

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

Transmission Planning and Cost Allocation)
By Transmission Owning and Operating) **RM10-23-000**
Public Utilities)
)

**COMMENTS OF THE MAINE PUBLIC UTILITIES COMMISSION,
THE MAINE OFFICE OF THE PUBLIC ADVOCATE, THE MAINE
GOVERNOR'S OFFICE OF ENERGY INDEPENDENCE AND SECURITY, THE
NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION, ENVIRONMENT
NORTHEAST, AND CONSERVATION LAW FOUNDATION ON NOTICE OF
PROPOSED RULEMAKING**

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I. INTRODUCTION

The Maine Public Utilities Commission (“MPUC”), the Maine Office of Public Advocate (“OPA”), the Maine Governor’s Office of Energy Independence and Security (“OEIS”), the New Hampshire Public Utilities Commission (“NHPUC”) Environment Northeast (“ENE”) and Conservation Law Foundation (“CLF”) (collectively “Integrated Transmission Benefits Model Proponents” or “ITBM Proponents”) offer the following comments in response to the Commission’s June 17, 2010 Notice of Proposed Rulemaking regarding transmission planning and cost allocation in the above-captioned docket (“NOPR”).

The Commission’s NOPR identifies problems with current transmission planning and cost allocation methodologies and proposes solutions to address these problems. Some of the issues identified by the Commission are ones that have been of major concern to the MPUC for many years. Even prior to the issuance of the NOPR, the MPUC has been working with a consultant, London Economics International, L.L.C. (“London Economics”), to help it develop an alternative to ISO-NE’s current transmission planning and cost allocation methodologies that would better align transmission development and costs with economics and public policy, as well as reliability objectives. In particular, the alternative would facilitate transmission expansion to accommodate renewable resource development in-region, and would revise the cost allocation scheme so that costs are allocated roughly commensurate with benefits. The result of this effort is the development of the Integrated Transmission Benefits Model (“ITBM”). As discussed below, the ITBM addresses the following requirements proposed in the NOPR:

1. Local and regional transmission planning processes must explicitly provide for consideration of public policy requirements established by state or federal laws or regulations that may drive transmission needs.
2. Transmission planning and cost allocation must be more closely aligned.
3. Cost allocation methodology must result in the costs allocated to a beneficiary being roughly commensurate with the benefits that are expected to accrue to that entity.

Specifically, the ITBM addresses the following areas, discussed more fully below, in which ISO-NE does not meet the above-identified NOPR requirements: (1) The ISO-NE transmission tariff does not obligate ISO-NE to plan for transmission to meet public policy requirements (such as renewable resource portfolio standards (“RPS”)); (2) ISO-NE’s distinction between reliability and economic upgrades in practice results in the absence of any finding of need for Market Efficiency Transmission Upgrades, especially those that would provide access to renewables; and (3) ISO-NE socialization cost allocation methodology does not meet the requisite standard that the costs assigned must be reasonably commensurate with benefits derived. The ITBM, if adopted, would bring ISO-NE into compliance with the requirements proposed in the NOPR. Of critical importance, it will advance development of public policy transmission projects to access renewables to comply with state RPS mandates and it will allocate costs in a manner roughly commensurate with ratepayer benefits. The ITBM may also be suitable for regions to consider for interregional planning and cost allocation.

II. DEFICIENCIES IN NEW ENGLAND’S TRANSMISSION PLANNING AND COST ALLOCATION

A. Description of ISO-NE Transmission Planning and Cost Allocation Process

The ISO-NE Transmission, Markets and Services Tariff (“ISO-NE OATT”) identifies various categories of upgrades and assigns the applicable transmission cost allocation mechanism for each upgrade. Under the current methodology, two types of upgrades qualify as Regional Benefit Upgrades (“RBUs”) to receive cost recovery through regional rates.¹ To qualify as an RBU, a project must be included in ISO-NE’s Regional System Plan (“RSP”) as either a Reliability Transmission Upgrade (“RTU”) or a Market Efficiency Transmission Upgrade (“METU”). An RTU is defined as:

Those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of NERC and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.²

¹ In addition, upgrades below 115kV and those upgrades of 115kV or above that do not meet the tariff-specific criteria as Pool-Supported Transmission Facilities (PTF) are considered Local Benefit Upgrades with costs not allocated regionally. ISO-NE OATT Schedule 12 § 6.

² ISO-NE OATT I.1.2

METUs also qualify as RBUs. Specifically a METU is defined as:

Those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.³

As discussed in section II.B below, a METU has never been an approved part of the RSP.

Attachment N to the OATT contains additional information about the standards for identifying RTUs and METUs.⁴

Costs for RBUs that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is to be built are socialized, or "regionalized," which means simply that costs are allocated pro-rata across the region based on load share.⁵ Thus, the regional allocation of project costs appears to be based on an implicit assumption that various sub-regions benefit equally from the transmission upgrades.

The current cost allocation methodology also provides for Elective Transmission Upgrades, where the upgrade is participant funded (i.e., voluntarily funded by an entity or entities that have agreed to fund the costs of such upgrade). However, since the formation of ISO-NE, there have been no elective upgrades built within the ISO-NE region.

³ *Id.*

⁴ See ISO-NE OATT, Attachment N.

⁵ Costs in excess of these are "localized," which means that they are not included in the regional tariff. Localized cost determinations under Planning Procedure 4 do not constitute a determination of *project* beneficiary.

The ISO-NE OATT provides for a review and approval process to include transmission upgrades in the RSP. The tariff defines the purpose of the RSP as follows:

The purpose of the RSP is to identify system reliability and market efficiency needs and types of resources that may satisfy such needs so that Market Participants may provide efficient market solutions (e.g., demand-side projects, distributed generation and/or merchant transmission) to identified needs. The purpose of the RSP is also to assess the ability of proposed market solutions to address identified needs with due cognizance of the operational characteristics of those proposed market solutions and to identify a regulated transmission solution to be built by one or more PTO(s) in the event that market responses do not meet identified needs or that additional transmission infrastructure may be required to facilitate the market.⁶

B. Shortcomings in ISO-NE Transmission Planning and Cost Allocation

1. The Absence of an Obligation to Plan for Transmission to Meet Public Policy Requirements

FERC’s proposed rule would require each public utility transmission provider to amend its OATT such that its local and regional transmission planning processes explicitly provide for consideration of public policy requirements established by state or federal laws or regulations that may impact regional transmission needs. The Commission notes that currently “when choosing whether to include a proposed transmission project in its local or regional transmission plan, a public utility transmission provider has no explicit obligation under Order No. 890 or the *pro forma* OATT to evaluate the project based on its potential to facilitate the achievement of public policy requirements established by state or federal laws or regulations.”⁷ Without an explicit requirement that the public utility, transmission provider or RTO plan for public policy requirements such as for renewable development, there will be no way to end the

⁶ ISO-NE OATT Attachment K.

