129 FERC ¶ 61,279
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer and Philip D. Moeller.

Northeast Utilities Service Company and NSTAR Electric Company — Docket No. EL09-20-001

ORDER DENYING REHEARING AND CLARIFICATION

(Issued December 29, 2009)

1. Indicated New England Generators (Indicated NE Generators)[1] and the New England Power Generators Association, Inc. (NEPGA) request rehearing of the Commission's May 22, 2009 order[2] approving the structure of a transaction involving a cost-based, participant-funded transmission project (Project) that includes a long-term, bilateral transmission service agreement (Transmission Service Agreement) between Northeast Utilities Service Company (Northeast) and NSTAR Electric Company (NSTAR) (collectively, Petitioners) and H.Q. Energy Services (U.S.) Inc. (HQUS). For the reasons discussed below, we deny rehearing and clarification.

I. **Background**

2. In their Petition, the Petitioners stated that the Project will provide access to over 4,000 MW of new hydro-electric generation in the Province of Québec with significant amounts of surplus hydro-electric power made available for export to the United States. In order to gain access to these hydro-electric power resources and complete the transaction structure, the Petitioners explained that three core agreements were being negotiated. The first agreement is a joint development agreement between the Petitioners and Hydro-Québec TransÉnergie (HQ TransÉnergie) for the design, planning and

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[1] Indicated New England Generators includes NextEra Energy Resources, LLC, Mirant Energy Trading, LLC, Mirant Canal, LLC, Mirant Kendall, LLC and TransCanada Power Marketing Ltd.

[2] *Northeast Utilities Service Co. and NSTAR Electric Co.*, 127 FERC ¶ 61,179 (2009) (May 22 Order).

construction of a 1,200 MW high voltage direct current (HVDC) transmission line that will connect Hydro-Québec's system into the 345 kV transmission system controlled by ISO New England, Inc. (ISO-NE) in Southern New Hampshire.

3. The second core agreement is the Transmission Service Agreement under which HQUS will acquire 1,200 MW of firm transmission rights from the Petitioners capped at a cost-based rate, including a reasonable return on the Petitioners' invested capital. Once executed, the Transmission Service Agreement will be filed with the Commission pursuant to section 205 of the Federal Power Act and will be subject to a Commission approved, cost-based rate ceiling. Further, the Petitioners stated that, because the transmission line is participant-funded by HQUS, the costs of the Project will not be included in the rates for transmission service under ISO-NE's Open Access Transmission Tariff (OATT).

4. The third core agreement is a power purchase agreement under which HQUS will sell 1,200 MW of firm power to Petitioners and other interested New England entities for a period of no less than twenty years under HQUS' market-based rate tariff, which is on file with the Commission. The Petitioners stated that HQUS will recover the cost of transmission rights it acquires under the Transmission Service Agreement through the price of power sold under the power purchase agreement, and that both agreements are related and should be considered as part of a combined energy and transmission transaction. The Petitioners and HQUS explained that the power sold under the power purchase agreement will be made broadly available to load in New England and that any potential buyers will have at least a twenty-year purchase commitment and must meet reasonable credit requirements. The Petitioners also stated that they must demonstrate to New England state regulatory authorities that the power purchase agreement represents a fair deal for New England electric customers in order for the transaction to go forward.

5. In the Petition, the Petitioners describe several significant benefits that the Project offers to New England and its customers. The Project's anticipated 1,200 MW of low-cost hydro-electric power should help reduce dependence on fossil fuels, increase fuel diversity, minimize price volatility in New England, and reduce greenhouse gas emissions associated with producing electricity by an estimated four to six million tons of CO_2 per year during the term of the transaction, which will assist in meeting regional environmental goals. The Petitioners argued that the additional power will likely reduce the Locational Marginal Price (LMP) of energy in New England at a time when electricity prices in the region are rising. Finally, the Petitioners claimed that because the Project will be participant-funded, the New England transmission system will be expanded without raising regional transmission rates under ISO-NE's OATT or creating disputes over cost allocation of the Project's transmission line.

6. In the May 22 Order, the Commission approved the structure of the transaction subject to a further independent review of the Transmission Service Agreement and the Transmission Operating Agreement (TOA), and any other jurisdictional rate schedules,

when they are submitted to the Commission. The May 22 Order explained that when those filings are made, the Commission then will evaluate whether the rates, terms and conditions included in the executed Transmission Service Agreement are just, reasonable and not unduly discriminatory or preferential.[3]

II. Rehearing Requests

7. Indicated NE Generators and NEPGA filed requests for rehearing of the May 22 Order on June 19, 2009. The Petitioners filed an answer on July 9, 2009.

III. Procedural Matters

8. Rule 713(d)(1) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d)(1) (2008), prohibits answers to a request for rehearing. Therefore, we will reject the Petitioners' answer to the requests for rehearing.

IV. Discussion

A. Order Nos. 888 and 890 Issues

1. May 22 Order

9. In the May 22 Order, the Commission found that the Petitioners' proposal does not contravene the Commission's open access requirements in Order Nos. 888[4] and 890[5] and is not anticompetitive. The Commission also found that providing for participant-funding of a transmission facility with priority rights to use that facility is fully consistent with its

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[3] May 22 Order at P 17.

[4] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats, & Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g* Order No. 888-B, 81 FERC ¶ 61,248, *order on reh'g,* Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group* v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. FERC. 535 U.S. 1 (2002) (Order No. 888).

