U.S. DEPARTMENT OF ENERGY

Comments of New York Regional Interconnect, Inc.

New York Regional Interconnect, Inc. ("NYRI") submits these comments in response to the request for comments set forth in the 2009 National Electric Transmission Congestion Study ("2009 Congestion Study") issued by the U.S. Department of Energy ("Department") on April 26, 2010. The Department requested comments on the study and on future steps for identifying and addressing electric transmission congestion. NYRI requests that the Department schedule a congestion technical conference to evaluate the lack of transmission investment in New York.

The Department concluded in the 2009 Congestion Study that the Mid-Atlantic Corridor (one of two areas designated by the Department as a National Interest Electric Transmission Corridor ("NIETC")), which includes the majority of New York State, including New York City, remains a Critical Congestion Area. The Department's congestion technical conference should focus on the northeast, in particular New York, to permit transmission providers, coordinators, customers, and developers of transmission and generation to meet and share their views on the region's congestion problems and possible solutions. A technical conference on transmission congestion would be particularly timely and significantly beneficial to the region which, as the Department reports, was "the only congestion area . . . in the Eastern Interconnection in 2009."[1]

[1] 2009 Congestion Study at xi.

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I. Description of NYRI and its Transmission Project

To place in context the barriers to economic transmission development in New York, consider NYRI's experience to date. NYRI is a privately-owned New York corporation proposing to build a transmission line (the "Project") in New York that would reduce congestion and improve reliability by increasing transmission transfer capability and providing additional reactive capability on the New York bulk power transmission system. NYRI is an independent transmission company with no affiliation to New York incumbent utilities that own transmission or generation, or sell power at wholesale and retail. NYRI's sole purpose is to finance, construct, own, and operate the Project. When completed, NYRI will turn over operational control of the Project to the New York Independent System Operator, Inc. ("NYISO") to allow for the provision of non-discriminatory access to energy market customers in New York. Once authorized, the Project will take fifty-two months to complete at an approximate cost of $1.8 billion. The construction will be funded entirely by private investors through a project financing mechanism. NYRI will not rely on public money, including Department grants or loan guarantees, to fund construction.

The Project consists of a 1200-megawatt ("MW") High Voltage Direct Current transmission line of approximately 190 miles between the Edic substation in Marcy, New York,

and the Rock Tavern substation in New Windsor, New York, in the NYISO control area. Once Project construction begins, NYRI will join the NYISO as a New York Transmission Owner.

The Project will relieve congestion, thereby reducing energy prices in the downstate New York area, which has some of the highest energy prices in the U.S. The Project will advance achievement of New York's aggressive reliability portfolio standard by providing transmission for less expensive renewable energy resources located in upstate New York and Canada to serve the concentrated load pockets in metropolitan New York. According to the Department, the NYRI Project would "pick up hydro generation and new wind projects planned in northern New York, off-shore in Lake Ontario, or elsewhere in Canada, and deliver it to load centers in down-state New York, tying to the electric distribution system serving Manhattan and northern New Jersey."[2]

The Project will improve reliability in the NYISO control area in three ways. First, by supplementing New York's backbone transmission system, the Project will relieve severe, persistent transmission constraints that have long existed in New York. Second, the Project will use sophisticated technology that will give NYISO the ability to bring the Project on-line as needed and to reverse polarity (i.e., divert or reverse the flow of power) if required. Third, the Project will provide downstate New York with much needed reactive capability.

The NYISO's System Reliability Impact System for the Project shows that the Project is expected to increase transfer limits to the highly constrained upstate New York-southeastern New York and Total East transmission interfaces in the New York System by about 1200 MW. Increasing these transfer limits will significantly improve the reliability of the New York transmission system. In its 2007 Comprehensive Reliability Plan, NYISO performed an analysis

[2] 2009 Congestion Study at 26.

showing that the Project improves the reliability of the system and enhances the capabilities of existing infrastructure.[3] In this regard, NYISO stated:

> Transmission projects also provide the flexibility to site additional resources in upstate New York and can provide other benefits. For instance, the NYRI has included reactive power capability for the Rock Tavern terminal, which could provide additional reactive capability for the Lower Hudson Valley.[4]

Because it relieves congestion between upstate and downstate New York, the Project will provide enormous economic benefits to New York electricity consumers.[5] According to CRA, the Project will save New York electricity consumers $570 million annually from 2012 through 2014, $636 million annually from 2015 through 2017, and $684 million annually from 2018 forward. In short, the congestion relief the Project will provide offers substantial consumer benefits.

II. Barriers in New York to Transmission Construction by Independent Transmission Companies.

We offer the Project as an example of the barriers and limitations independent transmission companies experience in New York. Despite (i) FERC's order unanimously awarding conditional incentive rates for compliance with its Order No. 679 requirements,[6] (ii) that the Project will reduce congestion within an area defined by the Department as a NIETC,

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[3] *See* pp. 48-49 and Table 6.17 of the 2007 CRP, available at www.nyiso.com/public/webdocs/newsroom/press_release?2007/crp_report_091807_final.pdf (dated September 18, 2007).

[4] *Id*. at p. 49.

[5] CRA International ("CRA") performed its analysis using its North American Electricity and Environment Model and GE MAPS, a detailed security-constrained economic dispatch and production costing model for electricity networks. A copy of CRA's analysis is included as Attachment 6 to NYRI's *Petition for Declaratory Order for Incentive Rate Treatment*, filed on February 12, 2008 in FERC Docket No. EL08-39-000.

[6] *N.Y. Reg'l Interconnect, Inc.*, 124 FERC ¶ 61,259, at P 2 & n.2 (2008).

and (iii) the Department's 2009 Congestion Study concluding that New York continues to be highly congested, the NYRI Project continues to face serious opposition.

NYRI sees the primary conflict to be the self-interest of incumbent New York utilities located in the southeast – the Elephant in the Room. The best objective evidence of this is the NYISO's White Paper, issued in November 2008, that succinctly identifies and describes the existing inherent biases that thwart attempts by independent transmission companies to invest in New York's bulk power facilities and to relieve congestion.[7] According to the White Paper:

1. The NYISO "veto" proposal may actually prevent transmission development in New York. According to the NYISO, beneficiaries should be "forced" to pay for transmission projects that NYISO, not the Load Serving Entities ("LSEs"), determine are cost-beneficial. The NYISO states that LSEs are "**loathe**" to pay for transmission projects that they themselves will neither own nor control, and have an incentive to veto a project that adversely affects their market investment in New York.[8]
2. New York significantly lags PJM Interconnection ("PJM"), ISO New England Inc., Ontario, and Quebec in transmission investment. In contrast to the approximately $8 billion investment—existing and planned—in each of PJM and ISO New England, "no major transmission lines between upstate and downstate New York have been built in more than 20 years."[9] Further, no system upgrades in New York to date have included facilities designed to relieve congestion or increase transfer capability.[10]

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[7] ESAI & NYISO, *Transmission Expansion in New York State: A New York ISO White Paper* (Nov. 2008) ("White Paper"). The White Paper is appended to these *Comments* at Attachment 1.

[8] White Paper at 4-7 to 4-8 (emphasis added).

[9] *Id*. at 4-7.

[10] *Id*. at 2-2.