⁷ NOPR at P.58.

log jam that is obstructing access to renewables, and compliance with the long-term state-mandated renewable goals in New England will not be met.

The ITBM Proponents agree with the Commission that the RTO must consider transmission needed to allow public policy requirements to be achieved, including allowing access to renewable resources required to meet state RPS goals or other similar policy requirements. These factors should be considered by the RTO in identifying transmission for inclusion in the regional system plan. Unless this step is taken in New England, development of transmission needed to access in-region renewables is unlikely to move forward.

In ISO-NE, existing planning process and cost allocation provisions set forth in the current tariff are ill-equipped to deal with public policy imperatives designed to access greater renewable resources. Several studies have identified Maine and New Hampshire as the states in New England with the largest potential for renewable resource development, and current state energy policy is directed at moving aggressively to develop this potential⁸

Recent state and federal initiatives have emphasized a greater need to access additional renewable resources and displace fossil fuel generation. A review of the various New England states' renewable portfolio goals reveals that New England intends to access 17,251 GWh of renewables by 2020. RSP09 table 7-8. A March 2008 Report by Levitan & Associates revealed that the New England region has available on-

⁸ Maine alone has set a goal of three thousand megawatts of wind resources by 2020. See 35-A M.R.S.A. § 3404(2)(B) (The goals for wind energy development in the State are that there be ... [a]t least 3,000 megawatts of installed capacity by 2020, including 300 megawatts or more from generation facilities located in coastal waters"); See Bill Henson, Senior Engineer, Renewable Resource Integration, ISO-New England, *New England Wind Integration Study (NEWIS) Wind Scenarios and Transmission Overlays*, June 21, 2010, Planning Advisory Committee Meeting Materials, slides 11-16. Power Point Presentation available online at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/jan212010/newis.pdf

shore capacity of more than 47,000 megawatts in available renewable Class I and II resources, with nearly 27,000 megawatts available in Maine alone.⁹ Because Northern New England renewable resources are remote from load centers, transmission is necessary to access these renewables.

The New England States' ambitious renewable goals will be realized only if transmission planning and cost allocation regimes are aligned with these goals.¹⁰ As noted above, there is no existing mechanism to require that the RSP include transmission upgrades needed to meet New England's renewable portfolio requirements. Accordingly, direction from the Commission is needed so that ISO-NE and stakeholders are required to develop tariff language to require consideration of these goals as part of the needs determination in the RSP.

The ITBM Proponents anticipate that some commenters will argue that economic upgrades should be left to private transactions and merchant facilities. While it is true that development of merchant transmission lines is one tool available to parties, it is doubtful that regional and national renewable energy goals can be achieved solely through voluntary private agreements. Individual regions need (and currently do not have) adequate planning processes that can properly evaluate economic projects and projects that are driven by public policy directives to access renewable energy. In New

⁹ See ISO-New England, Levitan & Associates, Phase II Wind Study, March 2008, at 17. Document available online at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2008/may202008/lai_5-20-08.pdf

¹⁰ See, e.g. Draft Decision, DPUC Review of the 2010 Integrated Resource Plan, Connecticut Department of Public Utility Control at 63-64 (discussing findings in the Connecticut Energy Advisory Board) that an additional \$10 billion investment in transmission would be needed to meet Connecticut and regional 2020 renewable requirements). This Draft Decision can be accessed at the following link: [http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/38c7e3c6eb889bc38525778b0067c098/\\$FILE/df100207.doc](http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/38c7e3c6eb889bc38525778b0067c098/$FILE/df100207.doc)

England, while the concept of a participant funded transmission line to access renewables has been approved by the Commission,¹¹ the concept has not yet resulted in any proposed participant funded transmission line in the RSP. Thus, this conceptual proposal does not counter the Commission's concern that participant funding *cannot* be the only route to getting transmission built to accommodate state renewable and other similar policy state policy requirements. Instead, the Commission's concern that there needs to be a way to move forward transmission projects to access renewables suggests that there must be a requirement that the transmission plan includes transmission needed to allow public policy requirements such as renewables procurement (or to advance similar state or federal public policy).

2. The False Distinction Between Reliability and Market Efficiency Upgrades is Not Conducive to the Development of Efficiency Projects Especially Those That Provide Economic Benefits and Provide Access to Renewable Resources.

In the ISO-NE region, the distinction between reliability and market efficiency upgrades has impeded the development of transmission that may not be needed strictly for reliability reasons but which would reduce congestion costs and provide greater access to low-cost supply, including renewables in locations remote from load centers. The NOPR does not require the elimination of distinctions between reliability and economic projects; however, the recommendation from MPUC's consultants and from other economic and policy experts suggest that a stronger stand on disparate treatment of reliability and economic upgrades may be appropriate. For example, a white paper issued by panel of industry experts stated:

¹¹ See, e.g., *Northeast Utilities Service Co. and NSTAR Electric Co.*, 127 FERC ¶ 61,179 (2009) (May 22 Order); Rehearing Denied, *Northeast Utilities Service Co. and NSTAR Electric Co.*, 129 FERC 61,279 (2009).

Conceptually, the problem with distinguishing between “reliability upgrades” and “economic upgrades” is that it injects an artificial dividing line between two things that are both fundamentally economic concepts. The distinction assumes that a new, or otherwise unexploited, supply option falls into the domain of something “economic,” whereas every new increment of demand is not associated with an economic assessment. In other words, this conceptual framework treats every net increase in load—whether from a new appliance from an existing customer or a new home or factory or hospital constructed within a local system—as a fixed electrical requirement that must be met for reliability purposes and not for economic purposes. However, it is just as appropriate to think about incremental demand—again, conceptually—as something that has the option of being served economically, or not. To make the point more vividly, it might not be “economical” to meet the reliability-related requirements of incremental load by adding transmission upgrades when the reliability problem could be satisfied at lower cost through, say, locationally targeted demand response, optimally distributed generation, or other means of assuring reliable electric service to both existing and incremental loads. The focus in “reliability” upgrades on a fixed forecast demand ignores price-responsiveness of demand and the value to consumers of incremental demand.

Another practical difficulty with traditional distinctions between “reliability” and “economic” upgrades is the fact that almost all transmission projects in effect serve both purposes. At any point in time—and even more so over time—almost any project will lower the risk of interruptions by some degree, and almost every upgrade justified for reliability concerns will inevitably yield at least some economic benefits as well.¹²

This white paper also points out that it is easier to overcome opposition to a reliability upgrade by “appeal to the implicit bogeyman of blackouts as the main justification for construction of transmission facilities.” *Id.* at 16.

