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To: NECA Board of Directors

From: The Power Markets Committee

Date: January 10, 2008

Re: Power Markets Committee Report

Chair: Peter W. Brown, Esq.

The following is the report of the Power Markets Committee ("PMC") for the January 10, 2008 Board meeting. Contributors to this report are Chris Bursaw, Joe Cavicchi, Michelle Gardiner, Paul McCary, Mark Magyar, Dan Maserang, Seth Parker, Matt Picardi and Peter Brown.

1. Energy Independence and Security Act of 2007

On December 19, 2007, President Bush signed the Energy Independence and Security Act of 2007. The Act chiefly addresses national fuel economy standards ("CAFE") by increasing fuel economy standards by 2020 to 35 mpg. The Act also requires alternate fuel sources, chiefly biofuels, to increase to 36 billion gallons/year by 2022. Lighting standards and appliance efficiency standards are also prescribed, with the demise of the standard electric light bulb scheduled for 2014.

What the Act did not address is extension of renewable energy tax benefits, a nationwide renewable portfolio standard or a national greenhouse gas regulatory regime. It is expected that these issues will be addressed in ensuing sessions of the Congress.

2. The Technical Conference of the Federal Energy Regulatory Commission – Interconnection and Queuing Issues

On December 11, 2007, the Federal Energy Regulatory Commission ("FERC") held a technical conference on generator interconnection and queuing practices. Representatives from

the region's state regulatory bodies, ISO-New England and the private sector testified. Testimony and written submissions were received from all regions of the country.

Suffice it to say, it is likely that there will be changes in the large generator interconnection rules (Order No. 2003-A, B & C) as a result of the testimony and information received by the commissioners. In New England, Commissioner Anne George of Connecticut described the problems with the current queue and the work of the stakeholder group that has been empanelled to address the problems with queue. A filing on "queue reform" for New England is due in October of 2008. During the course of the technical conference testimony was received concerning the severe problems with interconnection and queuing in the Midwest and upper Midwest where several thousands of MWs of wind farm development await interconnection studies. California representatives testified to the same effect. Various proposals to address the problems were described. California is seriously considering "cluster" interconnection studies. Colorado has enacted legislation to establish "Renewable Energy Transmission Zones" similar to the "Competitive Renewable Energy Zones" ("CREZ") established for West Texas in legislation enacted in 2005. Developers advocated a "roll in" of all upgrade costs associated with generator interconnection requirements.

As described by the "cluster" advocates, individual projects in the queue would be aggregated for a single interconnection study with the assumption that all projects would be built. Upon completion of the study costs of upgrades would be assigned based on a formula (e.g. capacity ratio share). Projects that did not commit to their share of costs would be dropped from the queue.

In the CREZ approach, if developers in the zone post a letter of credit of 10% of estimated project costs, the transmission provider builds the upgrades necessary for the interconnection. All upgrade costs are allocated to all ratepayers in the jurisdiction in question (in the case of Texas, all of Texas).

Recordings of the conference on FERC's webcast are archived for three months and can be accessed via the FERC website under Docket AD08-2-000. Written submissions may also be obtained under this docket number.

3. **FERC Docket No. ER07-1415-000**
Xcel Energy Services, Inc.
Order Granting Incentives, and Accepting Proposed Rate Formula Modifications,
Subject to Conditions
Order Issued: December 21, 2007

In the above-referenced order Xcel Energy Services Inc. (also referred to as NSP Companies) was granted "two types of incentive rate treatment for 6 projects:

- 100 percent of prudently incurred Construction Work in Progress (CWIP) in rate base

- Recovery of 100 percent of prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond their (Xcel's) control.”
(Commissioner Kelly, concurring decision)

Xcel intends to more than double its investment in transmission facilities in five states as a result of the six transmission projects.

The ordered incentives are argued to be “limited and tailored to support major transmission construction that is required to improve reliability and to relieve congestion in the region.” In most respects the transmission investments are intended to enable renewable (wind) generating resources to access power markets in the upper Midwest. A related aspect of the investments was that facilitating wind energy development via the investments would enable Minnesota to meet its renewable portfolio requirements. The ordered rate treatment applies to about 1.6 million retail customers of Xcel in Minnesota, North Dakota, South Dakota, western Wisconsin, and the western tip of the Upper Peninsula of Michigan.