[5] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats & Regs. ¶ 31,241, *order on reh'g,* Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g,* Order No. 890-B, 123 FERC ¶ 61,299 (2008) *order on reh'g,* Order No. 890-C, 126 FERC ¶ 61,228 (2009) (Order No. 890).

long-standing open access policies.[6] The May 22 Order also stated that the transaction between a transmission customer (here, HQUS) and Petitioners under which the customer has agreed to pay 100 percent of the costs for a system expansion in return for usage rights to the new HVDC transmission line does not constitute undue discrimination or preference, because any other potential transmission customer has the right to request transmission service expansion from a transmission owning utility (here, the Petitioners). In such a case, we explained, Order No. 888 requires the utility to make any necessary system expansions and to offer service at the higher of an incremental cost or an embedded cost rate to the requesting transmission customer. The Commission stated that the fact that the Petitioners will have turned over operational control of their existing transmission facilities to ISO-NE does not relieve the Petitioners of their obligations under Order No. 888 to expand their systems upon request for a potential transmission customer.[7]

10. Further, in the May 22 Order, the Commission accepted the Petitioners' offer to conduct an open season if ISO-NE determines that the Project should be expanded beyond 1,200 MW, notwithstanding also finding that an open season is not required because the Project is a cost-based, participant-funded transmission project. The May 22 Order noted that the Commission has imposed open season requirements when a merchant transmission project developer has proposed providing transmission access at negotiated rates as a way to prevent undue discrimination, but the Commission determined that this Project is not a merchant transmission project. The May 22 Order stated that the transmission expansion project requested by HQUS will be an HVDC line from Canada, with service provided at a cost-based rate that will require Commission approval in a subsequent section 205 rate filing. In the May 22 Order, the Commission found that any other potential developer has the same right to request transmission service necessary to interconnect new generation resources to the Petitioners' systems

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[6] May 22 Order at P 27 and n.27, *citing Entergy Services, Inc.*, 115 FERC ¶ 61,095, *order on reh'g*, 116 FERC ¶ 61,275 (2006), *order on reh'g and clarification*, 119 FERC ¶ 61,013, *order on reh'g and compliance filing*, 119 FERC ¶ 61,187 (2007), *order on reh'g and clarification*, 122 FERC ¶ 61,216 (2008); *Western Area Power Administration*, 99 FERC ¶ 61,306, *reh'g denied*, 100 FERC ¶ 61,331 (2002), *aff'd sub nom. Public Utilities Comm'n of the State of CA v. FERC*, 367 F.3d 925 (D.C. Cir. 2004) (approving a transmission project that grants exclusive transmission rights to the funders and no obligation of expansion) (Entergy); *Trans Bay Cable LLC*, 112 FERC ¶ 61,095 (2005), *order on reh'g*, 114 FERC ¶ 61,031 (2006) (awarding of rights for transmission funding of line); *Aero Energy, LLC*, 115 FERC ¶ 61,128 (2006) (initially awarded transmission rights to party who funded the line).

[7] May 22 Order at P 27 and n.28.

and that under Order No. 888, the Petitioners are obligated to undertake any necessary system expansion at the higher of incremental or embedded cost. Thus, the Commission found there was no undue discrimination or preference.[8]

2. Rehearing Request

11. On rehearing, Indicated NE Generators raise three issues with the Commission's findings. First, they assert that the Project is not participant-funded because the costs of Project will ultimately be recovered from the Petitioners' captive customers who purchase standard offer service. Indicated NE Generators speculate that if the Petitioners have no standard offer customers, the Petitioners might initiate a wires charge to recover the cost of the Project that they would be required to pay HQUS under the power purchase agreement.[9]

12. Second, Indicated NE Generators argue that the precedent cited in the May 22 Order does not support granting exclusive transmission rights to use a new transmission line to one party. They state that none of the cases cited by the Commission involves a combined energy and transmission transaction, and that there is no precedent for granting priority rights to use a new transmission line. However, Indicated NE Generators acknowledge that there is Commission precedent for awarding financial transmission rights (FTRs) for participant-funded network upgrades for transmission lines such as this Project that will be owned by traditional public utilities.[10]

13. Third, Indicated NE Generators claim that the transaction structure violates Order No. 888 principles and is unduly discriminatory and anti-competitive because it re-bundles transmission and generation impermissibly, thereby favoring HQUS hydropower over other alternatives. They claim that this arrangement denies independent suppliers a fair opportunity to serve the 1,200 MW of load that the Petitioners have "handed to" HQUS. Further, Indicated NE Generators assert there is already evidence that the Project is likely to increase electricity prices and harm customers because the sale of power from HQUS may not be competitively priced. Indicated NE Generators conclude that because the Petitioners will re-bundle energy and transmission and use their monopoly power over transmission to favor HQUS over alternative suppliers, the transaction structure

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[8] May 22 Order at P 29.

[9] Indicated NE Generators Rehearing Request at 2, 8, and n.9.

[10] *Id.* at 12 - 13. *See* May 22 Order at P 27 and n.27 for cases cited.

imposes excessive costs on the Petitioners' captive ratepayers if alternative suppliers are less expensive. This violates Order No. 888, according to the Indicated NE Generators.[11]

14. NEPGA asserts that the Commission erred in concluding that, because the Project and transmission service provided will be cost-based, it was not unduly discriminatory for the Petitioners to refuse to conduct an open season. NEPGA states that the May 22 Order is inconsistent with the Commission's longstanding policies regarding new gas transportation projects. NEGPA asserts that the Commission has long held that all new interstate natural gas pipeline projects should be preceded by an open season process as a way of guarding against undue discrimination and preference.[12] NEPGA argues that this precedent applies to the instant case and urges that the Commission require an open season to be held. According to NEPGA, Petitioners' claim that the transmission line will be cost-based is insufficient protection against undue discrimination and preference. NEPGA maintains that the May 22 Order erred in concluding that there is no undue discrimination simply because the Project will have negotiated rates and will be participant-funded. NEPGA concludes that this is not reasoned decision making.

15. NEPGA states that the Commission erred in failing to consider the market effects of approving a transactional structure that provides the Petitioners or their affiliates with the option of delivering power beyond the term of the power purchase agreement. They also claim that "as stated, HQUS will have the rights, but not the obligation, to deliver power after the proposed twenty-year term of the power purchase agreement based upon their own arbitrary amortization of the cost of the line."[13] NEPGA argues that there is a fifteen-year time period when ratepayers are captive to out-of-market resources that can exercise market power and limit the development of new resources. NEPGA states that this paradigm "ultimately creates a cross-subsidization of market risk" to the Petitioners' captive customers and allows the Petitioners to chill the development of competitive resources within the New England market that would benefit their customers. They assert that this construct conflicts with the Commission's open-access and non-discrimination requirements because it shifts costs and risks to captive rate payers. NEPGA argues that this represents a reversal of federal and state energy policies that encourage the development of competitive energy markets.[14]

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[11] *Id.* at 14 - 17.