In New England, the effect of this false distinction is that to date

(1) only reliability upgrades have been approved and constructed and (2) many projects

¹² A National Perspective on Allocating the Costs of New Transmission Investment: Practice and Principles, A White Paper Prepared by the Blue Ribbon Panel on Cost Allocation for WIRES, the Working group on Investment in Reliable and Economic electric Service (2007) (“WIRES White Paper”) at 14-15. The WIRES White Paper can be accessed at the following link: http://www.hks.harvard.edu/hepg/Papers/Rapp_5-07_v4.pdf.

justified as reliability upgrades have, in fact, resulted in significant economic benefits within certain subregions.

Since ISO-NE's inception, only one METU has been studied as part of the regional planning process. This project, known as the Maine Power Connection ("MPC") would have allowed delivery of nearly 800 megawatts of Maine wind generation to the New England market. The MPC encountered significant resistance, and, while the provision for socializing the cost of METU projects was never legally challenged because the wind developer withdrew its funding for the interconnection study process, the significant opposition to the MPC project and ISO-NE's reluctance to defend the provisions of Attachment N relating to METU projects have likely been significant factors in the absence of any further METU proposals or findings of need by ISO-NE for METU projects. In fact, ISO-NE indicates in its most recent draft RSP that there is no foreseeable need for METUs due to the decrease in congestion from extensive reliability transmission upgrades, as well as new supply and demand side resources in the region.¹³

In fact, as will be further detailed below, recent market monitor reports and other documents indicate that many recent "reliability" projects have resulted in significant economic improvements such as relieving congestion and eliminating the need for congestion revenue and financial transmission rights. The fact that identified "reliability" needs result in transmission solutions that produce significant economic benefits to various subregions provides additional support for eliminating the distinction

¹³ *ISO-New England Inc., System Planning, Third Draft 2010 Regional System Plan, September 8, 2010 ("2010 Draft Regional System Plan")* at 88. ISO-NE is incorrect in suggesting that METUs are appropriate only for congestion cost reduction. A METU can address load costs such as energy, capacity, reserves, losses, impacts on bilateral prices for electricity, as well as other costs to load. ISO-NE OATT I.1.2.

between “economic” and “reliability” upgrades, especially where such distinctions lead to disparate treatment. In addition, as discussed in Section II.B.3 below, the fact that reliability upgrades produce significant economic benefits to specific subregions militates in favor of a beneficiaries pay cost allocation such as that proposed in the ITBM.

3. Current Allocation Methods for Transmission May Not Be Just and Reasonable Because They May Inhibit the Development of Efficient, Cost-Effective Transmission Facilities and Do Not Comply With the Requirement That Costs Assigned Must be Roughly Commensurate With Benefits Derived.

The NOPR outlines the Commission’s concerns with existing cost allocation methodologies to the extent that (1) the cost allocation scheme may impede the development of needed transmission or (2) it may allocate costs in a manner that is not roughly commensurate with benefits (which can also lead to delays in transmission construction). The Commission states with respect to “projects that affect multiple utilities’ transmission systems and therefore may have multiple beneficiaries,”

With respect to such projects, any individual beneficiary has an incentive to defer investment in the hopes that other beneficiaries will value the project enough to fund its development. On one hand, a cost allocation method that relies exclusively on a participant funding approach, without respect to other beneficiaries of a transmission facility, increases this incentive and, in turn, the likelihood that needed transmission facilities will not be constructed in a timely manner. On the other hand, if costs are allocated to entities that will receive no benefit from a transmission facility, then those entities are more likely to oppose inclusion of the facility in a regional transmission plan or to otherwise impose obstacles that delay or prevent the facility’s construction.¹⁴

In New England, both problems are apparent. As noted above, neither METU nor participant-funded projects that would have resulted in both economic

¹⁴ NOPR at P. 153.

benefits and access to renewables have been built or even included in the RSP. Without planning and cost allocation regimes that properly recognize these benefits and allocate costs accordingly, such projects will remain difficult or impossible to develop. As discussed above, ISO-NE has not yet found a need for METU projects such as the MPC project. Any new project that might be justified by dual economic benefits such as meeting RPS requirements and reducing congestion costs will be opposed in the hope that some other group of ratepayers will value the project enough to pay for it (*e.g.*, through participant funding). However the Commission has specifically rejected exclusive reliance on participant funded approaches.¹⁵ As discussed above, reliance on a participant funded approach has not resulted in transmission projects to access remote wind generation potential in northern New England, even though these renewables and transmission to access them are likely to cost significantly less than the massive transmission build out that would be necessary to access distant wind resources in the Midwest.

On the other hand, when economic projects are repackaged as reliability projects and costs are allocated by simple load-share, there will be opposition to inclusion of these projects in the plan where the benefits of the project to some ratepayers are not roughly commensurate with the costs being assessed to those ratepayers. As discussed below, the economic benefits of many of the “reliability projects” have inured to the benefit of specific subregions in much greater proportion than to the region as a whole.

¹⁵ See *id.* P.168 (“[a] cost allocation method that relies exclusively on a participant funding approach without respect to other beneficiaries of a transmission facility, exacerbates the free rider problem that the Commission identified in Order No. 890...[and] such a cost allocation would not satisfy the proposed principles.”).

One example of disproportionate benefits of the cost allocation in New England is shown in examining the benefits of Phase I of the Southwest Connecticut project. Following construction of Phase I, congestion into Norwalk-Stamford and Southwest Connecticut decreased considerably. In 2007, ISO-NE's External Market Monitor concluded the following:

Congestion into Norwalk-Stamford declined significantly from 2006-2007, which is the most notable change shown in the figure. The average congestion price difference between the New England Hub and Norwalk-Stamford decreased from more than \$25 per MWh in 2006 to less than \$5 per MWh in 2007. The reduction in congestion in the summer months was even more substantial: the average congestion price difference decreased from more than \$60 per MWh during the summer of 2006 to \$7 per MWh in 2007.

Two factors explain the dramatic reduction in congestion into Norwalk-Stamford. First, Phase I of the Southwest Connecticut 345 kV Transmission Project was completed in October 2006. The additional transmission capability reduced the need to dispatch expensive resources in Norwalk-Stamford. Second, the Peaking Unit Safe Harbor ("PUSH") offer rules expired in June 2007, leading to lower offer prices for supplies in Norwalk-Stamford. The PUSH offer rules allowed owners of low capacity-factor generators in Designated Congestion Areas to include levelized fixed costs in energy offers without risk of mitigation. Since the expiration of the PUSH program in June 2007, some of the affected units have entered into Reliability Agreements with the ISO that require the units to submit offers equal to marginal cost.