3. The distinction between reliability and economic designations for transmission projects is arbitrary because "[a]ll transmission provides both reliability and economic benefits – even transmission identified as needed because of violations to reliability criteria."[11]

4. New York's transmission system is not adequately designed to meet New York's future energy needs[12] and NYISO lacks the authority to overcome LSE opposition to transmission construction.

5. NYISO's cost allocation methodology is unlikely to promote transmission investment and construction.

6. Transmission Congestion Contracts are worthless for promoting investment in transmission projects that are designed to reduce congestion.[13]

Barriers to investment include difficult siting processes; NIMBY-ism; and anticompetitive practices such as NYISO rules that (i) permit incumbent, downstate utilities to veto cost recovery by independent transmission companies under the NYISO's open access transmission tariff ("OATT"), (ii) limit the benefits that can be considered in a cost-benefit analysis for economic projects, and (iii) prevent independent transmission investors from voting on issues in NYISO committees.

In the White Paper, NYISO recognizes the conundrum that is its current transmission planning process:

> It is not clear whether the present NYISO transmission planning framework will lead to the construction of transmission for renewable resources. Under New York's beneficiary pays approach, the beneficiaries on these renewable transmission lines would fund their development. But, identifying the beneficiaries

[11] White Paper at 5-4.

[12] *Id*. at 4-1 to 4-6.

[13] *Id*. at 5-5.

> of a long-haul transmission line designed to connect remote upstate wind resources to the downstate load centers may require a new equation. Is it the generators connecting to the new line? Or, are the customers in the load centers the primary beneficiaries? If the benefits accrue to both, how should cost responsibility be allocated between them? Should the beneficiaries be all customers in New York State, given that the RPS is a statewide mandate? These are difficult questions for which the present NYISO process does not provide answers . . . .[14]

NYISO explained that it is more expedient for New York utilities with access to use submarine cables to interconnect with neighboring regional transmission organizations than it is to improve New York's transmission system:

> Cost allocation is the significant hurdle to this investment, as it has been for long before the existence of the NYISO. In the case of LIPA and NYPA, it was simpler (and quicker) to pursue and fund a new type of inter-regional transmission solution than to tackle in-state cost allocation issues. These entities were able to capture the benefits of their transmission projects by virtue of having captive customers and being able to enter into long term contracts.[15]

Of course, since PJM is part of the same NIETC as New York, allowing downstate New York utilities to lean on PJM, instead of upgrading and expanding New York's transmission facilities to access upstate New York's lower-cost and renewable resources, shifts New York's problems to New Jersey, and does not relieve congestion in the Mid-Atlantic Corridor.

The barriers described above deter investment in new transmission by independent transmission developers, particularly those that would seek cost-based recovery under the NYISO tariff.

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[14] White Paper at 4-3.

[15] *Id*. at 4-7.

III. Comments, Clarification, and Recommendation

Congestion in New York continues to be a problem five years after enactment of the Energy Policy Act of 2005.[16] The Department concluded in the 2009 Congestion Study that "the Mid-Atlantic Critical Congestion Area (extending from mid-state New York down to mid-Virginia) continues to experience high levels of transmission congestion."[17] The 2009 Congestion Study reported that "little new transmission has been built in the [Mid-Atlantic] region in the past three years," and "it is likely to be several years before current congestion levels ease."[18] The NYISO's White Paper concluded that there has been no significant transmission construction in New York in over twenty years and there has never been a transmission project constructed in New York to reduce congestion.[19] The Department specifically cites the "high electricity consumption and load growth of metropolitan New York City and Long Island, both of which are generation-short and face high electricity prices,"[20] as one of the region's greatest areas of congestion. The Department describes New York City as "an epicenter of transmission congestion."[21]

NYRI wishes to clarify the Department's conclusion in the 2009 Congestion Study that "it is not clear that [NYRI's withdrawal of its Project application] is due to legal challenges so much as to a failure by the project's planners to identify an adequate, low-risk cost recovery

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[16] Pub. L. No. 109-58, 119 Stat. 594.

[17] 2009 Congestion Study at x.

[18] *Id*.

[19] White Paper at 4-7 and 2-2.

[20] 2009 Congestion Study at 38.

[21] *Id.* at 44-45.

mechanism."[22] NYISO's cost allocation scheme permits an incumbent New York utility to prohibit an independent transmission company from receiving regulated cost recovery under the NYISO OATT. Consequently, absent pre-authorization by the incumbent utility, there is a great risk that an independent transmission developer may not recover its revenue requirement. Without even the opportunity of recovery, actual construction of congestion-reducing projects is highly unlikely. The Department recognized this dilemma in the 2009 Congestion Study: "[U]nder New York's cost allocation rules, transmission projects that significantly reduce congestion and prices downstate generally increase prices for upstate consumers without creating large net benefits overall,"[23] making such projects difficult to complete.

In response to the Department's request for future steps, NYRI requests that the Department facilitate a technical conference to discuss transmission congestion concerns, the barriers that hinder the construction of economic projects in New York State, and potential solutions. The technical conference should be broad; it should include participation from transmission providers, coordinators, customers, investors, and developers of generation and transmission. The technical conference should result in concrete steps to address transmission congestion and encourage transmission development in the constrained portion of New York and the Mid-Atlantic Corridor. Suggested topics could include the five primary factors NYISO identified for large-scale transmission expansion in New York:

- *Development and implementation of a renewable portfolio standard in New York* – The White Paper indicates that meeting New York's 30% by 2015 renewable energy mandate

[22] 2009 Congestion Study at 26.

[23] *Id.* at 49.

may require building significant capacity and the ability to move load to the congested downstate area.[24]

- *Emissions regulations* – The White Paper described New York as the largest emitter of the ten states participating in the Regional Greenhouse Gas Initiative, which was developed to simulate federal action to control carbon emissions. According to the report, significant transmission investment will be necessary to develop and move the renewable and hydropower energy resources that have more favorable emission attributes.[25]
- *Improving fuel diversity* – The White Paper reported that additional transmission would improve the fuel diversity of the constrained and congested downstate area, where fuel diversity and price volatility are major concerns, by providing access to non-gas-fired resources in other locations.[26]
- *Improved inter-regional trade* – The White Paper recognized that additional transmission investment would improve inter-regional supply and demand,[27] a concern the Department raised in the 2009 Congestion Study: "Until New York has better load and resource balance from sources within and close to New York City, Long Island and Westchester County, there will continue to be tension between New York's needs and PJM's, and significant price differentials across the region."[28]

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[24] *See* White Paper at 4-2 to 4-3.

[25] *Id* at 4-4.

[26] *Id*. at 4-5 to 4-6. The report notes that NRG Energy's Huntley project, if it had gone forward, would have been the first significant block of non-gas-fired generation in the New York in almost twenty years.

[27] *Id*. at 4-6 to 4-7.

[28] 2009 Congestion Study at 51.

- *In-State capacity and energy price differentials* – the White Paper recognized that cost allocation is a significant hurdle to transmission investment in the State and region, and that utilities will protect their franchise area.[29]

The technical conference could address concerns raised by PJM's staff, market participants and state regulators concerning the tendency of southeastern New York utilities to build direct lines to access PJM's lower-priced energy instead of developing transmission to access upstate New York's lower-cost and renewable resources. Leaning on PJM as a source of power for metropolitan New York places a potentially unreasonable burden on PJM's transmission system and customers, while providing select New York utilities that have quick and exclusive access to PJM's market the ability to avoid upgrading New York's transmission system.