[12] NEPGA Rehearing Request at 4, *citing* Order No. 2005, *Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects,* FERC Stats & Regs. ¶ 31,174, at P. 9 (2005).

[13] *Id.* at 5.

[14] *Id.* at 5 - 6.

3. <u>Commission Determination</u>

16. We deny rehearing. We have consistently found that a public utility's customers in a retail choice state who choose to buy power from the local utility under its provider-of-last-resort obligations, i.e., standard offer service customers, are not captive customers.[15] In addition, we reject any argument regarding the impact of a hypothetical stranded cost "wire charge" on retail customers as speculative and premature. The relevant state commissions will have an opportunity to review the market-based power purchase agreement when they are filed and will assess their impact on their respective retail customers. Further, HQUS must file information with this Commission regarding the market-based sales that occur under the power purchase agreement, which the Commission will review under its quarterly reporting filing requirements.

17. The Commission also rejects Indicated NE Generators' claim that the precedents cited in the May 22 Order do not apply to the instant Project. While the Commission addressed a variety of different situations in these orders regarding the provision of needed transmission in disparate regions, they all evidence the Commission's flexibility in reviewing transmission projects under the just and reasonable standard and awarding transmission rights in new or upgraded transmission projects to those entities that funded the projects. Therefore, despite factual differences, these orders support the Commission's decision to approve this participant-funded Project. For example, in *Western Area Power Administration*,[16] the Commission approved a letter agreement granting transmission system rights based on the contribution made by each participant in funding the project. In *Trans Bay Cable*,[17] the Commission approved the basic structure of a project and the related Operating Memorandum, which included awarding the transmission rights to Trans Bay for funding the project. In the latter order, as we do here, the Commission noted that many of the specific rate issues would be addressed in later rate applications. In *Entergy*,[18] among other things, the Commission approved

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[15] *FirstEnergy Solutions Corp. et al.*, 125 FERC ¶ 61,356, at P 27 (2008); *Dayton Power and Light Co.*, 123 FERC ¶ 61,231, at P 21 (2008); *Commonwealth Edison Co.*, 122 FERC ¶ 61,200, at n.10 (2008); *Duquesne Light Holdings, Inc.*, 117 FERC ¶ 61,326, at P 38 (2006).

[16] *Western Area Power Administration*, 99 FERC ¶ 61,306, *reh'g denied*, 100 FERC ¶ 61,331 (2002), *aff'd sub nom Public Utilities Comm'n of the State of CA v. FERC*, 367 F.3d 925 (D.C. Cir. 2004).

[17] *Supra* Note 4.

[18] *Id.*

Entergy's proposal to award firm transmission rights to those who funded the transmission upgrades.

18. In each of those projects, as here, the Commission approved the structure of the project and noted that, as each project progressed, additional Federal Power Act section 205 filings would be required and that these rate applications would provide the Commission with additional opportunities to review the specific rates, terms and conditions to ensure that they remained just and reasonable.

19. We also reject any arguments that the proposed transaction fails to comply with the Commission's unbundling requirements. Order No. 888 requires that the wholesale services and the prices for wholesale generation, transmission and ancillary services be separately stated. The proposed transaction structure complies with Order No. 888's unbundling requirements because both the transmission and generation services will be provided for under separate agreements and the rates will be separately stated. Thus, there is no impermissible rebundling of services or rates.

20. The Commission also rejects NEPGA's assertion that the Commission erred by not requiring an open season based upon its finding that the Project and transmission service will be cost-based. The Commission in its May 22 Order noted the precedent that requires that merchant transmission projects offering transmission capacity at market-based or negotiated rates conduct an open season as a way to prevent undue discrimination.[19] However, the Commission also found that the instant Project is not merchant in nature and therefore this precedent would not apply. Rather, the Commission found that there is no undue discrimination because, under Order No. 888, the Petitioners have the obligation to undertake any necessary system expansion at the higher of incremental or embedded costs. The Commission also rejects as misplaced NEPGA's claim that the May 22 Order is inconsistent with the Commission's open season policies for new natural gas transmission projects, because the Project is not a merchant transmission project and thus does not require an open season, as was required in *Chinook*. Moreover, NEPGA's reliance on Order No. 2005, *Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects* is misplaced as those regulations simply do not apply to the instant cost-based participant-funded project. Lastly, even though the May 22 Order did not require an open season, instead relying on the Petitioners' expansion obligations under Order No. 888, the Petitioners have committed to providing the details of any potential open season for

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[19] May 22 Order at P 41 and P 42, *citing Chinook Power Transmission, LLC*, 126 FERC ¶ 61,134 (2009).

capacity exceeding 1,200 MW in the Transmission Service Agreement that must be filed and approved by the Commission in a subsequent section 205 filing.[20]

21. The Commission dismisses as speculative and hypothetical Indicated NE Generators' arguments regarding the Project's impact on market prices and unbundling. First, the price information submitted by Indicated NE Generators on rehearing is untimely, as we generally do not permit the filing of such data at the rehearing stage.[21] Second, Indicated NE Generators' argument that the Project is likely to increase electricity prices and harm customers because the sale of power from HQUS will not be competitively priced (because of the supposedly re-bundled arrangement) [22] contradicts the Indicated NE Generators' simultaneous claim that the Petitioners' potentially large acquisition of power from HQUS under the power purchase agreement "can artificially suppress competitive prices" in the New England markets.[23] Not only are these claims internally inconsistent and irreconcilable, but each alone is mere speculation unsupported by any analysis or evidence.