To receive the rate incentives, the Xcel companies must obtain a Certificate of Need from the Minnesota Public Utility Commission. There is a “true-up” procedure to assure proper cost recovery.

The Commission noted:

In the Energy Policy Act of 2005 (EPACT 2005), Congress addressed the allowance of incentive-based rate treatments for new transmission construction. Specifically, section 1241 of the EPAct 2005 added a new section 219 to the FPA directing the Commission to establish, by rule, incentive-based (including performance-based) rate treatments. The Commission issued Order No. 679, which set forth processes by which a public utility could seek transmission rate incentives pursuant to section 219, including the incentives requested by the NSP (Xcel) Companies.

The Commission also noted:

The Commission has clarified that it retains the discretion to grant incentives that promote particular policy objectives unrelated to whether or not a project presents specific economic risks or challenges.

... this nexus test is fact-specific and requires the Commission to review each application on a case-by-case basis.

4. Order No. 890-A, FERC affirms Order No. 890 reforms, with some modifications and clarifications in the following areas

In an order issued December 20, 2007 FERC affirmed Order 890 (reforms to the open access transmission tariffs) and modified that order in some minor respects. The modifications were:

- a. Available transfer capability calculation frequency standards should serve as a minimum requirement and, in the absence of substantial and material changes in data, transmission providers are not required to update ATC more frequently than that minimum standard.
- b. Calculation of incremental costs for purposes of assessing imbalance charges based on the last 10 MW dispatched to supply the transmission provider's native load will be based on the actual cost to correct the imbalance, which may be different than the cost of serving native load. OATTs must clearly specify the imbalance charge methodology.
- c. The price cap on reassignments of transmission capacity is reinstated as of October 1, 2010.
- d. The discount rule or the price ceilings otherwise stated in the transmission provider's OATT do not apply to reassignment of capacity.
- e. Transmission providers, in coordination with NERC and NAESB will develop a consistent set of tracking capabilities and business practices for tagging for implementation of conditional firm service.
- f. Posting requirements apply to all requests for service, including requests for point-to-point service and requests to designate new network resources or loads.
- g. Transmission customers will not lose their underlying transmission service agreement simply because they failed to comply with the requirements of extending the service commencement date (but they will lose the right to the extension).

5. FERC Clarifies its Order 697 on Market Based Rates

On December 14, 2007 The FERC issued an order clarifying its market based ratemaking authorization set forth in Order 697 from this past summer.

- a. The requirements of Order 697 apply as of the effective date (September 18, 2007), regardless of when tariffs are actually amended. Thus, for example, the new provisions apply to a company as of September 18, even though the actual amendments will not be submitted until company updates are filed.
- b. All affiliates in the same region are to file at the same time as the transmission owning utility.

c. For the market share screen, the four seasons are to be used (i.e. summer = June, July and August), not the calendar quarters. The historical year to be used is the last year ending November 30, for which data are available and non-transmission owning sellers are to use the same historical test year as used by the transmission owners in the same region. Thus, a June 2008 filer in a region where the TO filed in December 2007, is to use data for the year ending November 30, 2006. For filings due soon, the test year period is 12/1/05-11/30/2006.

6. Revised Filing Requirements for Electric Quarterly Reports

A source of useful information about markets and market behavior is the Electric Quarterly Reports (“EQRs”). Each company that is subject to regulation under Section 205 of the Federal Power Act must file reports that summarize contractual and wholesale market transactions on a quarterly basis.

On December 21, 2007, the FERC issued Order No. 2001-H that clarifies previous orders involving EQRs (Order Nos. 2001, A, B, C, D, E, F and G). In this most recent order the FERC clarified reporting requirements for the commencement dates of reported contracts and rate descriptions and corrected an inadvertent error in the regulations.