NYRI appreciates the opportunity to submit these comments on the Department's 2009 Congestion Study, and would be happy to meet with the Department to further discuss its comments and the proposed technical conference.

Respectfully submitted,

/s/ Richard Muddiman

[29] White Paper at 4-7 to 4-8.

ATTACHMENT 1

Transmission Expansion in New York State

A New York ISO White Paper

November 2008

The NYISO worked with ESAI to draft this Transmission Expansion White Paper in order to review the potential and actual drivers of transmission expansion activities in New York State and its neighboring control areas. While PJM and ISO-NE have facilitated a great deal of investment in transmission expansion projects to address reliability, it appears that the NYISO will be able to best promote transmission expansion through the development of its economic planning process and the Congestion Assessment and Resource Integration Studies which will begin after the 2009 CRP is issued.

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1. Introduction

The bulk electric transmission system is often referred to as the interstate highway system for competitive wholesale electric markets. The infrastructure that exists today plays a vital role in the restructured electric industry in the northeast as well as other regions of the country. The transmission system that will be needed in future is essential to the continued operation of efficient and reliable wholesale power markets. As such, transmission planning and investment has been of paramount concern for the Federal Energy Regulatory Commission (FERC). In his testimony given on July 31, 2008 before the Senate Committee on Energy and Natural Resources, FERC Chairman Joseph Kelliher stated:

> "The Commission has three overarching goals: first, to protect the reliability of the bulk power system; second, to assure open and nondiscriminatory access to the transmission grid, the interstate highway system for wholesale power sales; and, third, to encourage development of a robust transmission grid. There is a relationship among these goals. It is not enough to have open access to the grid - the grid itself must be robust enough to assure reliability and support competitive wholesale power markets."

This white paper presents a review of the NYISO planning and market mechanisms designed to facilitate investment in transmission infrastructure within the New York Control Area (NYCA). The paper also evaluates the factors at play in the neighboring control areas where a significant number of transmission expansion projects are currently being developed. The reliability planning processes in PJM and ISO New England (ISO-NE) have a large role in these transmission investments and are discussed in detail. The cost allocation and cost recovery mechanisms in place also have a significant role in facilitating the current level of transmission buildout occurring in the two control areas. The NYISO's Comprehensive Reliability Planning Process (CRPP) is a unique "all-source" process that is significantly different from the other regions' planning processes. Its cost allocation/cost recovery mechanisms are also rooted in the NYISO's "beneficiary pays" principle.

The paper also discusses the role New York State policy makers and regulators may play in transmission investment and expansion decisions. Several New York State policies currently in place increase regulatory uncertainty for developers of transmission projects. Some policies and objectives such as renewable energy targets and fuel diversity concerns would likely benefit from transmission expansion. Others, such as carbon emission limits, may offset the need for additional transmission. Finally, the paper considers opportunities to increase transmission investment in New York to support system reliability and meet state goals, following the NYISO's beneficiary pays principle.

2. NYISO Transmission Planning and Market Mechanisms

The New York Independent System Operator, Inc. is an independent, not-for-profit corporation established to facilitate and administer the wholesale electric markets in New York and to ensure continued reliable operation of New York State's bulk power transmission facilities. The NYISO assumed full responsibility for the operation of the system from the New York Power Pool on December 1, 1999. A central principle of the NYISO is to provide accurate, open and transparent planning information to allow market participants to determine what resources are developed and built. From its beginnings, the NYISO undertook a primary role in conducting various planning studies in coordination with the six investor-owned utilities (collectively New York Transmission Owners, or TOs):

1) Central Hudson Gas & Electric Corporation
2) Consolidated Edison Company of New York, Inc.
3) New York State Electric & Gas Corporation
4) Niagara Mohawk, a National Grid Company
5) Orange and Rockland Utilities, Inc.
6) Rochester Gas and Electric Corporation

And two public authorities:

1) Long Island Power Authority
2) New York Power Authority

NYISO planning studies are subject to the requirements of its FERC-approved tariffs and are governed by the reliability rules established by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the New York State Reliability Council (NYSRC). While the NYISO coordinates and conducts its system transmission studies, it relies on the power of the markets to determine which resources are financed, constructed and operated. The NYISO does not expressly direct or determine future system expansion activities,[1] but it closely evaluates and monitors the reliability of the system and any prospective changes to it.

The Commission continues to recognize that there are significant challenges for transmission planning and investment under its restructured wholesale markets and open access policies. FERC stated its concerns regarding the lack of adequate transmission investment in Order No. 890, issued on February 16, 2007 and the subsequent orders on rehearing and clarification, Orders No. 890-A and 890-B.

In response to Order No. 890 mandates, the NYISO and its market participants have expanded and enhanced the NYISO's planning role — principally in the area of

[1] A limited exception exists in the case of a NYISO determination that a regulated backstop solution is needed to meet a Reliability Need identified in the CRPP. In the event that the NYISO triggers a regulated backstop solution, the New York TOs have agreed to proceed with the siting, design and construction of the backstop project.

economic planning — while remaining committed to the NYISO's central philosophy of allowing markets to determine what resources are proposed, developed and constructed. While significant market-based investments have been occurring in New York, transmission development activity has been more restrained than in the neighboring control areas, PJM and ISO-NE, which are experiencing a significant investment in new transmission as a result of their respective reliability planning processes. The NYISO recognizes that several statewide policy initiatives, such as the Energy Efficiency Portfolio Standard (EEPS), the Regional Greenhouse Gas Initiative (RGGI) and the Renewable Portfolio Standard (RPS), may delay or otherwise interfere with market responses to the NYISO's planning efforts unless care is taken with respect to their implementation.

The NYISO's Current Transmission Planning Processes

The NYISO assumed responsibility for conducting various planning studies on behalf of the New York TOs in 2000. These studies can be broken down into two general timeframes: 1) the operating timeframe (1 year or less) and 2) the planning timeframe (looking out several years). In general, the operating studies represent the existing transmission system and system conditions expected to occur during the respective seasonal peak load periods. NYISO conducts planning studies as the transmission service provider for the NYCA in coordination with the New York TOs and in accordance with its Open Access Transmission Tariff (OATT). The NYISO, however, pursuant to section 3.10(e) of the NYISO/TO Agreement, cannot direct a Transmission Owner to modify or expand its transmission system. A limited exception to this provision has been established with respect to the NYISO's triggering of a reliability backstop solution through its CRPP.

Interconnections & Transmission Service Studies

The NYISO is responsible for all transmission interconnections in New York under the provisions of the OATT. Pursuant to this authority, the NYISO conducts comprehensive studies for the interconnection of large and small generators and merchant transmission projects. These studies and the cost allocation/cost recovery requirements are governed by Attachments S, X and Z of the OATT.