22. The Commission dismisses as premature NEPGA's concern about the market effects of approving a transactional structure that provides the Petitioners or their affiliates with the option of delivering power beyond the term of the power purchase agreement. In the May 22 Order, the Commission stated that it previously approved cost-based transmission projects where the transmission rights were not tied to the length of any agreement. The Commission also stated that it would fully resolve the question of the appropriate length of the transmission rights in the context of the Petitioners' future section 205 rate application.[24] NEPGA's concerns can be raised in, and will be taken into account when the Commission reviews, that future section 205 filing. Lastly, the Commission rejects NEPGA's claim that the Project will shift market risk to captive customers and chill the development of competitive resources in New England for two reasons. First, as stated above, there are no captive customers in retail access states. Second, this Project does not limit competition; in fact, we find that it does the opposite

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[20] May 22 Order at P 28 and P 29.

[21] *See, e.g.*, *N. States Power Co.*, 54 FERC ¶ 61,242, at 61,711 (1991); *Cities and Villages of Albany and Hanover v. Interstate Power Co.*, 61 FERC ¶ 61,362, at 62,451 (1992); *California Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,076, at P 301 (2007).

[22] Indicated NE Generators Rehearing Request at 15 - 17.

[23] *Id.* at 19.

[24] May 22 Order at P 67.

and increases competition by offering New England customers an additional supply resource.

B. Merchant Transmission

1. May 22 Order

23. In the May 22 Order, the Commission found that the Project is not a merchant transmission project, and it distinguished the Project from the facilities involved in the recent *Chinook* orders, observing that merchant transmission projects differ from traditional public utilities in that developers of merchant projects assume all the market risk of a project and have no captive customers from which to recover the cost of the project.[25] The May 22 Order stated that the risks of the Project have been shifted from the Petitioners to HQUS, which has agreed to participant-fund the Project and thus has full financial responsibility for the Project. Further, the Commission found that the Petitioners operate in retail access states and have no captive customers. In the May 22 Order, the Commission rejected other related arguments, such as the request for an open season requirement, finding them misplaced, and determined that the Project is a cost-based, participant-funded transmission project that the Petitioners are undertaking at the request of HQUS who has agreed to participant-fund the Project.[26]

24. The May 22 Order required that the Petitioners file the necessary supporting rate application in a future section 205 proceeding, which the Commission will review to ensure that the proposed cost-based rate is just, reasonable, and not unduly discriminatory or preferential. The Commission recognized that the Petitioners want to preserve flexibility to include negotiated rate provisions and other risk sharing provisions in the Transmission Service Agreement that is ultimately filed, but stated that burden will be upon the Petitioners to demonstrate that any such flexible terms and conditions are not unduly discriminatory or preferential at the time they make that filing.[27]

2. Rehearing Request

25. Indicated NE Generators agree that the Project is not a merchant transmission project, but state that the Commission nevertheless should subject the Project to the four-factor analysis used in the *Chinook* order because the Petitioners are proposing to charge

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[25] *Citing Chinook Power Transmission, LLC*, 126 FERC ¶ 61,134, *order on reh'g*, 128 FERC ¶ 61,074 (2009) (*Chinook*).

[26] May 22 Order at P 41.

[27] *Id.* at P 42.

negotiated rates. They argue that the *Chinook* criteria should apply because the negotiated rates for the Project are capped at cost-based rates and because a determination on whether the rates are just and reasonable "turns on the specific elements of the rate proposal," not on whether or not a project is labeled as "merchant."[28] Indicated NE Generators restate their claims that the Project has the potential to shift its costs to captive ratepayers regardless of economic merit, will be a barrier for third-party suppliers from competing for load, and has already blocked potentially competing suppliers for at least twenty years through the long-term power purchase agreement with HQUS. Indicated NE Generators conclude that, whether the Project actually is a merchant transmission project is beside the point, because the effects of the Project on captive ratepayers and alternative suppliers will be detrimental. Indicated NE Generators assert that, under the same circumstances, the Commission would deny negotiated rate authority for a merchant transmission line.[29] Therefore, they claim the Commission erred by not rejecting the proposal.

26. NEPGA states that the Commission failed to distinguish this Project from "other" merchant lines in five areas. First, NEPGA states that the *Chinook* project presented no affiliate issues, unlike the instant Project where a combination of inter-related transactions would contain unspecified "risk sharing" provisions related to completion of the line, making it unclear which party would be responsible for the risk of cost overruns and delays. Second, NEPGA asserts that, there was a significant amount of pre-planning and coordination for the *Chinook* project, but the instant Project dismisses legitimate questions regarding ISO-NE regional planning process. Third, NEPGA argues that the project approved by the Commission in *Chinook* is consistent with open access principles, because it will conduct an open season for much of its capacity and because the open season involves consistent bidding guidelines. In contrast, NEPGA argues, the Petitioners' Project is not consistent with open access principles because it does not provide for an open season, and it grants undue preference to what NEPGA terms a "contractual affiliate." Fourth, NEPGA claims that the project in *Chinook* has no market power issues because there are no captive customers, nor is the *Chinook* project located in an RTO whose members will absorb project costs. In contrast, NEPGA argues, because the Petitioners will be HQUS' customers under the power purchase agreement, the costs of the transmission line will flow through to their captive ratepayers. Lastly,

[28] Indicated NE Generators Rehearing Request at 9 - 10.

[29] *Id.* at 11.

NEPGA states that the Commission erred by not evaluating the proposed Project using the ten criteria it has applied for other merchant transmission facilities.[30]

3. Commission Determination

27. We deny rehearing. As we stated in the May 22 Order, the proposed Project is not a merchant project because the Project is a cost-based, participant-funded transmission project where the risk of the Project has been shifted from the Petitioners to HQUS. Nothing raised on rehearing persuades us that this finding is wrong. Therefore, the four merchant criteria set forth in *Chinook* are not applicable. Therefore, we reject as misplaced any need to evaluate the Project using the merchant criteria established in either *Chinook* or *Northeast*.

28. The Commission believes that some parties may be confused by the Petitioners' use of the term "negotiated rates" for the Project. The fact that the Project participants here negotiated terms and a price subject to a cost-based ceiling does not render those rates "market-based" in the sense that that term is used to denote rates charged by sellers to whom the Commission grants market-based rate authorization, as were the sponsors of the merchant transmission project approved in *Chinook*. As used by the Petitioners, the term "negotiated rate" signifies that the transmission rate ultimately paid by HQUS, while having been negotiated by the parties, is still subject to a cost-based ceiling. Further, consistent with the May 22 Order, we emphasize that the Petitioners must file all cost support data used to develop and derive the transmission rates for this Project required by Part 35 of the Commission's regulations when the Transmission Service Agreement is filed with the Commission. At that time, the Commission will review the rates, terms and conditions contained in that agreement to determine whether they are just and reasonable and not unduly discriminatory or preferential, and all interested parties will have the opportunity to comment on the filing.

