a way that reliability is maintained while transmission infrastructure is upgraded in order to allow customers in the load pocket to take advantage of the regional markets.⁷⁶ During that period, locational capacity requirements and local reliability rules can be periodically reviewed and, as transmission network upgrades are installed, eliminated.

3. The Commission Should Permit LSEs To Satisfy Their Resource Adequacy Requirements By Means of Appropriately Structured Bilateral Contracts.

Many of the comments on the Resource Adequacy portion of the SMD NOPR can be divided into two broad categories: those that favor a mechanism putting responsibility for long-term capacity planning and procurement entirely on LSEs and penalizing them for shortfalls,⁷⁷ and those that place all of the responsibility for capacity planning and procurement on the ITP.⁷⁸ National Grid does not necessarily agree with either of these two extremes. Rather, National Grid believes that LSEs should be permitted to procure as much of their capacity requirements as they desire under qualifying bilateral contracts. While commenters propose a variety of Resource Adequacy regimes, which impose a range of procurement and penalty requirements on ITPs or LSEs under various market-

⁷⁶ NRG argues that a regional ICAP market like PJM's is inefficient. NRG Comments at 14. However, while inefficiencies that may exist in a regional market can be corrected by adjusting market rules, it will be impossible to facilitate broad regional markets if the Commission effectively institutionalizes balkanized local markets prone to generator market power.

⁷⁷ See, e.g., NYISO Comments at 17-18.

based or administratively-determined mechanisms, such mechanisms should address only *residual* capacity requirements that remain unfulfilled by the LSEs' bilateral contracts.

Such an approach will allow the maximum play of market forces in the Resource Adequacy area, as individual business decisions by LSEs and generators are used to address the bulk of regional capacity requirements.

C. Role of Independent Transmission Companies

The Commission has expressed strong support for the development of a robust independent transmission sector as part of the transition to regional transmission entities under SMD, finding that “ITCs would be instrumental in achieving the goals of Order No. 2000” and that “ITCs would be more likely to relieve congestion through transmission investment than a company that benefits from the value of generation in constrained areas.”⁷⁹ Despite this, a few commenters attempt to revive discredited arguments impugning the independence of ITCs and their appropriateness as transmission providers under SMD.⁸⁰ The short answer to these arguments is that the Commission has already evaluated and rejected them in numerous contexts. The Commission’s recently issued Proposed Pricing Policy provides financial incentives to utilities that transfer operational control of their transmission facilities to ITCs, in order “[t]o encourage . . . formation of ITCs,” which it finds “will promote competitive wholesale electric markets, reduce wholesale electric costs, and improve electric reliability.”⁸¹ The Proposed Pricing Policy also finds that “significant benefits from competition are expected to result from

⁷⁸ See January 10, 2003, Comments of the Maine Public Utilities Commission at 3-4.

⁷⁹ *Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid*, 102 FERC ¶ 61,032 at PP 5, 17 (2003) (“Proposed Pricing Policy”).

⁸⁰ See November 15, 2002, Comments of the PSEG Cos. at 20-26; November 15, 2002, Comments of TransEnergie U.S. Ltd.

⁸¹ *Proposed Pricing Policy*, at PP 1, 28.

RTOs and ITCs” and that “these benefits will be shared among end-use customers and generators, among others.”⁸² Similarly, the SMD NOPR itself reiterates that the Commission has “long recognized that the ITC business model can bring significant benefits to the industry,”⁸³ noting that this business model is “ideally suited to bring about: (1) improved asset management . . . ; (2) improved access to capital markets . . . ; (3) development of innovative services; and (4) additional independence from market participants.”⁸⁴ Several other recent Commission Orders have come to similar conclusions.⁸⁵

However, despite the Commission’s support for ITCs, they are unlikely to be formed as long as significant uncertainty remains as to the functions that they may perform. In order to eliminate this uncertainty, the Commission should confirm that – at a minimum – it remains committed to its current ITC framework, including the ITC’s authority to perform those functions authorized under the Commission’s April 2002 *TRANSLink* and *Alliance* orders.⁸⁶

Some commenters have suggested that the allocation of functions to an ITC, and the specific nature of those functions, should vary from region to region, depending on “the degree of market development and implementation of standard market design.”⁸⁷ Such comments fail to acknowledge that the Commission has already addressed this issue by directing PJM, an RTO that serves as the model for LMP-based markets and standard

⁸² *Id.* at P 21.