The interconnection study process ultimately identifies Attachment Facilities as well as System Upgrade Facilities (SUFs) that are required to interconnect the project to the transmission network. The costs of Attachment Facilities are borne by the project developer. Costs of SUFs are allocated by the NYISO among a "Class Year" of interconnection projects. Cost allocation is pro-rated pursuant to each project's relative impacts when compared to other projects in the same Class Year. Those projects assigned a cost responsibility by the NYISO for SUFs are eligible to be reimbursed by subsequent projects that are able to interconnect utilizing excess capacity provided by the SUFs or "headroom." To date the SUFs installed have primarily addressed short circuit and system protection issues as well as basic infrastructure to connect the new facilities, and have not included facilities that relieve congestion or increase transfer capability.

Comprehensive Reliability Planning Process (CRPP)

The NYISO CRPP, as provided in Attachment Y of the OATT, is a primary tool the NYISO employs to inform transmission expansion and electric resource infrastructure investment decisions in the New York Control Area. Developed through its stakeholder governance process, the CRPP establishes that the NYISO will identify reliability needs and administer a process whereby solutions are proposed, evaluated and implemented in order to maintain the reliability of the bulk power system.

The CRPP is a unique, "all source" reliability planning process that evaluates transmission, generation and demand response on a comparable basis. This is true whether the solutions are market-based or regulatory. The CRPP is conducted in a fully open and transparent two-step process:

1) Identify reliability needs based upon existing reliability criteria
2) Solicit solutions from the marketplace and evaluate whether they satisfy the reliability need.

The results of the NYISO's analysis are contained in its Comprehensive Reliability Plan (CRP), which is the culmination of each CRPP planning cycle.

2008 Comprehensive Reliability Plan

The 2008 Reliability Needs Assessment (RNA) identified a reliability need in the year 2012 as the result of a statewide capacity deficiency as well as a zonal deficiency caused by transmission constraints. The need could be resolved by adding capacity resources downstream of the transmission constraints or by adding resources upstream of transmission constraints in conjunction with transmission reinforcements. Accordingly, the RNA designated all TOs, except for the New York Power Authority (NYPA), as the Responsible TOs required to identify a regulated backstop solution to the reliability need. The backstop may be called upon by the NYISO in the event a market-based solution is not available.

The NYISO solicited market-based projects, which are preferred solutions within the CRPP, and requested that the Responsible TOs submit regulated backstop solutions to the identified reliability needs. Alternative regulated solutions were also solicited. All the projects submitted were evaluated by the NYISO to determine if the reliability needs would be met. The 2008 CRP indicated that over 3,800 MW of market-based solutions were received by the NYISO, representing sufficient solutions to the 2350 MW of identified reliability needs. The CRP also deferred the initial reliability need from 2012 until 2013 with the incorporation of an updated TO plan to deliver firm capacity to New York via the Neptune RTC project — a market-based HVDC transmission project connecting Long Island to PJM.

The NYISO has not yet triggered a regulatory backstop or alternate regulatory project in any of the three CRPs conducted to date because market-based projects continue to be developed and constructed to meet the growing demand for electricity in New York. The next round of the CRPP has begun and the draft 2009 RNA Assessment is due to be completed in the fall of 2008.

Cost Allocation and Cost Recovery for Regulated Projects

Regulated transmission projects are provided cost recovery through the CRPP's proposed cost allocation/cost recovery methodology, which was developed by the NYISO and its stakeholders through the Electric System Planning Working Group (ESPWG). In compliance with FERC's Order 890, the proposed tariff language was submitted to the Commission on June 18 and June 27, 2008, as revisions to Attachment Y and Schedule 10 of the NYISO OATT. This methodology, pending its approval by FERC, is firmly rooted in the NYISO's beneficiary pays principle.

The cost allocation process is conducted in three steps that determine whether a need is locational, statewide, or bounded by a specific region in the NYCA. It is consistent with both the compensatory MW approach that is an integral feature of the RNA and the existing cost allocation methods used in NYISO markets.

A Reliability Facilities Charge (RFC) is the proposed cost recovery mechanism for regulated transmission solutions proposed, developed and constructed pursuant to the CRPP. The RFC uses a volumetric charge rather than a demand charge to recover the cost of reliability upgrades. Presently, all cost recovery for transmission facilities authorized by the NYISO OATT are volumetric in nature. The methodology for calculating the RFC is very similar to the methodology that the NYISO uses to calculate the Transmission Service Charge (TSC) and the NYPA Transmission Adjustment Charge (NTAC), which are the charges used to recover the embedded costs of the existing transmission facilities owned by the TOs.[2] The RFC is comprised of the revenue requirements for (i) each regulated reliability project filed with FERC by a TO; (ii) any costs incurred by NYPA that are filed with FERC by the NYISO; and (iii) any FERC approved costs incurred by an Other Developer. Costs incurred by LIPA are recovered through a separate LIPA RFC. The monthly RFC rate ($/MWh) is billed by the NYISO to all LSEs (TOs, municipal systems and competitive LSEs) that are located in load zones identified pursuant to the three step cost allocation process. Cost recovery for regulated non-transmission projects is governed by the State of New York Public Service Law.

Economic Planning Process

Currently, the CRPP contains an economic planning component that consists solely of a methodology for the analyses and reporting of the congestion costs on the system. The risks and costs of a project developed in response to this limited economic planning component of the CRPP are borne solely by those market participants sponsoring such a project.

[2] The TSC is a license-plate cost recovery mechanism. NTAC is a postage-stamp cost recovery mechanism for NYPA's facilities because it owns and operates facilities across the state and does not have any geographic franchise areas.

Comprehensive System Planning Process (CSPP)

In response to Order No. 890, the Commission's Final Rule on Open Access Reform, the NYISO proposed to adopt an expanded planning process, which will supplant the CRPP and be known as the Comprehensive System Planning Process (CSPP). The core elements that comprise the CRPP remain and are enhanced by the CSPP proposal. In addition, the CSPP proposal provides a framework for coordinating the local TOs' planning processes in an open and transparent manner, and provides for comparable cost allocation/cost recovery for all regulated projects that remains consistent with the NYISO's beneficiary-pays philosophy. The proposal also creates a new economic planning framework for the NYISO.

The CSPP is comprised of three major components/activities:

1) Local transmission planning
2) Regional reliability planning
3) Regional economic planning.

The proposed two year planning cycle under the CSPP will start with an open and transparent review of the Local Transmission Planning Processes conducted by the New York TOs. The local transmission plans will then be incorporated into the NYISO's RNA and CRP. The economic planning component — the last step in the process — will be conducted after a CRP is issued by the NYISO. In conducting the economic component of the planning process, the NYISO will provide system information regarding the impacts and potential remedies to congestion and resource integration that will inform Market Participants to act in their own best interests. Upon input of the Market Participants, the NYISO will conduct a series of three congestion studies, which will be known as the Congestion Assessment and Resource Integration Studies (CARIS). Additional studies requested by individual market participants may be conducted along with the CARIS at their own expense.

The CARIS proposal introduces a new economic planning process to complement the CRPP. Each CARIS cycle will be based upon the most recent CRP. The CARIS proposal requires the NYISO to first determine whether a proposed economic project would be eligible for regulated funding under the OATT and then to identify the prospective beneficiaries that would be assigned the costs of the project pursuant to the NYISO's beneficiary pays principle. Beneficiaries are broadly defined as those that gain economic benefits from the project. The NYISO will conduct a beneficiary determination for cost allocation purposes based upon relative LBMP load savings over the first 10 years of the project's life. A super-majority of the identified beneficiaries (80% or greater) is required to approve the project to receive regulated funding. If the proposed project meets the required super-majority vote and the project is implemented, all designated beneficiaries, including those that voted against implementation, will pay their allocated portion of the project costs.