C. Bundled Rates

1. May 22 Order

29. In the May 22 Order, the Commission noted that, pursuant to Order No. 888, a transmission provider must functionally unbundle and separately state its generation, transmission, and ancillary services rates. The Commission found that the rates for transmission services and power purchases for the Project meet these Order No. 888 requirements. The Commission also acknowledged that HQUS, but not the Petitioners, will combine renewable hydropower generation costs, which will be sold at market-based

[30] NEPGA Rehearing Request at 6 – 8.

rates, with the costs that HQUS will incur to participant-fund the new transmission line. However, the Commission concluded that such combining of transmission and generation occurs any time a generator purchases long term transmission service to sell power and does not constitute impermissible "rebundling" because the transmission rates are charged under the Transmission Service Agreement, while any power purchases will be separately priced and will occur under HQUS' Commission-approved market-based rate tariff. Charging customers two separately determined and stated rates for power purchases and for transmission service is not inappropriate rebundling, but is fully consistent with Order No. 888.[31]

2. Rehearing Request

30. Indicated NE Generators argue that the Commission erred by approving the structure of the transaction without first reviewing the Transmission Service Agreement and power purchase agreement. Indicated NE Generators contend that the Petitioners' requirement to file, and the Commission's obligation to review, any future jurisdictional rate schedules is insufficient protection from the purportedly bundled rates and their adverse effect on ratepayers. Indicated NE Generators speculate that the Petitioners may argue that the protestors would be collaterally estopped from challenging the structure of transaction because the May 22 Order already concluded that the "rebundled" structure is acceptable. Indicated NE Generators state that, if the Commission allows the transaction structure which results in rebundling, it should conduct a rulemaking to appropriately review all the issues.[32]

3. Commission Determination

31. We deny rehearing. No party has persuaded us that we erred in determining that the proposed transaction complies with the Commission's unbundling requirements. Accordingly, the Commission finds that the proposed transaction is consistent with Order No. 888 because the rates for generation, transmission and ancillary services will be developed separately and the rates, terms and conditions for each service will be stated in separate rate schedules. Therefore, there is no need to review either the Transmission Service Agreement or the power purchase agreement prior to approving the structure of the transaction at this time, nor is there any need to conduct a rulemaking.

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[31] May 22 Order at P 46 - P 48.

[32] Indicated NE Generators Rehearing Request at 23 - 24.

D. Affiliate Abuse Concerns

1. May 22 Order

32. In the May 22 Order, the Commission ruled that the possibility of affiliate abuse does not exist in this case, because Hydro-Québec, HQUS, and any other Hydro-Québec companies are not affiliated with the Petitioners, the transaction was conducted at arms length, and the Petitioners operate in retail access states and thus have no captive customers.[33]

2. Rehearing Request

33. Indicated NE Generators acknowledge that the Petitioners are not affiliated with HQUS or any other Hydro-Québec company, but they argue that the structure of the Project "calls into question the actions of the transmission and distribution segments of the Petitioners' operations."[34] They claim that these business units are engaging in improper affiliate abuse by acting together to discriminate against other potential suppliers in order to assure recovery of costs of the Project. Indicated NE Generators assert that the Petitioners' electric distribution business units would forgo competing supply options, regardless of price, for the first 1,200 MW needed to serve standard offer service customers in favor of HQUS to benefit the transmission units of their respective companies. They claim that the Petitioners benefit, but ratepayers suffer, because the Petitioners will ignore least cost options and favor higher-priced power from HQUS.[35]

3. Commission Determination

34. We deny rehearing. Indicated NE Generators complain that the record evidence in this proceeding indicates that that the transmission and distribution segments of the Petitioners' operation are engaging in improper affiliate abuse by acting together to discriminate against potential suppliers who otherwise could compete to serve the 1,200 MW of load that Petitioners have awarded to HQUS. They contend that Petitioners ignored potentially less expensive options in favor of what appears will be higher-priced power from HQUS, and the Commission erred by not focusing on the potential for affiliate abuse to occur involving the actions of NU's and NSTAR's transmission and distribution segments that are supposed to conduct their activities on a unbundled basis. We find Indicated NE Generators' argument that Petitioners' proposed transaction

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[33] May 22 Order at P 54.

[34] Indicated NE Generators Rehearing Requests at 17.

[35] *Id.* at 17 - 18.

involves improper affiliate abuse to be both unpersuasive and unsupported. Indicated NE Generators' claims that ratepayers will be harmed by the purchase of high-priced hydroelectric power from HQUS are not supported and thus are speculative. We also find that Indicated NE Generators' arguments ignore the fact that neither NU nor NSTAR have captive retail customers; rather their customers have retail choice and can choose which supplier to use. Indicated NE Generators also appears to have ignored the fact that NU's and NSTAR's state regulatory bodies will also review their proposal to ensure that no potential affiliate abuse exists and that retail customers will be buying power from the lowest cost suppliers. Finally, it appears to the Commission that Indicated NE Generators' affiliate abuse allegations are based more upon Indicated NE Generators' continuing claim throughout this proceeding that the Project will likely increase electricity prices and harm customers than upon legitimate concerns of affiliate abuse. The Commission has found both of these concerns to be internally inconsistent and based on speculation unsupported by any analysis or evidence..