7. Developments in Neighboring Markets

a. New York ISO (“NYISO”) In-City Mitigation Proposal

On October 4, 2007, NYISO submitted a Compliance Filing to FERC regarding the ICAP Market Structure in New York City (“NYC”) (Docket No. EL07-39-000). This docket addresses the FERC’s directive that the NYISO review its in-city capacity market design to ensure its justness and reasonableness. Concerns surrounding the market arose following claims of economic withholding in the NYC capacity market last year after 1,000 MW of capacity entered the market, but spot capacity market prices continued to clear at the mitigated offer cap (\$105/kW-yr ICAP converted to UCAP) implemented when Con Ed divested its generating portfolio. NYISO originally filed a Con Ed / Department of Public Service (DPS) proposal to establish an \$82/kW-yr price cap on December 22, 2006. Although the proposal had received stakeholder approval, FERC rejected it in a March 6th Order in favor of a stakeholder settlement process to resolve multiple issues. The settlement process was unsuccessful, and as a result, FERC issued a July 6th Order directing the NYISO to file modifications to the in-city market power mitigation proposal that would ensure it produces just and reasonable prices going forward.

NYISO’s October 4th Compliance Filing introduces new market power mitigation protocols which (i) cap capacity bid prices to mitigate market power of sellers and (ii) set a floor price for new capacity to mitigate buyer market power, each described below. NYISO also addressed the subject of a forward capacity market, but declined to make any specific proposals while a stakeholder process is underway. Lastly, NYISO did not think that refunds for customers were necessary, since the “market outcomes have been consistent with the

Commission’s expectations in approving mitigation measures in connection with the Con Ed divestiture.”

(i) Seller Market Power Mitigation

A key element of the proposal is the implementation of a “default reference level” that would cap bid prices for pivotal suppliers, and require them to offer their unsold capacity into the Spot Market auctions.¹ Pivotal suppliers are bidders who own or control an amount of capacity needed to meet the NYC locational capacity requirement, such as the divested generation owners (DGOs). The default reference level would replace the previously proposed \$82kW-yr cap and be calculated by NYISO in advance of each Spot Market auction as the price at which all NYC capacity would clear.² Exceptions could be granted on a case-by-case basis. Bidders with less than 500 MW of UCAP would not be considered pivotal and would therefore be exempt. In addition, both the DGO offer cap and revenue cap would be eliminated.

(ii) Buyer Market Power Mitigation

Another key feature is a three year floor price for new capacity bids to prevent monopsony power from “artificially” depressing prices. This would occur if a buyer entered into a capacity contract and then submitted a low (even zero) priced capacity bid into the Spot Market auction, thus lowering the market capacity price and reducing the cost of other capacity purchases. In this Compliance Filing, submitting a low capacity bid for incremental generation addition is termed “uneconomic entry” because the buyer would be compensated for the revenues “lost” on the uneconomic transaction by saving money on all other market capacity purchases. The proposed mitigation is to set a three year floor at 75% of net cost of new entry (“CONE”) for new entry, including capacity imports via controllable transmission lines. As with seller bid caps, exceptions could be granted to buyers on a case-by-case basis.

(iii) Comments and Reply Comments

Both generators and buyers have filed comments and reply comments to NYISO’s proposal. Without presenting specific positions, the generators have suggested: (i) the buyer’s market power mitigation is too lenient, and the floor price should be increased to 90% or even 100% of net CONE; (ii) the floor price should be in effect for more than 3 years; and (iii) NYISO should implement a forward capacity market as soon as possible. The buyers, on the other hand, have suggested: (i) refunds should be required as of mid-2006, (ii) no buyer market power mitigation is necessary; and (iii) revenue caps for DGOs should be maintained.

¹ While offering capacity into the Spot Market auction is generally voluntary, owners of divested Con Ed generation have been required to bid that capacity.

² The default reference level can be calculated as the intersection of a vertical line extending from a zero-priced capacity supply curve (including capacity imports via controlled cables) to the point on the NYC demand curve.

b. PJM Developments

(i) The Power Edge Default

PJM experienced its second default in the past three months. Power Edge LLC is in default for its November payment on the company's open FTR counterflow positions acquired during the spring 2007 annual FTR auction. The estimated payment default for its November invoice through to May 2008 is \$80 million.