Discussions regarding implementation of the CARIS are currently underway through the NYISO stakeholder process. It is anticipated that the first CARIS will begin during the summer of 2009, pending FERC approval.

NYISO Market Mechanisms Incenting Transmission Investment

In Order No. 2000, FERC instructed ISOs/RTOs to "encourage market-driven operating and investment actions for preventing and relieving congestion." From its beginnings, the NYISO and its stakeholders have been fully anchored in this market-based, beneficiary pays concept with regard to system improvements. This philosophy, which is at the core of the NYISO's market structure and market rules — and well established in the CRPP — has been fully supported by New York stakeholders, the New York State Public Service Commission (NYSPSC) and the FERC. To this end, the NYISO markets rely on open and transparent processes with maximum stakeholder participation.

Locational Based Marginal Pricing

The wholesale energy markets operated by the NYISO rely on locational based marginal pricing (LBMP) to provide the transparent costs of serving load across the transmission system. The congestion component of the LBMP reflects the marginal cost differentials between power generation in load zones when transmission limits exists. This transparent price signal is a primary driver of a market participant's investment decisions in new transmission and generation.

The NYISO's markets and LBMP pricing signals provide the benefits of competition while achieving the intended results. Over 6,000 MW of new generation and nearly 1,000 MW of merchant transmission have been added in the NYCA since the inception of the NYISO. The majority of this development has occurred in southeastern New York where LBMPs are generally much higher than areas further north and west.

Transmission Congestion Contracts (TCCs)

As part of its LBMP market system, the NYISO issues Transmission Congestion Contracts or TCCs to provide a mechanism for market participants to allocate congestion costs. A TCC is a financial right that is a hedge against the LPMP difference between the source and the sink of generation. Each TCC issued specifies an injection (source) and withdrawal (sink) point on the system for one MW of energy. The holder of the TCC is entitled to receive, or obligated to pay, the difference between the congestion component of the LBMP between the injection and withdrawal points in the NYISO's Day-Ahead Market. The TCCs held by TOs, with the exception of certain grandfathered Transmission Service Agreements, are offered for sale through NYISO-administered auctions. The revenues from these sales flow to the TOs and are credited to the TO's monthly Transmission Service Charge (TSC), reducing transmission customer charges.

The NYISO also awards expansion TCCs to the owners of projects that increase system transfer capability. The expansion TCCs are awarded to the owner of the facility

for 20 to 50 years, starting from the commercial operation of the transmission expansion project.

As indicated by the small volume of incremental TCCs issued by the NYISO to date, short-term TCCs, by themselves, appear to provide little incentive to build new transmission facilities. One explanation for this may be because the term of the contract is considerably less than the term of the investment. FERC Order No. 681 mandated a process for allocation of Long-Term Transmission Rights (LTTRs) for eligible LSEs and also made them available to transmission upgrades and expansions by any party that pays for the upgrade or expansion in accordance with the prevailing cost allocation methodology. LTTRs may provide an additional incentive to build transmission because it is possible to lock in the benefit for a period closer to the duration of the initial investment. Because the value of a TCC is likely reduced by adding transmission, however, capturing the congestion price differentials requires that a long-term energy contract be tied to the transmission expansion project.

Unforced Capacity Deliverability Rights (UDRs)

Unforced Capacity Deliverability Rights or UDRs are rights associated with new incremental controllable transmission projects that provide a transmission interface to a local area in the New York system that has a minimum locational installed capacity requirement. Currently UDRs can be obtained for transmission interfacing with Zones J and K (New York City and Long Island, respectively). When combined with contracts for unforced capacity, UDRs allow such unforced capacity to be treated as if it were located within the zone and allows the capacity to contribute to the locational capacity requirement in place for that zone. External UDRs are assigned where the controllable transmission project interfaces with an external control area, such as ISO-NE or PJM. Local UDRs are also available where the transmission project interfaces with a non-constrained region in New York. Currently the NYISO has assigned nearly 1000 MW of external UDRs for two projects: Neptune RTC and the Cross Sound Cable.

Capacity Resource Interconnection Service (CRIS)

On March 21, 2008 FERC approved the Consensus Deliverability Plan of the NYISO and the New York Transmission Owners (Deliverability Plan) which was submitted on October 5, 2007. The Deliverability Plan outlines a framework for a second level of interconnection service in the NYISO, which contains a deliverability component as required by the Commission in Order No. 2003. Under the NYISO's Deliverability Plan a generator can elect from two categories of interconnection service: Energy Resource Interconnection Services (ERIS) or Capacity Resource Interconnection Service (CRIS). These are not mutually exclusive.

ERIS relies on the NYISO's minimum interconnection standard and only allows the generator to participate in the NYISO's energy and ancillary services markets. A generator that elects and qualifies for the CRIS, however, can also participate in the NYISO's Installed Capacity (ICAP) Market. For generation with sufficiently high unforced capacity ratings, the ability to increase ICAP sales should provide a significant

incentive to pay for incremental transmission. However, for intermittent and other resources with low capacity values it is unlikely that sufficient economic benefits from CRIS would outweigh the costs of the incremental transfer capacity.

3. Transmission Expansion in Neighboring Control Areas

PJM

The largest power market in the world, PJM juxtaposes two disparate power markets: a coal-based, net export market to the west, and an urban load center to the east that is largely dominated by newer gas-fired generation. As a result, congestion between eastern and western PJM is common and persistent. PJM is actively addressing this situation by authorizing a substantial amount of regional "backbone" transmission improvements based upon reliability needs. (Appendix A provides a summary of the backbone 500 kV and 765 kV projects underway in PJM.)

PJM has also undertaken a significant review of its transmission cost allocation mechanism, resulting in the adoption of postage-stamp, 'socialized' rate recovery mechanisms for new backbone (500 kV and above) transmission projects. These policies resulted in a significant increase in planned transmission investment, as shown in Figure 3-1.