See David B. Patton, Pallas LeeVanSchaick, Potomac Economics, Ltd., Independent Market Monitoring Unit, 2007 Assessments of the Electricity Markets In New England, June 2008 ("2007 External Market Monitor Report") at 23-24. In spite of the benefits accruing to Southwest Connecticut, the costs of the project (net of costs that were determined to be in excess of those required to constitute good utility practice, such as the incremental cost of undergrounding lines due to siting board requirements) were

allocated on a pro-rata basis as though all of the sub-regions benefited roughly equally from the project.

Recently built “reliability” projects in New England’s major load centers in Massachusetts and Connecticut continue to bring significant economic benefits to these load centers. ISO-NE’s Internal Market Monitor recently concluded that new transmission projects had resulted in significant decreases in congestion. In fact, in 2009, the Congestion Relief Fund was less than one quarter of the required fund in 2008. The Internal Market Monitor stated:

In 2009, the value of the congestion fund was \$25.1 million, and the sum of day-ahead and real-time loss charges was \$34.3 million. In 2008, the value of the congestion fund was \$121 million, and the total marginal loss fund was \$98 million. The congestion fund in 2009 represented just 0.5% of the energy market value in 2009. The reduction in the value of the congestion fund was caused by a reduction in the amount of congestion on the system due to the completion of new transmission and a reduction in the cost of congestion caused by lower LMPs.

See ISO-New England, Internal Market Monitor, *2009 Annual Markets Report*, May 18, 2010 (“2009 Internal Market Monitor Report”) at 10.¹⁶ The External Market Monitor made similar findings in its own recent evaluation of the New England markets:

Transmission upgrades completed in 2009 significantly reduced congestion into Lower SEMA and Connecticut. In the day-ahead market, the average congestion-related price difference between the New England Hub and Lower SEMA fell from \$10.10 per MWh in 2008 to \$0.96 per MWh in 2009. Likewise, the average congestion price difference between the New England Hub and Norwalk-Stamford fell from \$4.79 per MWh in 2008 to \$0.72 per MWh in 2009. In addition to the transmission upgrades, the sharp reduction in natural gas prices also contributed to lower congestion since redispatch costs are generally highly correlated with fuel prices.

¹⁶ Document available online at: http://www.iso-ne.com/markets/mktmonmit/rpts/other/amr09_final_051810.pdf

See David B. Patton, Pallas LeeVanSchaick, Potomac Economics, Ltd., Independent Market Monitoring Unit, *2009 Assessments of the Electricity Markets In New England*, June 2010 (“2009 External Market Monitor Report”) at xii.

These examples demonstrate that the current cost allocation does not comply with the requirement that costs assigned *must be roughly commensurate with benefits derived*.¹⁷ The recent decision of the Seventh Circuit Court of Appeals in *Illinois Commerce Commission v. FERC*¹⁸ makes clear that “FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation the costs sought to be shifted to others.”¹⁸ *Illinois Commerce Commission* also makes clear that simply pointing to possible reliability benefits or concern about difficulty of determining benefits is not sufficient to support a socialized cost methodology. The Seventh Circuit rejected, as insufficient, a purported justification for socializing costs of upgrades of 500kV or greater on the grounds that the such large transmission lines provide a general reliability benefit to the whole region:

That leaves for consideration the benefits that the Midwestern utilities might derive from the greater reliability that the larger-capacity transmission facilities might confer on the network as a whole. The reason for building such facilities is to satisfy the demand of eastern consumers for electricity, but the more transmission capacity there is, the less likely are blackouts or brownouts caused by surges of demand for electricity on hot summer days or by accidents that shut down a part of the electrical grid. Because the transmission lines in PJM’s service region are interconnected, a failure in one part of the region can affect the supply of electricity in other parts of the network. So utilities and their customers in the western part of the region could benefit from higher-voltage transmission lines in the east, but nothing in

¹⁷ 576 F.3d 470 (7th Cir. 2009).

¹⁸ *Illinois Commerce Comm’n v. FERC*, 576 F.3d at 476.

FERC's opinion in this case enables even the roughest ballpark estimates of those benefits.

Illinois Commerce Commission, 576 F.2d at 476. While the Seventh Circuit made clear that exacting precision in determining costs and benefits was not required for a cost allocation mechanism to survive appellate review, it concluded that FERC could not use a presumption that new transmission lines benefit the entire network by reducing the likelihood or severity of outages "to avoid the duty of comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party." *Id.* at 477.

The 2004 Commission decisions approving New England's current cost allocation methodology do not insulate the methodology from an examination whether it meets the standards outlined in *Illinois Commerce Commission*. The Commission's approval of the scheme not only predated *Illinois Commerce Commission*, but also could not foresee the extent of the imbalance of cost allocation to benefits derived as is evident today.

The ITBM as outlined below would go far in eliminating the shortcomings discussed above with ISO-NE's planning and cost allocation methodology. Specifically, as discussed below, the ITBM would help to eliminate barriers to construction of new transmission to access renewables and would establish a more economically efficient and equitable method of allocating costs, consistent with the requirements of *Illinois Commerce Commission*, for all types of transmission upgrades.

III. INTEGRATED TRANSMISSION BENEFITS MODEL

A. Description of the Integrated Transmission Benefits Model

The ITBM rests on the following core principles:

- Transmission projects often provide a blend of reliability, economic and public policy benefits and therefore should not be strictly categorized as one or the other.
- Transmission planning and cost allocation should be based on benefits to consumers, including reliability, economic and public policy benefits.
- Transmission costs should be allocated roughly in proportion to the benefits to consumers.

The manner in which these principles are woven into the model is described below.

1. Integrated Transmission Planning

The ITBM model eliminates false distinctions in transmission planning between reliability and economic upgrades. Instead, the ITBM model is based on the principle that modern day transmission projects yield both reliability and economic benefits and thus should not be classified solely as either a reliability or economic upgrade.

All projects with positive net economic benefits (measured as described below) should be included in the transmission plan. In addition, two categories of projects with negative net economic benefits should be included as well. First, it is possible that a project that is needed to comply with reliability standards will have negative economic benefits. However, if the project is needed to comply with federal reliability standards, it should be included in the plan. Second, it is possible that a project that is needed to meet state renewable requirements will have negative net benefits when benefits are measured in terms of energy market prices. However, where a project is required to allow a state renewable policy requirement to be met, there should be a

method for consideration of and inclusion in the plan (subject to certain limits discussed in section III(A)(3) below).

In the context of the ITBM, net economic benefits are measured in terms of the net present value (“NPV”) change in electricity supply costs to load¹⁹ resulting from the transmission project, compared to the NPV cost to load of the transmission project. When the reduction in electricity supply costs exceeds the cost of transmission, the project is deemed to have positive net economic benefits.