E. Vertical Market Power Issues

1. May 22 Order

35. In the May 22 Order, the Commission stated, consistent with well-established precedent, that a minimum requirement for the possession of vertical market power is the ability to control more than one stage of production, in this case, generation and transmission. Here, the Commission noted, the Petitioners are ceding operational control of the Project to ISO-NE and will not be able to use the transmission system, a downstream asset, to control or manipulate generation. The Commission also stated that ceding control of the U.S. portion of the line by the Petitioners to ISO-NE would mitigate any vertical market power. Further, the May 22 Order added that the Petitioners stated, and HQUS confirmed, that HQUS will sell electricity to Petitioners and other interested parties pursuant to HQUS' Commission-approved market-based rate tariff. HQUS also offered to commit in the Transmission Service Agreement to making unused capacity available to third parties pursuant to Order No. 890. In the May 22 Order, the Commission noted that, HQUS must periodically demonstrate that it possesses no horizontal or vertical market power as a condition of being able to sell electricity under this tariff.[36]

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[36] May 22 Order at P 54 and P 55.

2. Rehearing Request

36. Indicated NE Generators state that vertical market power results from the transmission provider owning transmission assets along with 100 percent of the power and then passing on those investments and power contract obligations to a related distribution company. Therefore, they claim that the Commission erred by not focusing on the relationship between the Petitioners' transmission and distribution business units, which, they allege, is the source of vertical market power here.[37]

37. NEPGA questions what type of control ISO-NE will have over the transmission line, and it argues that the Commission cannot conclude that the ISO-NE OATT mitigates vertical market power until it considers the significant differences between this Project and the pool transmission facilities controlled by ISO-NE.[38] Further, NEPGA claims that the May 22 Order failed to consider adequately the bundled nature of the Petitioners' transaction and the vertical market power that will be conveyed. NEPGA argues that the Commission should include a market power test within HQ's Quebec footprint when analyzing HQUS' market-based rate authority.[39] NEPGA concludes that it will be impossible to distinguish the costs associated with the transmission component from the interrelated power supply in a manner that properly protects captive customers.[40]

3. Commission Determination

38. We deny rehearing. As stated in the May 22 Order, a minimum requirement for possessing vertical market power is the ability to control more than one stage of production. In this case, HQUS controls the generation and ISO-NE will have operational control over the Petitioners' transmission line on the U.S. side of the transaction. We reject as speculative and premature Indicated NE Generators' argument that, because the Petitioners own their transmission assets along with 100 percent of the power and will pass these power obligations onto their respective affiliated distribution companies, the transaction will give Petitioners vertical market power. As we determined in the May 22 Order, the Petitioners' ownership of the transmission and distribution lines does not allow them to exercise market power, because ISO-NE will have operational control of the transmission lines. Further, under this transaction, the power will be delivered into ISO-NE for the Petitioners or any other party to purchase under a market-

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[37] Indicated NE Generators Rehearing Request at 18.

[38] NEGPA Rehearing Request at 9 - 10.

[39] *Id.* at 10 and n.27.

[40] *Id.* at 10.

based power purchase agreement with HQUS. Thus, any assumption that the Petitioners will purchase 100 percent of that power is premature and speculative. As stated previously, because the Petitioners' end-use customers have retail choice, HQUS cannot exercise vertical market power.

39. The Commission dismisses as premature NEPGA's concerns over the type of control that ISO-NE will have over the transmission line due to its nature (and potentially differences with pool transmission facilities). The Petitioners have agreed to turn over operational control of the transmission line to ISO-NE, and this will mitigate any vertical market power concerns. Further, the Petitioners must file the Transmission Operating Agreement with the Commission, and this agreement will provide the specific details regarding ISO-NE's operating responsibilities with respect to the transmission line. All interested parties will have an opportunity to review the provisions contained in the Transmission Operating Agreement at that time, and the Commission's evaluation of the Transmission Operating Agreement will be informed by the comments received on the proposal, as well as its own analysis. Lastly, we reject as outside the scope of this proceeding NEPGA's request for a market power test within HQ's Quebec footprint when analyzing HQUS' market-based rate authority.[41]

F. ISO-NE's Regional Planning Process

1. May 22 Order

40. In the May 22 Order, the Commission accepted ISO-NE's and Petitioners' statements that the Project will be thoroughly vetted through the ISO-NE's regional system planning process. The Commission noted that, under ISO-NE's regional system planning process, ISO-NE, in consultation with stakeholders and other interested parties, is responsible for determining whether any reliability transmission upgrades are needed to interconnect the Project to the regional AC transmission system. The Commission found that the Petitioners will be responsible for the costs of the Project as well as any network upgrades to the existing ISO-NE transmission system needed to accommodate the line. The Commission also accepted Petitioners' representations that they will submit a Transmission Operating Agreement to ISO-NE for its approval, and that the Project will undergo ISO-NE's section I.3.9 reliability review process to ensure that it does not cause any adverse effects to system reliability. The Commission concluded that, because ISO-NE commits to playing an active role in reviewing the effects of the project and ensuring that the reliability review process is transparent vis-à-vis the U.S. portion of the line, this

[41] NEPGA Rehearing Request at 10, n.27.

oversight will address any potential that other parties would be required to pay for facilities to accommodate the interconnection of the transmission line.[42]

2. Rehearing Request

41. Indicated NE Generators assert that Order No. 890 requires that the Project be subject to ISO-NE's regional planning process in order to prevent undue discrimination and to promote open access. They argue that the benefits of the regional planning process can be lost if all transmission expansion projects are not evaluated through a coordinated process. Indicated NE Generators claim that the Petitioners ignored the Commission's Order No. 890 coordination requirement by not participating in ISO-NE's transmission planning process and that the Commission erred by granting the Petition in alleged contradiction to the coordination requirements of Order No. 890.[43]

42. Further, Indicated NE Generators claim that the Commission erred in two ways by ruling that, because the Project was participant-funded, ISO-NE need not assess the Project or its economics because the costs of the Project will not be included in transmission rates. First, as stated previously, Indicated NE Generators assert that the Project is not participant-funded but will be paid for by Petitioners' ratepayers. Second, they argue that, even if the Project is participant-funded, that would not justify the Commission ignoring its finding in Order No. 890 that the regional system planning process can succeed only if all transmission owners participate.[44]

43. Indicated NE Generators state the Commission ignored evidence that the Petitioners structured the transactions to avoid an assessment of need for, and the economics of, the Project as compared to other alternatives. Indicated NE Generators contend that the Petitioners acknowledged that they were not pursuing the Project through ISO-NE's regional system planning process and would only go forward with building the Project if they could demonstrate to ISO-NE that the economic benefits for New England outweigh the costs of the line.[45]

44. Indicated NE Generators claim that the Petitioners' statement that they "plan" to bring the Project into ISO-NE's planning process to determine the effect of the Project on the regional transmission grid is irrelevant because the Petitioners excluded the Project

[42] May 22 Order at P 63.