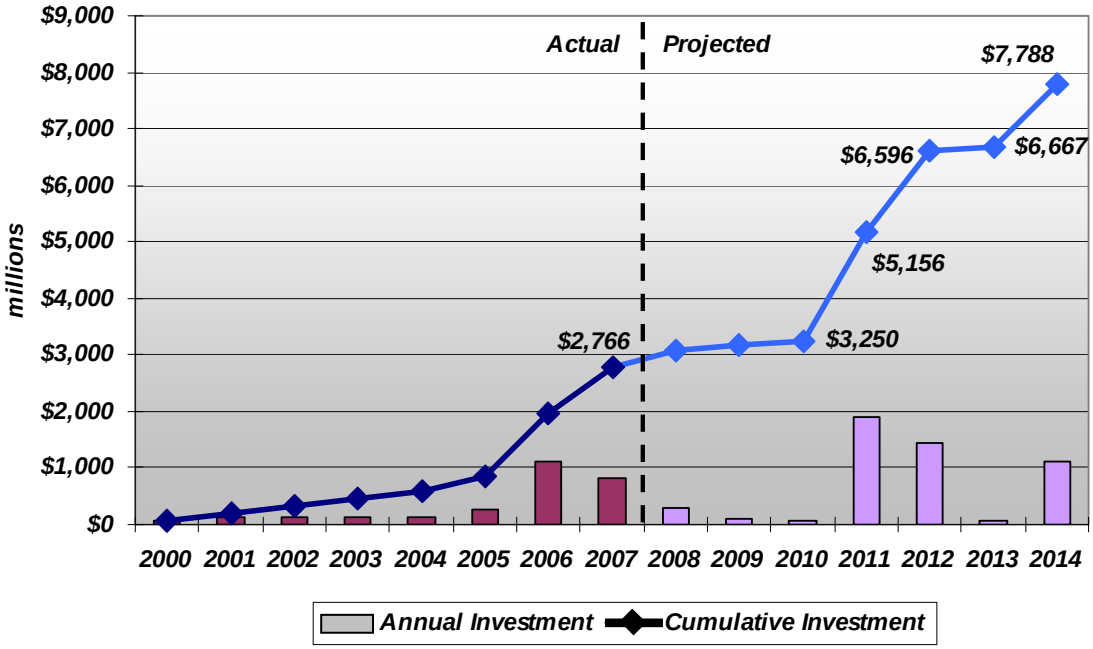

Figure 3-1: PJM Transmission Investment, 2000-2014

Since 2000, PJM has added almost $3 billion in new transmission investment. Figures from the latest Regional Transmission Expansion Plan (RTEP) indicate a substantial acceleration in investment in 500 kV and 765 kV backbone projects, with another $5 billion in transmission investment expected to be added by 2014.

PJM's Reliability Driven Projects – Cost Allocation and Recovery

Under its RTEP, PJM identifies transmission system updates necessary to preserve the reliability of the PJM-administered system. PJM employs a hybrid cost allocation mechanism that differentiates between existing and new transmission investment, and further differentiates new investment based on voltage level. Like New York, cost recovery for existing facilities occurs via a license plate (referred to in PJM as "zonal") rate design, under which PJM transmission customers pay for transmission service based on the zone in which their loads were located.

For new facilities below 500 kV, PJM determines the beneficiaries of the expansion or upgrade and assigns cost responsibility on that basis. This identification and assignment is done on a zonal basis, i.e., PJM assigns the costs of every planned project to the license plate rates of one or more transmission owners in the PJM system. In this manner, a significant portion of transmission upgrade costs can be assigned to zones (transmission owner footprints) other than the zone(s) in which the facilities are built. To identify beneficiaries and assign costs, PJM uses a mechanism based on a distribution factors (DFAX) analysis, which represent the distribution of power flow over specific transmission facilities.

Costs of all new PJM-planned facilities that operate at or above 500 kV are shared on a region-wide basis via a postage stamp rate. This postage stamp rate is a recent development in PJM, as approved by FERC in Opinion No. 494.

While the NYISO and PJM 'beneficiaries pay' and license plate transmission rate frameworks for reliability projects may appear similar, closer inspection reveals important differences:

- PJM has the authority under its tariff and RTO operating agreements to identify the load zones that are the beneficiaries of a transmission upgrade and subsequently allocate the costs of such an upgrade to the transmission owner license plate rate(s) for the identified load zone(s). While the NYISO has the ability to require transmission owners to proceed with licensing and construction of reliability backstop projects, it lacks a mechanism for assigning responsibility for the upgrade costs among multiple transmission owners. The New York transmission owners have agreed to develop such a mechanism as part of the NYISO's Order 890 Compliance filing.
- PJM's authority extends over a multi-state region under FERC jurisdiction, while the NYISO's single-state control area creates conflicts between federal and state jurisdiction. Of course, PJM's authority is also subject to jurisdictional questions, but ultimately FERC has stepped in to resolve federal-state (and state vs. state) conflicts. It is not clear whether FERC would have the same type of preemptive jurisdiction over a single-state ISO.
- While rooted in beneficiary pays mechanisms, PJM has decidedly moved to incorporate regionalization of costs. FERC's 2007 decision to regionalize the costs of new backbone projects (Opinion No. 494) is a watershed event for

transmission in PJM. This new regional rate will ultimately recover several billion dollars of transmission investment; however, FERC's decision is opposed by several PJM stakeholders and state regulators.

PJM's Economic and Market-Driven Projects – Cost Allocation and Recovery

PJM's planning process for economic or "market efficiency" transmission expansions includes a variety of forward-looking metrics to measure the benefits of proposed upgrades (listed below in "PJM Metrics for Economic Planning"). The forward-looking metrics include long-term forecasts of various measures of consumer payments. PJM uses these metrics to determine whether new economic transmission project proposals would provide sufficient benefits to justify adding them to the RTEP. The metrics are also applied to existing reliability-based projects already in the RTEP to determine whether they provide sufficient additional economic benefits to justify their expansion, modification or acceleration.

PJM Metrics for Economic Planning	
1)	Total production costs (fuel plus variable O&M)
2)	Total load payments (load times LMP paid by load)
3)	Total generator revenue (generator MW times generator LMP)
4)	Zonal load payments (zonal load MW times zonal LMP)
5)	Zonal FTR credits (measured using currently allocated Auction Revenue Rights (ARRs) plus additional ARRs made available by the proposed new economic upgrade or the expansion/acceleration of a planned reliability-based upgrade)
6)	Total transmission system losses
7)	Total RPM capacity payments.

The PJM economic planning mechanism uses a benefit/cost ratio to determine whether an economic upgrade will be included in the RTEP. To be included, a project's benefit/cost ratio must be at least 1.25 to 1, i.e., benefits must exceed costs by 25%. The benefit/cost ratio is calculated by dividing the present value of the total benefit for each of the first 15 years of the life of the project by the present value of the total cost for each of its first 15 years. The assumptions for determining the present value of the benefits and costs (e.g., discount rate and annual revenue requirement) are set annually by the PJM Board.

The cost component of the benefit/cost ratio is based on the revenue requirement of the economic upgrade for each of the first 15 years of the life of the upgrade. The benefit component of the benefit/cost ratio includes both energy and RPM capacity market benefits and is weighted using a 70/30 ratio that places more weight on the benefits of reduced production costs and RPM clearing prices.

Economic upgrades that meet the benefit/cost test will be included in PJM's RTEP, subject to approval by the PJM Board. PJM will then:

- Designate the construction, ownership or financing responsibilities of entities involved in the project
- Provide a cost estimate of the upgrades
- Indicate which market participants will bear the costs of the upgrades.

Cost allocation for economic upgrades has been the subject of much dispute in PJM. In late July 2008, FERC approved a settlement that established cost allocation for economic upgrades as follows:

- 500 kV and above — regionalized via a regional postage stamp rate (as done for reliability upgrades);
- Below 500 kV and based on enhancement or acceleration of reliability upgrades already in the RTEP — assigned on a beneficiary pays approach using the DFAX analysis for expansions/modifications and a combined DFAX and LMP-based analysis for accelerated projects;
- Below 500 kV and economic-only — Cost allocation for upgrades solely for the purpose of relieving economic transmission constraints remains under development. PJM will file an allocation method for such economic-only upgrades by August 2009.