In October, PJM members were notified that another member, Exel Power Sources, LLC was in payment default. Consequently, Exel's aggregate payment default is \$4.5 million through November with additional charges likely through May 2008.

On December 21, PJM submitted a filing to the FERC, which enhanced the existing credit policy for FTRs. PJM's proposal, supported by its Members Committee, would tighten collateral requirements for FTRs to better reflect congestion volatility based on an evaluation of monthly congestion patterns over the last three years. This would permit PJM to require additional credit collateral as market participants bid on FTRs, instead of waiting until congestion charges occur.

FTRs are financial rights that provide PJM market participants with a hedge against transmission congestion charges in the day-ahead energy market. Counterflow FTRs, which Power Edge LLC purchased, are an opposite hedge for participants. They are financial rights associated with the flow of power on a transmission line in the opposite direction of a transmission constraint. A member using the line to transmit power would pay the counterflow FTR purchaser a fee.

In the 2007 annual FTR auction, PJM for the first time saw unprecedented new interest by new participants in bidding solely for counterflow TR positions. The FTR portfolios of some of the new participants are not as diverse as those of most other market participants and therefore more vulnerable to changing system conditions. PJM believes that the current credit conditions are not due to the FTR auction design, but rather the result of the narrowly focused FTR portfolios of these companies and less diverse total market positions taken by new entrants into the PJM market.

(ii) The Market Monitor Settlement

On other PJM matters, on December 19, PJM announced that it had filed a settlement with the FERC that resolved the future structure and independence of the PJM Market Monitoring unit.

The settlement agreement would result in market monitoring services being provided by an external firm, Monitoring Analytics, LLC, to be headed by Dr. Joseph Bowering, the current, internal market monitor. The parties also agreed on a means to provide confidential market information to state commissions and to protect such information from being inappropriately released.

Key provisions under the settlement include:

- Under the PJM tariff, the Market Monitoring Unit (MMU) will be an independent, external entity under contract with the PJM Board and approved by the FERC. No one will have the right to interfere with or edit MMU actions, investigations or reports.
- The initial market monitoring contract will be for six years beginning June 1, 2008.
- The contract can only be terminated with FERC approval.
- The settlement provides the MMU with direct access to PJM data and ensures the MMU's ability to control its information technology and data.
- The market monitor's proposed annual budget for market monitoring services would be reviewed by the PJM Finance Committee, the PJM Board and representatives of state regulators. Disputes over the proposed budget would be resolved by the FERC.
- State commissions would be able to receive confidential information from PJM or the MMU provided the state commissions certify to the FERC that they have adequate procedures to protect against release of the information.

The settlement discussions were instituted by a FERC order in September. In response to a complaint about PJM's interaction with the Market Monitoring Unit and the issue of its independence, the commission found that PJM had not violated its tariff. The commission found that significant tension between PJM management and the market monitor could compromise the MMU's ability to perform its tariff-defined functions and found that the market monitor should no longer report to PJM management.

(iii) PJM Reevaluates the Cost of New Entry ("CONE")

Of additional significance in PJM is the recent report of the consultant, Ray Pasteris, hired by PJM to reevaluate CONE. Using a proxy unit of two GE Frame 7FA, dry low Nox with dual fuel capability, as well as updated costs and financial assumptions, CONE was reevaluated in three regions in PJM; EMAAC, SWMAAC and RTO. In general, installed costs for these regions have climbed from roughly \$470/Kw to just over \$600/Kw in each of the regions. PJM intends to make a FERC filing to update CONE, as used in its demand curves for the May '08 auction serving delivery year 2011/2012.