2. Benefits Determination

Although Attachment N to the ISO-NE OATT uses production cost to determine net benefits, the MPUC believes that benefits should be measured in terms of the relevant costs to load rather than on production costs or a mix of production costs and energy charges. The rationale for this view, recommended by MPUC’s consultant, London Economics, is based on the view that the purpose of transmission is to eliminate constraints to the buying and selling of electricity, and the charge to load best represents such transactions. In addition, at least in the United States, it is load that pays for transmission²⁰ and, thus, in order to allocate costs commensurately, the benefits should also be measured on the basis of costs that are relevant to load. In New England, these are driven largely by the locational marginal prices (“LMP”) in the ISO-NE wholesale energy market. Production costs, on the other hand, reflect to costs of the generators and will not provide a relevant measurement of the effect on load of the transaction.

¹⁹ This may include changes in energy, capacity or ancillary service charges, as well as renewable energy credits.

²⁰ One exception is that generators pay for the cost of generator interconnection transmission facilities.

In New England, several entities in the Economic Studies Working Group suggested revising Attachment N to use a congestion cost metric rather than a production cost metric to determine whether a project was eligible as a Market Efficiency Transmission Upgrade. For example, the Massachusetts Attorney General's office stated:

One central concern is that the production cost metric that ISO New England proposes to apply may lead to the imposition of new transmission costs that will be unjust and unreasonable. A production cost metric may be reasonable for a vertically integrated transmission provider to apply to reduce the costs of serving native load, because those production cost savings are passed through to end users. In the current New England market structure, however, it is inappropriate for ISO New England to rely on a production cost metric, because the cost of new transmission proposed under Attachment N may be borne by load serving entities ("LSE") and their customers, but production cost savings will inure to certain generation developers, and end users may not benefit through lower energy costs.²¹

Similarly, the benefit metric can include the cost of compliance with renewable portfolio requirements and other environmental requirements the states have in common as long as the methodology for determining these benefits is set forth in the applicable tariff. The development and application of these metrics would be fleshed out during the compliance phase of the NOPR.

3. Certain Projects that Do Not Have Net Economic Benefits Are Included in the Plan

While the ITBM is focused on identifying the economic benefits of projects, there may be reliability or public policy projects that should be included in the plan that do not have net economic benefits. If a project is needed to comply with federal

²¹ August 21, 2008 letter from Jesse Reyes of the Massachusetts Office of the Attorney General to Robert Eithier, Vice President of Market Development of ISO-NE, which can be accessed at the following link: http://www.iso-ne.com/committees/comm_wkgrps/othr/econ_stdy/mtrls/2008/aug222008/index.html.

reliability requirements, it should be included in the regional plan. This is consistent with the status quo. In addition, a project that is needed to allow public policy requirements to be met, such as renewable portfolio requirements, should also be included in the plan for the reasons outlined in the NOPR:

First, increasing transmission capability will help ensure a reliable electric supply and provide greater access to economically priced power. Second, the growth in renewable energy development, stimulated in part by state-adopted renewable portfolio standards (RPS) and the possibility of a national RPS, will require significant new transmission to bring these resources, which are often remotely located, to consumer load centers.” The number of states that have adopted renewable portfolio standard measures, as well as the target levels set in those measures, has continued to increase. Some 30 states and the District of Columbia have now adopted renewable portfolio standard measures. These measures typically require that a certain percentage of energy sales (MWh) or installed capacity (MW) come from renewable energy resources, with the target level and qualifying resources varying among the renewable portfolio standard measures.

In its role as the Commission-designated Electric Reliability Organization, the North American Electric Reliability Corporation (NERC) concluded that significant transmission expansion will be needed to comply with renewable mandates. Even in the absence of a national renewable portfolio standard, NERC has stated that “an analysis of the past 14 years shows that the siting and construction of transmission lines will need to significantly accelerate to maintain reliability over the coming years.” In its 2009 assessment of transmission needs, NERC found that if a national renewable portfolio standard of 15 percent were adopted, an additional 40,000 miles of transmission lines would be needed and “transmission would be a key component to accommodating new resources, linking geographically remote generation to demand centers.”²²

We do not mean by this to suggest that projects satisfying only a single state’s public policy goals,²³ or even multiple states’ public policy goals should be pursued without

²² NOPR at PP. 29-31 (citations omitted).

²³ For example, a single state siting requirement that increases project costs for purely local benefit would not qualify as an eligible public policy requirement.

regard to cost. Rather, the regional planning process should be a tool to examine how to collectively satisfy regional needs as economically and efficiently as possible, minimizing the amount of infrastructure required to do so. In addition, many New England states have included as part of their public policies on renewable requirements “Alternative Compliance Penalties,” which serve as defacto caps on the price their consumers will pay for renewable energy. This element of public policy should also be included in the planning process and may limit the number of negative net benefit public policy transmission projects ultimately included in the plan.

4. Cost Allocation

Under the Seventh Circuit Decision in *Illinois Commerce Commission*, costs of transmission must be allocated in a manner roughly commensurate with the benefits of the transmission. The ITBM allocates costs in such a manner. As mentioned above, the current New England transmission tariff already provides a two part mechanism which enables transmission costs to be recovered either regionally or locally. The tariff could be readily modified to implement the ITBM in which project costs will be recovered to the extent possible from direct beneficiaries in one part of the rate with the remainder of project costs recovered in the second. Moreover, since the benefits determination is done at the transmission planning stage, there will already be a determination of how project costs will be allocated to the customers of transmission owners.

a. How the ITBM Allocates Costs

There are various cost/benefit scenarios that arise as a result of transmission projects. A project can result in either net positive or net negative

economic benefits for region in the aggregate, as well as for individual zones within the region. The ITBM provides a suitable framework for these varied scenarios, as illustrated in the hypothetical cases below:

1. Case 1: Net Economic Benefits – All Zones Benefit; None harmed

Case 1 illustrates a transmission project with net economic benefits in which reductions in the present value of the energy costs to consumers in the entire region (comprised of three zones) exceeds the present value cost of the transmission project. Additionally, the energy costs in each of the three zones are reduced by the transmission project. Because energy cost reductions exceed the transmission project costs, 100% of the project costs can be allocated based on economic benefits. In the example provided, one can see that zones A, B, and C are allocated transmission project costs in direct proportion to the energy cost reductions received by the zone, and each receives the same proportional share in the net benefits generated.