In addition, PJM, Midwest ISO and stakeholders are engaged in discussions to develop a cost allocation mechanism for cross-border economic transmission projects, with an objective of developing a consensus proposal by the end of January 2009. PJM and MISO have been under a FERC directive to develop such a methodology since September 2004; however, FERC has granted several postponements upon requests from the ISOs and their stakeholders.

Turning to the process for market solutions, PJM has two methods for including market solutions in the RTEP:

1) In order to be considered in the market efficiency analysis commencing after PJM Board approval of the RTEP in June of each year, proposals to construct economic upgrades must be submitted by December 31 of the same year.
2) Alternatively, market-based generation or merchant transmission proposals to address an economic constraint may at any time submit an interconnection request pursuant to the PJM tariff. There are several market-based transmission projects following PJM's merchant transmission interconnection process (the merchant transmission queue had 17 projects as of August 1, 2008).

To date, however, the only market-based transmission projects that have entered service or are under construction in PJM are primarily designed to export energy and capacity to New York:

- The 65-mile, 660 MW Neptune HVDC cable between Sayreville, New Jersey and Long Island (in service July 2007)

- The Linden Variable Frequency Transformer (VFT) project, a device installation expected to provide an additional 300 MW of transfer capability over existing transmission lines between New Jersey and New York City (presently under construction and estimated to be in service in summer 2009).

In contrast to the NYISO, PJM's economic planning and cost allocation mechanisms are extensive and significantly more developed. This advanced stage of development is mostly attributable to the fact that PJM was ordered to develop such mechanisms as a condition of its approval as an RTO. PJM's economic planning mechanism contains specific criteria for measuring benefits and costs as well as specific benefit/cost tests for evaluating projects that are similar to the NYISO's proposed CARIS process. Although PJM has had an economic planning process in place for several years, to date there have been no economic projects identified pursuant to this process, likely because of continued litigation and numerous FERC compliance filing obligations. (Appendix B provides a "PJM Transmission Rate Design and Cost Allocation Case History at FERC").

ISO-NE

New England has a long history of regionalization of transmission costs across the six New England states that pre-date the establishment of ISO-NE. Presently, all 345 kV facilities and most 115 kV transmission lines in New England are deemed to be Pool Transmission Facilities (PTF) and thus recovered via a postage stamp Regional Network Service (RNS) rate.

After decades of virtually no investment, New England is in the midst of a transmission investment boom, driven largely by a robust ISO-administered reliability planning process and the resolution (for the most part) of cost allocation issues. From 2002 through 2007, a total of $1.2 billion in transmission investment has been added to the New England system. Most of this transmission is intended to address two significant load pockets on the ISO-NE system: Southwest Connecticut (SWCT) and the greater Boston metropolitan area.

ISO-NE forecasts that another $7 billion of reliability-driven projects will be added, as identified in the July 2008 update of ISO-NE's Regional System Plan (RSP). New transmission added since 2002 and planned through 2012 amounts to an impressive $8.1 billion. Figure 3-2 details transmission investment in New England since 2002, and includes projected investment through 2012 as identified in the latest ISO-NE RSP.

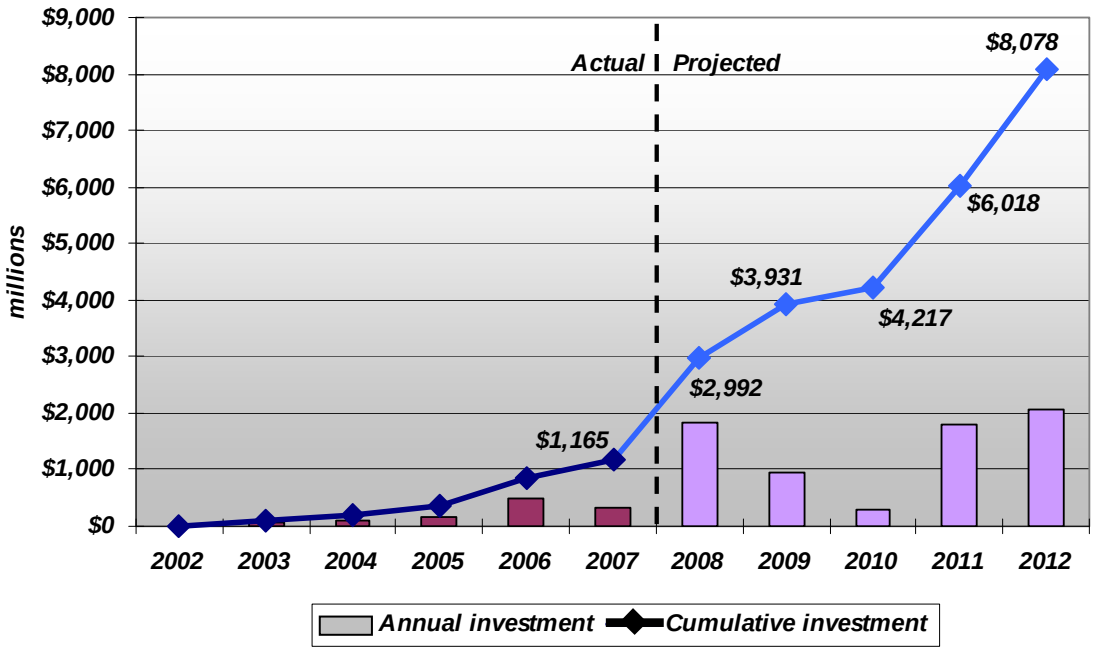

Figure 3-2: New England Transmission Investment, 2002-2012

Appendix C provides a summary of major transmission projects planned and underway in New England.

ISO-NE's Reliability Driven Projects – Cost Allocation and Recovery

ISO-NE identifies transmission system updates necessary to preserve the reliability of the New England transmission system. Pursuant to the ISO-NE tariff and the Transmission Operating Agreement between ISO-NE and the New England transmission owners, ISO-NE mandates the construction of reliability-driven projects identified in the RSP and designates entities (Transmission Owners) responsible for constructing the upgrades.

The costs of all existing transmission facilities in New England are recovered via a pool-wide postage stamp rate for Regional Network Service (RNS). As a result, transmission charges are effectively allocated to all New England customers based on their contribution to the system-wide peak demand. The RNS rate is neither location nor distance sensitive, and customers pay based on their (coincident) contribution to system peak demand. To recover the costs of existing radial facilities and other local transmission elements, the New England framework also includes a version of license plate rates referred to as the Local Network Service Rate (LNS Rate).

The ISO-NE tariff's Transmission Cost Allocation (TCA) process determines cost recovery for transmission facilities rated at 115 kV and above. The TCA process applies participant funding (i.e., recovery via a local LNS Rate) to elective transmission upgrades, generator interconnection related upgrades, merchant transmission facilities,

local benefit upgrades, and localized costs.[3] In all other instances (which constitute the bulk of planned transmission facilities), transmission upgrades that produce regional benefits receive regional cost support via the RNS Rate. (See Figure 3-3). The TCA method applies to upgrades identified in ISO-NE's transmission planning process as either reliability or economic upgrades (defined as providing net economic benefits to the region).