As explained in the attached report from PJM's consultant, Mr. Ray Pasteris:

"Please be advised that the capital cost and annual fixed O&M values are slightly different from those posted previously on the PJM website prior and for the December 13, 2007 MRC meeting. Changes to Emissions Reduction Credits cost assumptions affected CONE capital costs and property tax escalation assumption affected fixed O&M expenses. Please use the results of this report for your evaluation and analysis of CONE."

c. New York Public Service Commission – Order on “Backstop Reliability Projects”

On December 24, 2007, the New York State Public Service Commission (NYPSC) issued its order initiating a collaborative proceeding to recommend a process to assist the Commission in selecting regulated, backstop projects to meet reliability needs in the event market-based solutions are unavailable. The NYPSC also ordered the collaborative proceeding to develop a long-term, 10 to 15 year, electric resource plan to provide guidance to the Commission in exercising reliability backstop responsibilities and to address the long-term public policies, goals, and needs of New York.

The NYPSC expects the parties in the collaborative process to address issues and make recommendations to the NYPSC to assist it in making policy in future orders. The kick-off meeting for the collaborative process is scheduled for January 11, 2008.

The discussion between the commissioners and the administrative law judge at the NYPSC’s December 19, 2007 session appeared to indicate that the NYPSC would reaffirm competitive markets and emphasize that investment risks should be borne by private developers, not utility ratepayers, and that utility long-term contracts would only be required as a last resort if market solutions did not meet reliability needs. While the NYPSC did, in fact, make these statements in its December 24 Order, it also made clear its expectation that it would need to rely on regulatory approaches to meet public policy goals because the competitive markets may fail to meet these needs. The NYPSC stated:

"Nevertheless, we acknowledge that markets are only one of the tools we can use to achieve the ends dictated by the PSL. We will utilize regulatory approaches, as we have in the recent past, should the market not address the energy needs and related public policy goals of the State, but such efforts must be judiciously used keeping in mind their impacts on both consumers and markets."

The NYPSC proposed that public policy goals, such as fuel diversity, generation diversity, environmental externalities, energy efficiency, environmental justice, security and sustainability of fuels, relative cost effectiveness of demand and supply side measures, economic development, affordability of rates, global warming emissions, transmission investment, and demand response programs may be considered in the context of the review of backstop proposals.

In addressing the need for a long-range electricity resource plan, the NYPSC noted that NYISO’s Comprehensive Reliability Planning Process was not designed to promote infrastructure additions that could help meet public policy goals once reliability is met. The Commission also noted that investment risks may need to be borne by utility ratepayers. It stated:

"An energy policy that calls for a more diversified portfolio of generation fuel than strictly natural gas is not expected to succeed if left to today’s market structure. Accordingly, to achieve State energy policies and goals, it may be necessary to shift some of the capacity investment risk back to consumers, a result that is achieved in part using long-term contracts."

The NYPSC's Order is of concern because if, in its opinion, its stated goals cannot be met by a market structure, then they would have to be met through a state regulated structure that would serve only to increase uncertainty and risk to market solutions.

d. NYISO 2008 Reliability Needs Assessment for the 2008 Comprehensive Reliability Planning Process

NYISO implemented its Comprehensive Reliability Planning Process (CRPP) in 2005 to assess and establish necessary measures for bulk power system reliability on an annual basis. The first step is a Reliability Needs Assessment (RNA) which evaluates the adequacy and security of the bulk power system over the next ten years. The RNA identifies the amount of resources required ("compensatory megawatts") to meet reliability criteria and their locations, and if the expected market solutions (i.e. generation additions) will satisfy the reliability criteria.

The most recent RNA report was released on December 10, 2007 and summarizes the needs assessment for NYISO. The reliability of the bulk power transmission facilities was analyzed both in terms of its security and its adequacy. The RNA study indicates that the forecasted system will violate the 0.1 days per year reliability criterion starting in 2012, or in 2013 with Neptune modeled as firm capacity. NYISO lists 3,007 MW of expected market solutions that should avoid the need for regulated "backstop" solutions. These market solutions include 1,497 MW of questionable generation additions (Spagnoli Road, Astoria GT repowering, Indian Point GT, and Arthur Kill CC) and 1,510 MW of cable projects (Linden VRT, Hudson Transmission Partners, and Bergen / Cross Hudson). In addition, there are 455 MW of generation additions already under construction or in advanced development (Gilboa uprates, Prattsburg wind, and Caithness CC), and 1,428 MW of planned retirements (Lovett 5, Russell 1-4, Poletti, and Astoria GTs). The additions do not include the Besicorp-Empire CC project, which could add another 500 MW.