Case 1 - Transmission project results in overall net benefit; energy benefit in all Zones												
Transmission Project Direct Cost				\$100								
Transmission Project Indirect Cost				\$0	<i>(Zone "make-whole" cost)</i>							
Energy Cost Increase/(Decrease)				(\$150)								
T Allocated per Energy Benefit				\$100								
T Allocated per Pro-rata Load Share				\$0								
	Energy Cost Increase/(Decrease)				T Costs Allocated per Energy Benefit				Net Cost/(Benefit)			
	Zone A	Zone B	Zone C	Total	Zone A	Zone B	Zone C	Total	Zone A	Zone B	Zone C	Total
Energy decrease	(\$100)	(\$40)	(\$10)	(\$150)	\$67	\$27	\$7	\$100	(\$33)	(\$13)	(\$3)	(\$50)
Energy increase	\$0	\$0	\$0	\$0	\$-0	\$-0	\$-0	\$0	\$0	\$0	\$0	\$0
Net Total	(\$100)	(\$40)	(\$10)	(\$150)	\$67	\$27	\$7	\$100	(\$33)	(\$13)	(\$3)	(\$50)

2. Case 2: Net Economic Benefit – One Sub-Region Harmed

Case 2 is an example of a transmission project that provides net economic benefits for the region, but which causes the energy costs for one

monitor reports issued subsequent to when projects were placed in service.

Implementation of the ITBM would require a consistent application of the assumptions to be used in the economic analysis prior to project approval. Under the ITBM, these assumptions would be established in the tariff or manuals after vetting through the stakeholder process.

**i. Southwest Connecticut Phase I
Transmission Project (Bethel to Norwalk)**

Phase I of the Southwest Connecticut Power

Reliability Project (“SWCT Phase I”) is an example of a reliability project that does not yield net economic benefit region-wide, but does have a marked effect on energy costs sub-regionally. As such, project costs could have been more appropriately allocated based on the ITBM’s blended economic benefits allocation formula rather than the current New England pro-rata allocation. The total cost of the project was \$354.8 million dollars, of which ISO New England determined that \$239.8 should be recovered through the Regional Network System (“RNS”) rate.²⁴

Connecticut Light and Power Co. (“CL&P”)

designed the project to address primarily reliability problems in Southwest Connecticut (“SWCT”). CL&P stated in support of the project, “The transmission system in SWCT is presently exposed to line overloads, voltage degradations and high short-circuit currents under various operating conditions. As a result, there is an increasing risk of customer outages in the SWCT region, particularly in the Norwalk-Stamford Sub-area.”²⁵ However,

²⁴ In ISO-NE’s finding, \$2.4 million was determined not to be eligible for pool support due to its definition as non- Pool Transmission Facility (“PTF”), and \$117.4 million of the project costs were determined to have been driven by local design standards and not suitable for regional recovery.

²⁵ Bethel to Norwalk 12C Application to ISO-NE dated January 12, 2005 at 3.

CL& P promoted the economic advantages of the project as well, stating that the specific objectives of this project are to:

- Reliably increase capacity to a transmission-constrained area, responding to southwestern Connecticut's demands for electric power,
- Reduce existing transmission congestion and related costs which exceeded \$25 million in the year 2000 in the Connecticut sub-region of the New England Power Pool (NEPOOL), and which are expected to grow significantly in the next few years absent new power supply to the area,
- Provide greater access to competitively priced generation, and
- Accomplish these objectives by a means that strikes the appropriate balance between the lowest reasonable cost to consumers and the lowest reasonable environmental impact.²⁶

While no formal economic analysis of project economic benefits was conducted, the External Market Monitor made clear in a 2006 report that a large fraction of the observed congestion in the pool was due to transmission constraints into the Norwalk-Stamford load pocket. “Imports to the Norwalk-Stamford load pocket accounted for approximately 60 percent of the net congestion revenues collected by the ISO from the day-ahead and real-time markets in 2006.”²⁷

After the SWCT Phase I improvements were placed in service, the level of observed congestion in the pool was seen to drop dramatically.

Net congestion revenue dropped from \$180 million in 2006 to \$112 million in 2007, while net target payments to FTR holders fell from \$175 million in 2006 to \$122 million in 2007.

Congestion decreased primarily due to the transmission additions in Southwest Connecticut placed in service in October 2006 and the expiration of PUSH bidding rules in June 2007, which both reduced congestion into Norwalk-Stamford.²⁸

²⁶ CL&P application to Connecticut Siting Council at 1-2. This document can be accessed at the following link: http://www.ct.gov/csc/lib/csc/docket217/docket_217_application_vol_1.pdf.

²⁷ David B. Patton, Pallas LeeVanSchaick, Potomac Economics, Ltd., Independent Market Monitoring Unit, *2006 Assessment of the Electricity Markets In New England*, June 2007 (“2007 External Market Monitor Report”) at 6.

²⁸ See 2007 External Market Monitor Report at 44-45.

Using the 60 percent figure discussed above, the SWCT Phase I increased transfers provided a \$40.8 million (per year) energy cost benefit to load in the region. The present value of the annual \$40.8 million dollar congestion relief calculated at a 13% discount rate is \$221.3 million dollars compared to the \$239 million project cost ruled eligible for regional cost recovery.²⁹ This project, therefore, does not yield net economic benefits to the region. Because it is needed for reliability, however, under the ITBM, the rest of the region would pay its pro-rata share of the non-economic costs (in this case \$239 - \$221.3 = \$17.7 million). Consumers in the load pocket would in this circumstance pay for their pro-rata share of the project and contribute up to the economic value they receive in reduced energy expense. Table 1, below, provides a hypothetical illustration of how the costs of the SWCT Phase I project might have been allocated under the ITBM compared to the way they were actually allocated under the existing tariff.

Table 1 SWCT Phase I
Cost allocation under Current Methodology and ITBM

Local Networks	RNS (\$000)	ITBM (\$000)	Difference (\$000)
NSTAR	\$49,623	\$3,810	- \$45,813
BHE	\$3,129	\$240	- \$2,889
Fitchburg G&E	\$908	\$70	- \$838
CMP	\$16,976	\$1,303	- \$15,673
Grid	\$67,007	\$5,144	- \$61,863
NU	\$83,521	\$227,803	\$144,281
UI	\$8,592	\$660	- \$7,933
Vtransco	\$10,043	\$771	- \$9,272
<i>Totals</i>	<i>\$239,800</i>	<i>\$239,800</i>	

²⁹ In this example, we assumed a ten year stream of savings which is the same as the time span covered by ISO-NE's annual Regional System Plan.

ii. Maine Power Reliability Project

Central Maine Power Company's ("CMP") Maine Power Reliability Program ("MPRP"), recently approved by the MPUC, provides an example of a reliability project that yields net economic benefits, and whose costs could more appropriately have been allocated based on the ITBM's beneficiaries pay cost allocation.