[43] Indicated NE Generators Rehearing Request at 21.

[44] *Id.* at 22.

[45] *Id.*

from the normal planning process. Indicated NE Generators assert that the May 22 Order fails to mention that, because the Project has by-passed the regional system planning process, the ISO-NE stakeholders have been denied the opportunity to consider and coordinate appropriate size and other key factors with other regional expansion projects. They also assert that the Petitioners avoided the regional planning process because the Project is not needed for reliability purposes and is being built for economic benefit of the Petitioners, not ratepayers. Thus, Indicated NE Generators conclude that the May 22 Order ignores Order No. 890's planning requirements and contradicts Commission precedent.[46]

3. **Commission Determination**

45. We deny rehearing. In the May 22 Order, we found that the Project will be appropriately vetted through the ISO-NE stakeholder process, and that ISO-NE, in consultation with interested parties, will be responsible for determining whether any reliability upgrades will be needed to interconnect the Project to the regional AC transmission system.[47] The May 22 Order also noted that ISO-NE already has determined that the Project would not be considered an elective upgrade because it is not a pool transmission facility, would not fit under existing OATT provisions, and that participant-funding is a logical option. The May 22 Order stated that ISO-NE agreed to play a key role in ensuring a transparent decision-making process for the southern terminus of the transmission line to ensure that the entire region does not need to support any network upgrades resulting from the Project.[48]

46. Therefore, based on ISO-NE's comments supporting the Project and its representations that the Project will be thoroughly vetted through its stakeholder process and that ISO-NE will play a key role in ensuring that the transmission line will not adversely affect reliability or operations, the Commission rejects as without merit Indicated NE Generators' concerns over the Project's place in ISO-NE's regional planning process.

4. **Request for Clarification**

47. Indicated NE Generators states that ISO-NE's OATT requires participant-funding of any additions to or modifications of any pool transmission facilities or non-pool

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[46] *Id.* at 22 - 23.

[47] May 22 Order at P 63.

[48] *Id.* at P 60 and P 61.

transmission facilities that are required to accommodate a participant-funded project.[49] Indicated NE Generators claim that the May 22 Order did not address the issue of whether the Petitioners should be required to pay for all AC transmission reinforcements necessary to accommodate the proposed Project's interconnection. Indicated NE Generators also request that the Commission clarify that it is the Petitioners' responsibility to fund all such reinforcements, because the Petitioners may later argue that the Commission's May 22 Order endorsed a cost recovery mechanism under which the Petitioners will recover the cost of AC transmission upgrades from all ratepayers, even if these upgrades do not benefit all transmission customers in the region.[50]

5. Commission Determination

48. As stated in the May 22 Order and ISO-NE's comments supporting the participant-funded proposal, the proposed Project would not be considered an elective network upgrade or a pool transmission facility (PTF) and would therefore not fit under existing ISO-NE OATT provisions.[51] Further, ISO-NE states that the Project's southern terminus could have major impacts on the existing and planned New England transmission network, and that choosing a sub-optimal location for the end of the transmission line could create the need for other, internal transmission upgrades to be constructed to deliver the energy to the load, which might drive the need for additional Reliability Transmission Upgrades that would be eligible for regional cost support.[52] The Commission agrees with ISO-NE. Since the instant Project does not fit under any of ISO-NE's current OATT provisions two points need to be clarified. First, since the instant Project is participant-funded, the Project itself would not be reviewed under ISO-NE's entire regional system planning review process that other reliability projects which have potential cost-sharing concerns are subject to. Rather, as the May 22 Order states this Project will undergo ISO-NE's section I.3.9 reliability review process to ensure that it does not cause any adverse effects to system reliability.[53] Second, the Commission finds that since it is not possible to know precisely what impacts the placement of the

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[49] Indicated NE Generators Rehearing Request at 24 and n.41, which references Section II.47.5(d) of ISO-NE's OATT, which states that participant-funding is required for "any additions to or modifications of the PTF or Non-PTF that are required to accommodate the Elective Transmission Upgrade."

[50] *Id.* 24 - 26.

[51] May 22 Order at P 60 and ISO-NE's comments at 7.

[52] ISO-NE comments at 8.

[53] May 22 Order at P 63.

Project's not yet determined southern terminus might have on ISO-NE's transmission system at this time, that it is premature to speculate as to whether any costs, may be eligible for regional cost-sharing resulting from the instant Project. The Commission emphasizes that this Project is participant-funded and the Petitioners are not asking at this time for any other parties to share in its costs. . If Petitioners seek to recover costs of transmission upgrades related to the Project at some point in the future, Indicated NE Petitioners are free to raise those concerns in comments on Petitioners' request for cost recovery. For these reasons, the Commission denies Indicated NE Generators' request for clarification, finding that such concerns are premature.

G. Lack of Sufficient Information to Support the Filing

1. May 22 Order

49. In the May 22 Order, the Commission found that it did not require any additional information to approve the structure of the transaction, given that the Petitioners agreed to file all appropriate section 205 rate applications, including the cost support required by Part 35 of the Commission's Regulations.[54] In particular, the Commission rejected as premature the protesters' requests for additional information about the Transmission Service Agreement and the power purchase agreement, given that power sales will occur under HQUS' Commission-approved market-based sales tariff. Lastly, the Commission reminded the Petitioners that they will be required to file, when appropriate, the Transmission Service Agreement and the Transmission Operating Agreement and emphasized that the Petitioners must file any other agreements related to the Project not otherwise discussed in the Petition that involve jurisdictional services.[55]

2. Rehearing Request

50. On rehearing, Indicated NE Generators repeat their argument that the Petitioners did not provide information critical to understanding the proposed arrangement between the Petitioners and HQUS. They state that, because of this deficiency, the Commission did not have sufficient information to understand the various aspects of the proposal. Indicated NE Generators contend that the Commission erred by approving "the structure" of the transaction before seeing the Transmission Service Agreement and the power purchase agreement. Indicated NE Generators state that, at a minimum, the Commission should vacate its approval of the structure as proposed by the Petitioners and should defer

[54] 18 C.F.R. § 35.13 (2008).