Downstate load growth is placing increased demands in Zones G through K, across the UPNY/SENY interface, and especially downstream of Dunwoodie / Sprain Brook. The local TOs are installing transmission upgrades to increase the transfer limit from Zone I into Zone J from 3,925 MW in 2008 (thermal limit) to 4,400 MW by 2010 (combined limit). The UPNY/SENY and Zone I / Zone K interface limits are unchanged from 2008 through 2012.

8. Maine and Secession From NEPOOL – The Maine Public Utilities Commission ("MPUC") Report on Continued Participation in RTO by Maine Utilities (MPUC Docket No. 2006-364)

On December 3, 2007 the Maine Public Utilities Commission ("MPUC") issued for comment a Draft Final Report to the Maine Legislature's Utilities and Energy Committee regarding its inquiry into the continued participation by Maine Transmission and Distribution Utilities in the New England RTO. This report is in response to a directive to the MPUC from the Maine Legislature to evaluate alternatives to the NEPOOL/ISO status quo arrangements that Maine could pursue to advance its interests with respect to electricity prices and reliability, and state environmental goals. The MPUC was directed to submit a Final Report to the Legislature

on January 1, 2008 and had requested comments from interested parties on or before December 21, 2007.

The MPUC identified the following three options that the MPUC stated would support the development of diverse, renewable and low CO₂ resources, and more reasonably treat Maine's interests within the applicable market and regulatory systems than the status quo: (1) remain within the existing RTO (the "Market Reform Option") but work on key reforms to address necessary transmission upgrades, market impacts that currently discourage development, the role of the New England States Committee on Electricity ("NESCOE"), equitable transmission cost allocation, and RTO governance and accountability; (2) pursue withdrawal of the Maine PTOs from the RTO coupled with formation of one or more ITCs; or (3) form a Maine/Canadian Maritimes market/Control Area. Timely comments on the MPUC's Draft Final Report were filed by various parties. At the highest level, the comments generally recommend that Maine pursue the so-called Market Reform Option rather than the Maine ITC or ME/NB Options.

9. Maine Examines Utility Owned Generation – The MPUC Report regarding the Reentry of Electric Utilities into the Energy Supply Business (MPUC Docket No. 2007-317)

On December 10, 2007, the MPUC issued for comment a Draft Report titled Transmission and Distribution Utilities Participation in the Energy Supply Business for submission to the Maine Legislature's Utilities and Energy Committee. The MPUC was directed to submit its final report to the legislature on January 15, 2007 and had requested comments from interested parties on or before December 28, 2007. The primary focus in the MPUC's review was not to eliminate electric restructuring or return to vertically integrated electric utility monopolies, but rather to explore whether utilities should be allowed to own or have a financial interest in generation assets on a "regulated" basis to provide ratepayers a cost-of-service hedge against competitive electricity markets. The report notes that investor-owned utilities have taken the position before the MPUC that the restructuring law should be changed to allow them to own or have a financial interest in generation assets on a regulated basis. The report also notes that the generators, retail suppliers and the consumer-owned utilities commented in strong opposition to the re-entry of Maine's utilities into the generation business and that the Maine Public Advocate urges caution in considering whether utilities should be allowed back into the generation business, stating that the restructured market has protected customers from risks associated with the generation of electricity.

In its discussion, the MPUC explained that long-term contracts for energy and associated capacity can also provide ratepayer hedges against market fluctuations and stated that the MPUC had been directed by the legislature to develop a long-term resource adequacy plan and to conduct a competitive solicitation for long-term capacity and energy contracts. The MPUC noted that both long-term contract solutions as well as utility generation ownership come with similar new stranded costs risks, but stated that long-term contractual arrangements may be able to provide a hedge at an overall lower costs to ratepayers. The MPUC concluded that because of the risks to ratepayers and the potential for disruption of the competitive generation market, any decision to allow utility ownership of generation should be carefully considered. The MPUC stated that one means to limit ratepayer exposure is to place a cap on the amount of generation

capacity utilities are allowed to own (i.e., a capacity cap of a specified percentage of the demand within a utility's service territory). In addition, the MPUC noted that if the law were to allow utilities to own generation, a requirement to test all utility proposals through a competitive solicitation process is of utmost importance to minimize ratepayer costs and risks. The MPUC concluded that promotion of resource diversity is not a sufficient rationale on its own for utility ownership of generation assets.