While ISO-NE and CMP witnesses testified to the reliability need for the project in the MPUC Certificate of Need and Public Convenience ("CPCN") proceeding, CMP also submitted expert testimony from LaCapra Associates ("LaCapra") assessing non-transmission alternatives to the MPRP. LaCapra explains that "[t]he entire New England region stands to realize considerable economic benefits from constructing the MPRP from increased transfer capability. The regional benefits, which only measured changes in total energy costs, exceed the total cost of the MPRP by a significant margin."³⁰ In its analysis of regional economic benefit, LaCapra examined the energy pricing benefits to New England load by multiplying hourly loads by hourly LMPs in the load zones in other New England states. LMPs were estimated using LaCapra's PROSYM model.³¹ LaCapra concluded, "The NPV (2008\$) energy costs for costs in the rest of New England under Alternative Resource Configuration I are \$1,695

³⁰ See Petition by Central Maine Power for Finding of Public Convenience & Necessity for the Maine Power Reliability Program Consisting of the Construction of Approximately 350 Miles of 345 kV and 115 kV Transmission Lines, MPUC Docket No. 2008-255, Petition and Initial Filing, July 1, 2008 ("MPRP CPCN Filing") Volume IX, Exhibit I-3 ("LaCapra Associates Non Transmissions Alternatives Assessment") at 9.

³¹ As noted above, these examples are for illustrative purposes only, and the reference to the LaCapra model is not an endorsement of this or any other model for determining LMP changes. The point of the illustration is that the models exist already for projecting LMP changes. In the compliance process, there will be opportunities through the stakeholder process to determine the most appropriate models and analyses for determining economic benefits.

million higher than for the transmission upgrades identified by the MPRP ... these savings estimates are for the five New England states excluding Maine. These savings are driven by the lower LMPs produced by the transmission upgrades identified by MPRP, compared to the non-transmission alternatives.”³²

According to the LaCapra analysis, the MPRP project is a reliability project that has net economic benefits of \$680 million³³ over the study period and a benefit to cost ratio of 1.67 to 1. The majority of the price benefit is experienced outside of Maine, while the price advantage to Maine’s load from MPRP is essentially neutral.³⁴

As seen in Table 2 below, under the ITBM allocation formula, none of the project costs for the MPRP would be allocated to Maine load. Instead, the cost of the project would be recovered from other consumers in the pool through their local network service rates in accord with the relative benefits in price received.³⁵

³² LaCapra Associates Non Transmissions Alternatives Assessment at 138.

³³ *Id.* at 135. (\$1,695 million – \$1,015 million = \$680 million).

³⁴ Maine load is essentially neutral over the study period. Maine load pays lower LMPs for the early half of the study period and higher LMPs for the second half of the study period with MPRP in place compared to non-transmission alternatives. See MPRP CPCN Filing, Volume IX, Exhibit 1-3 (redacted) at P. 148.

³⁵ Although calculated by LaCapra, the values for each utility in the pool were not provided in the report. In this example, we assumed a pro-rata distribution of the benefit.

Table 2 MPRP
Cost allocation under Current Methodology and ITBM

Local Networks	RNS (\$000)	ITBM (\$000)	Difference (\$000)
NSTAR	\$280,190	\$305,831	\$25,642
BHE	\$17,670	\$0	-\$17,670
Fitchburg G&E	\$5,125	\$5,594	\$469
CMP	\$95,852	\$0	-\$95,852
Grid	\$378,348	\$412,972	\$34,624
NU	\$471,591	\$514,749	\$43,158
UI	\$48,515	\$52,955	\$4,440
Vtransco	\$56,709	\$61,899	\$5,190
TOTAL	\$1,354,000	\$1,354,000	

iii. Maine Power Connection

The MPC provides an example of a project whose cost could be allocated using the ITBM allocation formula. The MPC was a proposed transmission project that would have interconnected the transmission system of Maine Public Service (“MPS”) with the rest of New England.³⁶ The MPC was proposed as a Market Efficiency Transmission Upgrade (“METU”) under Attachment N of the transmission tariff. The project included the construction of new 345 kV transmission facilities that would have provided New England with access to significant sources of low-cost energy. The project was also consistent with public policy requirements since it would also have provided access to 800 MW of wind resources into the New England market.

The estimated capital cost of the MPC submitted by the project sponsors in MPUC Docket No. 2008-256 was \$625 million. Economic

³⁶ The MPC was submitted to the MPUC for a CPCN, which is required by state law for transmission construction in Maine. See 35-A M.R.S.A. § 3132. Although the Maine CPCN proceeding was eventually terminated by dismissal without prejudice, enough analysis had been undertaken to use the MPC as a hypothetical illustration here of how costs for such a project would have been allocated under the ITBM approach.

benefits of the project included energy cost reductions to consumers across New England totaling over \$1 billion in the first ten years of project operation³⁷ and an estimated \$50 million per year reduction in the cost of Renewable Energy Credits.³⁸ These estimates were further supported in a draft economic study conducted by ISO-NE. In that study, assuming construction of the MPRP and high fuel costs, the MPC would have a net present value benefit of \$842 million in reduced energy prices.³⁹

The application of the ITBM cost allocation for this project is complicated by the fact that approximately 30% of the reduced energy price occurs in the New Brunswick Power (“NB Power”) service territory. Were NB Power a FERC jurisdictional utility, this example would show how the ITBM’s use of the project economic impacts can facilitate the expansion of interfaces between control areas by sharing the economic benefits among regions.⁴⁰ As seen in Table 3 below, under the ITBM approach, Maine would pay a higher proportion of project costs (approximately 10% compared to 8% under the existing methodology) than it would under the current socialization method.

³⁷ See Central Maine Power and Maine Public Service Company, Request for Certificate of Public Convenience and Necessity for the Maine Power Connection to Enable Interconnection of Aroostook Wind Energy Project, MPUC Docket No. 2008-256, Petition and Initial Filing, July 1, 2008 (“MPC CPCN Filing”) Exhibit J (“LaCapra LMP Study”) at 13.

³⁸ LaCapra LMP Study at 39.

³⁹ Economic Studies Working Group (“ESWG”) Maine Power Connector Economic Analyses; May 23, 2008, Wayne Coste, Principle Engineer, Preliminary Report.

⁴⁰ In general, because the focus of these comments is intraregional transmission planning and cost allocation, the analysis is focused on intraregional costs and economic benefits. However, the ITBM may be a useful construct in the development of interregional cost allocation methodologies.