[55] May 22 Order at P 76.

ruling on the proposal until it has reviewed all agreements, obligations, and tariff proposals associated with the Project.[56]

3. Commission Determination

51. We deny rehearing. In the May 22 Order, the Commission rejected as premature requests for additional information concerning the Transmission Service Agreement and the power purchase agreement, while reminding the Petitioners of their obligation to file at the appropriate time the Transmission Service Agreement, the Transmission Operating Agreement, and any other agreements related to the Project not otherwise discussed in the Petition that involve jurisdictional services. The Commission will not review the market-based power purchase agreement because HQUS is not required to file this agreement with the Commission. However, HQUS, consistent with the Commission's quarterly reporting requirements,[57] will report the sale transactions, which the Commission will duly review, and the power purchase agreements will be filed and reviewed by the appropriate state commissions. Therefore, we find no new compelling reasons to require the Petitioners to file any additional information at this time. Again, all parties including the Commission will have an opportunity to review the Transmission Service Agreement, the Transmission Operating Agreement, and all other jurisdictional rate schedules when they are filed with the Commission.

H. Monopsony Power and Impact on the Forward Capacity Markets

1. May 22 Order

52. In the May 22 Order, the Commission found that the issues raised by Protestors concerning the adequacy of the existing forward capacity market rules were beyond the scope of the instant proceeding. The Commission stated that any concerns regarding the forward capacity market rules are best addressed in the ISO-NE stakeholder process.[58]

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[56] Indicated NE Generators Rehearing Request at 23 - 24.

[57] *Revised Public Utility Filing Requirements*, Order No. 2001, FERC Stats. & Regs. ¶ 31,127, *reh'g denied*, Order No. 2001-A, 100 FERC ¶ 61,074, *reh'g denied*, Order No. 2001-B, 100 FERC ¶ 61,342, *order directing filing*, Order No. 2001-C, 101 FERC ¶ 61,314 (2002), *order directing filing*, Order No. 2001-D, 102 FERC ¶ 61,334 (2003).

[58] May 22 Order at P 81.

2. Rehearing Request

53. Indicated NE Generators argue that, by approving the structure of the Project, the May 22 Order undermines the existing forward capacity market in New England. According to Indicated NE Generators, this is significant because existing generation suppliers have not been given an opportunity to compete to provide capacity or energy to the 1,200 MW of load that would be served under the HQUS power purchase agreement. Indicated NE Generators state that such a large acquisition by the Petitioners can artificially suppress the market clearing price paid to all capacity resources, generation and demand response, through the intended or unintended effects of monopsony power. They assert that, when the Petitioners procure new resources outside of the market, they will be placed in the supply stack as price takers, causing higher cost new entry projects to not set market prices.[59]

54. Indicated NE Generators also argue that in a competitive market such as ISO-NE, the way to determine what resource is the least cost option is to conduct a transparent and competitive procurement process. They acknowledge that the forward capacity market is where such competition should occur, but they maintain that the price of capacity in this market should not be manipulated by large load-serving entities that are allowed to exercise monopsony power.[60]

55. Indicated NE Generators explain that they did not argue that there was a need to revisit the forward capacity market rules, but they were merely pointing out that the alternative price rule in the forward capacity market rules "is only applicable in years in which new capacity is needed and therefore does not mitigate the exercise of monopsony power in circumstances such as those that exist today in New England in which there is a surplus of capacity."[61] Indicated NE Generators state that they made that observation not to argue that the forward capacity market rules should be modified, but rather to show that market rules do not negate the detrimental effects on the market if the Project goes forward. Thus, Indicated NE Generators claim that the Commission erred by failing to address the substance of its argument and by disposing of it on procedural grounds.[62]

[59] Indicated NE Generators Rehearing Request at 19.

[60] *Id.* at 20.

[61] *Id.* at 20 - 21.

[62] *Id.* at 21.

3. **Commission Determination**

56. We deny rehearing. If the entry of new generation will have such a deleterious effect on the market that suppliers are not able to earn what they view as sufficient revenue, as Indicated NE Generators contend, then the question is whether this entry is uneconomic. For new capacity to be "uneconomic", entry means that it costs more to bring this capacity to market than it would to simply buy capacity in the current forward capacity market. But there must also be an economically rational reason for doing so: net-buyers in a capacity market have the incentive to bring such capacity to market in order to lower their overall capacity payments. The ISO-NE forward capacity market has rules dealing with uneconomic entry of new capacity resources, and any issues involving the alleged insufficiency of the forward capacity market rules, including whether the forward capacity rules send appropriate price signals, are beyond the scope of this proceeding. Indicated NE Generators may raise any concerns regarding forward capacity market rules through either the ISO-NE stakeholder process or an appropriate filing with this Commission. Further, Indicated NE Generators simply repeat arguments raised and resolved in other proceedings, specifically, the Commission orders approving the Forward Capacity Market Settlement and rules.[63] Again, these arguments are outside the scope of this proceeding.

The Commission orders:

(A) Indicated NE Generators' and NEPGA's rehearing requests are hereby denied, as discussed in the body of this order.

(B) Indicated NE Generators' request for clarification is hereby denied, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[63] *ISO New England Inc.* 122 FERC ¶ 61,018, at P 4 (2008), *Devon Power LLC,* 115 FERC ¶ 61,340, at P 109 (2006), *order on reh'g,* 117 FERC ¶ 61,133 (2006), *NSTAR Electric Co. v. ISO New England Inc.* 125 FERC ¶ 61,187, at P 26 (2008), *ISO New England Inc.*, 123 FERC ¶ 61,290, at P 16 (2008).