The MPUC ultimately recommended against any immediate legislative changes that would allow state utilities to own or control generation assets. This recommendation was based, in part, on the fact that the legislature had already authorized the MPUC to direct utilities to enter into long-term contracts for capacity and associated energy. The MPUC stated that among other contracting approaches, it planned on seeking proposals from market participants that would provide ratepayers a cost-of-service hedge similar to that which would occur if a utility owned a generation asset on a regulated basis. The MPUC also noted that utilities have been out of the generation business for over seven years and, consequently, no longer have in-house generation expertise and may not be in a better position to develop and operate generation facilities than those market participants that are in the generation business. To the extent that the legislature decides to allow Maine utilities to re-enter the generation business, the MPUC recommended a limited approach that would, in general, place a cap on the amount of generation capacity that utilities are allowed to own, allow MPUC pre-approval, require proposals to be tested through a competitive solicitation process, grant MPUC authority over generation cost recovery, and require that energy and capacity from such assets be periodically sold into the wholesale market to avoid disrupting Maine's retail market.

10. New Hampshire Reports on Transmission Needs: The New Hampshire Public Utilities Commission ("NHPUC") "Background Report On New Hampshire Transmission Infrastructure"

The NH PUC prepared this report to cover, among other things, the current process for siting, constructing and financing transmission upgrades, the costs of potential transmission upgrades, and approaches pursued by other states to encourage transmission for renewable generation. The questions raised by the approaches suggested include who (public/private) should build upgrades and how to determine when they are required. How can the cost be allocated? Is the allocation of cost different depending upon the purpose, especially with respect to "location constrained" renewable resources? How to pay for building in "spare" capacity?

This report was focused on the northern New Hampshire 115kV system (the Coos County loop), but the issues raised may set the direction for several regional questions. Further, the NHPUC push to allocate at least some renewable related transmission into the PTF tariff (see ISO-NE Transmission study below) may ultimately affect all ISO-NE states, ratepayers, and new generators. The easy upgrade to the Coos County loop will cost \$10M to go from 60MW to 100MW (\$250/kW). Then, 3 major engineering projects were described to get up to 400-500MW total, costing \$160M-\$210M (\$400-\$700/kW), with costly varying inversely with siting flexibility.

The report outlines a potential process for planning and constructing new or upgrading existing transmission in the Coos County loop. This approach may be worth noting as a potential template for the NH will propose to the other ISO-NE states.

(a) Process

1. The initial upgrading of the system to accommodate incremental 40 Mws will be paid for by the first 40MW of projects in the Generator Interconnection Study Queue (the “Queue”).
2. One of the engineering options would be selected, based on lowest overall cost for all projects, with the 40MWs of projects held harmless to differential costs of the alternate solution. However, those differential costs will then be included in the overall (total) cost of upgrading the loop.
3. No matter when a generator actually connected into the new or upgraded transmission, they would pay their pro rated share of the total costs including costs for all required studies.
4. The cost of upgrading the existing loop and/or building the new transmission line would be paid by the generators who commit to build on a pro rata basis except for the first 40MWs of projects as described above. The cost of any desired surplus capacity would be borne by ratepayers. Possible funding sources were the RPS Alternative Compliance Payment funds and/or the sale of RGGI carbon allowances. The remaining, fall back, funding mechanism would be the electric rate payers of NH.