⁸³ *Id.* at P 16.

⁸⁴ NOPR at P 132.

⁸⁵ *See, e.g., International Transmission Co.*, 92 FERC ¶ 61,276 at 61,917 (2000); *Trans-Elect, Inc., et al.*, 98 FERC ¶ 61,142, *order on reh’g*, 98 FERC ¶ 61,368 (2002).

⁸⁶ *TRANSLink Transmission Company, LLC, et al.* 99 FERC ¶ 61,106 at 61,455 (“*TRANSLink*”), *order on reh’g*, 101 FERC ¶ 61,140 (2002); *Alliance Companies, et al.*, 99 FERC ¶ 61,105 (2002) (“*Alliance*”).

⁸⁷ *See, e.g.*, January 10, 2003, Comments of ISO New England, Inc. at 8-11.

market design, to revise its tariff to permit ITCs to operate under PJM in the same manner that the ITCs were permitted to operate under the Midwest ISO, and determining that, to the extent that the PJM tariff did not permit ITCs to operate with the same scope of authority as was permitted in the Midwest ISO and mandated by the Commission's *TRANSLink* and April, 2002 Orders, the PJM tariff was unjust and unreasonable.⁸⁸ In fact, the *TRANSLink* order itself identified the one significant function that an ITC should not undertake in an LMP-based market environment – the pricing of transmission congestion.⁸⁹ Once LMP is implemented in a given region, an ITC in that region will not have separate procedures for congestion pricing but could well have an incentive-based system for truly managing (*i.e.*, reducing) transmission congestion through efficient operation of transmission assets and investment in transmission upgrades.

When considering the allocation of functions to an ITC, the Commission should take particular note of a paper submitted by Paul Addison, a former managing director of Salomon Smith Barney's Global Power Group and managing director at Citicorp Securities Inc.⁹⁰ The paper concludes that:

The split of functions as outlined in the Midwest ISO Appendix I and built upon in the *TRANSLink* filing offers a reasonable opportunity for an ITC to manage those functions which will have the most significant impact on operating performance. At a minimum, this split of functions should be preserved in the final SMD.⁹¹

Mr. Addison also explains that, in order to be an attractive business proposition (*i.e.*, obtain outside financing), an ITC must have a high degree of certainty that its business

⁸⁸ *Alliance Companies, et al.*, 100 FERC ¶ 61,137 at P 43 (2002).

⁸⁹ The Commission noted that, with the adoption of LMP in a given region, there is "little opportunity for ITCs to segment the region with alternative congestion management systems. The LMP market needs not only to be uniform, but also operated as single market." *TRANSLink*, 99 FERC ¶ 61,106, 61,469 (2002).

model, including the split of operating functions, will obtain favorable regulatory treatment from the Commission.⁹² Thus, in order to truly promote the development of the independent transmission sector, the Commission should preserve its existing framework for ITC functionality in the final SMD rule.

⁹⁰ *The Role of an Independent Transmission Company Under FERC's Proposed Standard Market Design*, filed January 1, 2003 (the "Addison Paper").

⁹¹ Addison Paper at 4.

⁹² *Id.* at 6-7.

III. CONCLUSION

National Grid respectfully requests that the Commission accept these Reply Comments and incorporate the proposed modifications and clarifications in its forthcoming white paper and its final rule on Network Access Service and Standard Market Design.

Respectfully submitted,

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ATTACHMENT A