Table 3 MPC
Cost allocation under Current Methodology and ITBM

Local Networks	RNS (\$000)	ITBM (\$000)	Difference (\$000)
NSTAR	\$129,333.58	\$83,530	\$45,803
BHE	\$8,156.31	\$8,118	\$38
Fitchburg G&E	\$2,365.71	\$1,528	\$838
CMP	\$44,244.72	\$44,257	-\$12
Grid	\$174,642.46	\$112,793	\$61,849
NU	\$217,683.00	\$140,591	\$77,092
UI	\$22,394.10	\$14,463	\$7,931
Vtransco	\$26,176.53	\$16,906	\$9,270
NB Power	\$0.00	\$193,283	-\$193,283
MPS	\$4	\$9,530	-\$9,527
Total	\$625,000	\$625,000	

iv. Short Term Lower Southeast Massachusetts System Upgrades

The short term Lower Southeast Massachusetts (“SEMA”) System Upgrades are an example of a reliability project with large and highly localized economic benefits whose costs would have been allocated very differently under the ITBM beneficiaries pay approach than under the current New England pro-rata allocation.

Beginning in 2006, the increasing disparity between oil and natural gas prices resulted in decreased competitiveness of oil fired units in ISO’s dispatch. For Cape Cod, Massachusetts this resulted in the higher priced generation of the Canal generating stations not being dispatched in regular economic merit order. ISO developed operating procedures, called Local Second Contingency Protection Resources (“LSCPR”) that allowed out of merit dispatch of the Canal units to ensure adequate generation was committed to address second contingency protection for the loss of two major 345 kV lines. The LSCPR operation created significant out-of-merit

operating costs. To remedy this out of merit dispatch problem, ISO-NE identified nine separate transmission upgrade measures that became known as the “Short Term Lower SEMA Upgrades.” The Total Lower SEMA Project Cost was reported as \$82 million in the October 2009 ISO-NE project listing update.

During the four year period from 2005 to 2008, Lower SEMA congestion costs totaled over \$349 million, an average of more than \$87 million per year.⁴¹ ISO-NE’s Independent Market Monitor reported that congestion costs were alleviated by the “Short Term Lower SEMA Upgrades” put into service in 2009.

Transmission upgrades completed in 2009 significantly reduced congestion into Lower SEMA and Connecticut. In the day-ahead market, the average congestion-related price difference between the New England Hub and Lower SEMA fell from \$10.10 per MWh in 2008 to \$0.96 per MWh in 2009.⁴²

Table 4, below, provides a hypothetical illustration of how the costs of the SEMA⁴³ project might have been allocated under the ITBM compared to the way they were actually allocated under the existing tariff.

⁴¹ SEMA Municipals Presentation to Markets Committee on Lower SEMA LSCPR Charges 2006 – 2008 November 12, 2008

⁴² 2009 External Market Monitor Report at xii.

⁴³ *Id.* As discussed above, these are illustrative examples and would not necessarily equal the benefits distribution if the ITBM were in effect and the economic benefits were modeled prospectively, using LMP changes for example. In the SEMA case for example, the illustrative example is a reconstruction based on information available, relating to elimination of reliability costs discussed in market monitor reports not on LMP changes before and after the SEMA upgrades,

Table 4 Lower SEMA Upgrades
 Cost allocation under Current Methodology and ITBM⁴⁴

Local Networks	RNS (\$000)	ITBM (\$000)	Difference (\$000)
NSTAR	\$16,968,663	\$34,888,781	\$17,920,118
BHE	\$1,070,114	\$0	-\$1,070,114
Fitchburg G&E	\$310,382	\$0	-\$310,382
CMP	\$5,804,940	\$0	-\$5,804,940
Grid	\$22,913,223	\$47,111,219	\$24,197,997
NU	\$28,560,174	\$0	-\$28,560,174
UI	\$2,938,123	\$0	-\$2,938,123
Vtransco	\$3,434,381	\$0	-\$3,434,381
TOTAL	\$82,000,000	\$82,000,000	

5. Benefits of the ITBM

The two most significant benefits of the ITBM are (1) it will advance construction of public policy transmission projects to access renewables to comply with state renewable mandates and (2) it will allocate costs in a manner roughly commensurate with benefits consistent with the requirements of *Illinois Commerce Commission*. With regard to the first benefit, in New England it will advance the Commission’s interest by enabling construction of transmission to reach remotely located renewables in Northern New England. This is a critical consideration because many in New England believe that accessing renewables in New England is much more cost effective than paying for an extensive transmission build out to access renewables half-way across the United States.

As discussed above, there must be a way to move beyond the scenario planning and economic studies of how to deliver renewables from remote locations to load centers and actually begin to achieve the desired outcomes. By

⁴⁴ Both National Grid and NSTAR serve load in the SEMA area. We have so far been unable to identify the fraction of the load served by each and for this example, have simply allocated according to the relative size of the total load served by each company.

including such projects in the transmission plan, and allocating costs of such projects in a manner that is roughly commensurate with the benefits as determined at the planning stage of the project, the transmission lines that now just appear on scenario planning maps as “could be” or “should be” lines will be part of the ISO-NE RSP and thus under the ISO-NE tariff and Transmission Operating Agreement, transmission owners will have an obligation to build such lines (subject to state siting approval).

With regard to the second benefit, the ITBM establishes a means to bring regional cost allocation in compliance with the requirements articulated in the NOPR that transmission costs must be allocated in a manner roughly commensurate with the benefits received.⁴⁵ The ITBM will also bring fairness, equity, and transparency to cost allocation in New England. Stakeholders will be able to see, beginning at the planning stage, not only the reliability benefits of a project, but the economic benefits (including RPS compliance) as well.

IV. CONCLUSION

The specifics of the ITBM will need to be fully developed in the compliance phase. However, unless the Commission gives ISO-NE firm direction to work on the development of such a model, the status quo will continue and developing the abundant renewable resource potential that exists in New England, and that is required by existing public policy goals, will remain only a plan on a drawing board. Further, as transmission investment increases there is a greater need to align the cost impact of the investment with the benefits it provides, especially for ratepayers who do not see any apparent economic benefit from the project. Simply asserting that everyone benefits from high-

⁴⁵ NOPR at P. 147 ([T]he cost causation principle also requires the Commission to ensure that the costs allocated to beneficiary under a cost allocation method are at least roughly commensurate with the benefits that are expected to accrue to that entity.”)

capacity transmission facilities because they increase the reliability of the entire network will not be sufficient to justify having one set of ratepayers pay for transmission lines that predominantly benefit another set of ratepayers. For all of the reasons discussed above, the ITBM Proponents urge the Commission to direct ISO-NE to begin development of the ITBM as part of its compliance filing following the issuance of the rule.

Dated: September 29, 2010

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the service list compiled by the Secretary in this proceeding either by U.S. Mail or electronic service, as appropriate. Dated at Hallowell, Maine, this 29th day of September, 2010.

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