(b) Steps To Implement This Process

1. Could require legislation to allow use of RGGI sales revenues, allow utilities collect additional transmission fees, and to find that the approach is reasonable and prudent.
2. Possibly, a filing with FERC for a change to the existing tariff affecting NH would have to be made. This change would allow the connecting generators to be charged only their pro rata share of the total transmission costs (less the cost for any desired surplus transmission which would be paid by some combination of Alternative Compliance Payments under the RPS, RGGI funds, and a ratepayer assessment).
3. Perform the initial feasibility study for a predetermined amount of transmission capacity, i.e. estimated costs for upgrading to various capacities (e.g., 250 MW’s, 350 MW’s). These studies would be paid by the generators based on their pro rata share of the proposed new generation. At this point the only commitment the participating generators would have is to fund the study.

4. Then, the remaining steps of the System Impact and Facility Studies would be performed in the same manor with the generators paying for each step and determining if they wanted to continue in the process after the results were known.
5. In some manner, generator interest in funding their pro rata share of the actual transmission costs would have to be determined. Based on this and the amount of surplus capacity if any, that was desired; the amount of new capacity the new/upgraded transmission lines would be built to carry would be determined. Generators would then have to make a commitment with financial assurance to pay their pro rata share of the actual total costs not including the costs of any surplus.
6. The process of designing, permitting and building of the new and upgraded transmission would then begin.

(c) ISO-NE Regional Benefit Upgrades Study

The present FERC approved ISO-NE transmission tariff does not allow for pooling (or “socialization”) of the cost of upgrading transmission in a loop such as the Coos County loop. The Coos County loop, being a loop, provides no parallel capacity to the PTF and thus is not classified as PTF. Therefore, the NHPUC has been seeking the support of NECPUC for ISO New England to conduct a year long economic study of transmission to integrate new renewable electric generation, including, in particular, for northern New Hampshire. This study would develop a framework for transmission upgrades for new renewable electric generation resources, including imports from no- or low-carbon emission generation resources from outside New England, particularly Québec, *and to help determine whether or to what extent there is economic justification for including some or all of the cost of such transmission upgrades as “Regional Benefit Upgrades” as a part of the New England Transmission System Pooled Transmission Facilities (PTF)*. The report believes an agreement for a study among the ISO-NE states will be reached within a few months.

The NHPUC is looking to the results of the proposed ISO-NE economic study to provide the basis to allow upgrades to transmission such as those needed to allow the Coos County Loop to handle more capacity, to be reclassified as a Market Efficiency Transmission Upgrades (a type of Regional Benefit Upgrade which can be allocated). If the results support the pooling of transmission costs for new renewables, the resulting proposed tariff change will have to be vetted through the ISO-NE/NEPOOL stakeholder process and eventually approved by FERC. Bringing this option to fruition may be difficult but can be pursued in parallel with the New Hampshire only (non PTF) options.

(d) Summary of Other State/Regional Approaches

One paragraph summaries of approaches used by Texas, California, Colorado, Idaho and the Midwest ISO were included in section 4.

(i) **Texas** - the Texas PUC designates specific wind-rich zones as CREZ where wind developers issue a letter of credit of 10% of the project, and the costs are allocated 100% to ratepayers of the state.

(ii) **California** – Supplementary detail is in the 6 December PMC report. FERC issued a declaratory order approving a California ISO (CAISO) framework, noting that such resources are often renewable and have unique needs. In a nutshell, CAISO would roll in the costs of certain trunk facilities built to serve potential renewable generation, and then each generator would pick up its pro rata share of going-forward costs as they come on line. FERC noted that its order should serve as a signal of a policy shift for greater openness on generator interconnection, and *expressed an interest in adopting similar approaches in other regions*.

(iii) **Colorado** - In 2007, Colorado established a task force on renewable resource generation development areas to identify renewable resource developmental areas within Colorado.

(iv) **Idaho** - The Idaho PUC approved a negotiated settlement between wind developers and an Idaho utility (ID Power Co.) allowing wind developers to pay only 25% of transmission upgrades. The remaining 75% is recovered from ratepayers over 10 years.

(v) **Midwest Independent Transmission System Operator (Midwest ISO)**

FERC approved on Sept. 7, 2007 a new tariff revision to generator interconnection, whereby 100% of the upgrade costs resulting from the interconnection is recovered from the transmission end-users through two different cost allocation mechanisms. The new proposal is not restricted to renewable generation, but is expected that the proposal would encourage the development of renewable resources.