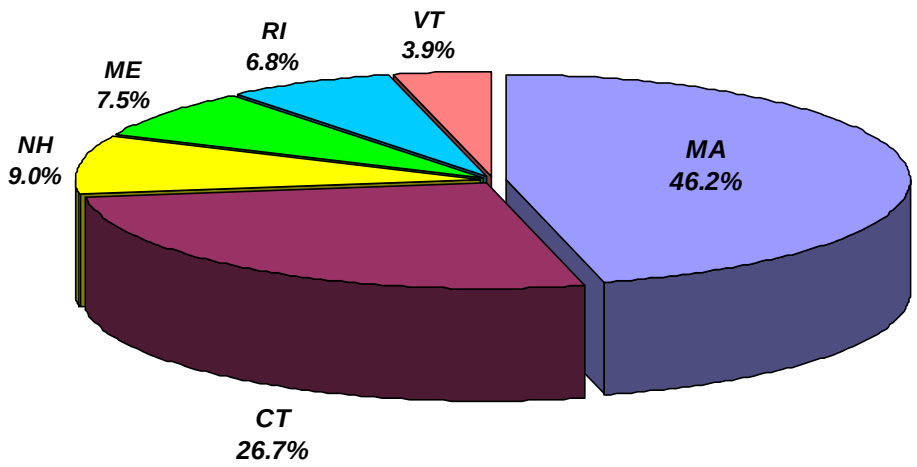

Figure 3-3: State Cost Responsibility Under New England RNS Rate
(2008 Regional System Plan 50/50 Forecast)

New England's socialization presents a stark contrast to New York's beneficiary pays framework.

While both NYISO and ISO-NE have similar authority to provide for construction of reliability-driven transmission projects, New England's regional rate recovery framework has mostly resolved the issue of assigning cost responsibility. As a result, significant reliability-driven projects are underway without the difficulties of having to assign responsibility for the upgrade costs among multiple transmission owners. However, Maine and Massachusetts have begun to question the appropriateness of the ISO-NE cost allocation protocols, particularly in light of the several billion dollars of planned reliability investment and its resulting rate impact on customers in those states.

Like PJM, ISO-NE's authority extends over a multi-state region under FERC jurisdiction, while NYISO's single-state control area creates conflicts between federal and state jurisdiction. Lately, however, several New England states have raised jurisdictional questions. As the rate impacts of New England's transmission investment boom become more apparent, it remains to be seen whether FERC will be able to resolve federal-state (and state vs. state) conflicts.

[3] Localized Costs are costs associated with regional benefit upgrades that (in ISO-NE's determination) are not reasonable to be supported on a regional basis. Such costs could include, for example, the incremental cost of placing transmission lines underground when such construction is not justified on an engineering basis.

ISO-NE Proposed Criteria for Evaluating Requests for Economic Planning Studies
1. Consistent with regional goals
2. Provides new system information
3. Provides information related to planning and not market design
4. Leads to detailed study of specific market efficiency transmission upgrades
5. Driven by economics and not reliability

ISO-NE's Economic and Market-Driven Projects – Cost Allocation and Recovery

Under ISO-NE's tariff, proposed Market Efficiency Transmission Upgrades are upgrades where the net present value (NPV) of the net reduction in total production costs to serve system load exceeds the net present value of the carrying cost of the upgrade. The tariff further specifies that, in order to determine the net present value of bulk power system resource costs, ISO-NE will take into account analyses that consider other economic factors in illustrating the net cost to load with and without the transmission upgrade, such as locational capacity costs, congestion costs, and LMP impacts.

Pursuant to FERC Order No. 890, ISO-NE revised its existing RSP process to include a process by which ISO-NE stakeholders may submit requests for economic planning studies. ISO-NE has proposed the following criteria for evaluating those requests:

- Consistent with regional goals
- Provides new system information
- Provides information related to planning and not market design
- Leads to detailed study of specific market efficiency transmission upgrades
- Driven by economics and not reliability

Under these provisions, stakeholders may ask ISO-NE to initiate a needs assessment to evaluate any potential upgrades or investments that could result in one or more of the following:

- A net reduction of total production costs to supply system load
- Reduced congestion
- The integration of new resources and/or loads.

The revisions further include procedures for prioritizing requested economic planning studies, as well as allowing ISO-NE to initiate studies on its own as it deems necessary. Finally, the economic planning studies provisions incorporate the economic factors specified in other provisions for studying the potential of an upgrade to result in a net reduction of production costs.

ISO-NE's cost allocation methodology for market efficiency upgrades is the same as for reliability upgrades. Under the ISO-NE cost allocation mechanism, both Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades can receive recovery through the regional RNS rate. The mechanism also excludes from the socialized rate the portions of projects that are deemed to provide only "local" benefits.

There is a substantial ongoing effort to select the first set of economic planning studies to perform under the new provisions. Importantly, the current discussion includes a stakeholder effort to develop the analytical framework for these studies, including the criteria to be used and the specifics of the cost-benefit analyses to be applied. These criteria could include specific hurdle rates or benefit/cost ratios to determine whether projects should proceed as Market Efficiency Transmission Upgrades and receive regionalized cost recovery. But, in contrast to PJM, the New England approach seeks to use the economic planning process as a springboard to the broader discussion of linking transmission planning to environmental and public policy mandates. It is clear that some New England stakeholders and state policymakers expect an economic planning framework that will result in transmission built to meet public policy mandates for renewable and carbon-free resources. Other New England stakeholders and state regulators (notably in Massachusetts – half of the region's load), are strongly questioning the socialization of transmission developed pursuant to this framework. Whether such an economic-driven framework will allow development of this type of transmission as pool-supported upgrades with regional cost recovery remains to be seen.

While the New England RSP process has included an economic planning mechanism for several years, in practice there have been no projects developed and paid for pursuant to ISO-NE's economic mechanism. Moreover, increasing discontent over the rate impact of the New England transmission buildout casts significant uncertainty over the economic planning process. Benefit-costs tests may become significantly more stringent as a result of ratepayer revolt over the $7 billion of planned reliability upgrades. Perhaps most significantly, it may become increasingly difficult to argue for additional rate increases to fund transmission solely to access renewable resources which, although needed to meet public policy mandates (RPS, RGGI), are not needed to keep the lights on nor do they pass conventional (e.g., LMP or production cost based) benefit-cost tests.

As for market-based or merchant transmission projects, there is virtually no activity in New England. There are no proposed merchant transmission projects under development, and all of the developers of the proposed renewable transmission economic projects are seeking cost-based rate recovery. The only existing market-based transmission line in New England, the Cross Sound Cable, was driven by economic exports to the NYCA.

CANADA

New York's Canadian neighbors, Ontario and Québec, are of course outside of FERC's jurisdiction and mandates regarding transmission planning and cost allocation. Nonetheless, it is important to briefly review the state of transmission planning and cost recovery in these provinces to better understand the choices available in New York.

Ontario

Historically a winter-peaking control area, Ontario has seen its peak demand (now at around 27,000 MW) shift to the summer as its urban centers in Toronto and southern Ontario have grown. The challenges of this shift, together with stringent public policy mandates for the retirement of carbon-emitting generation and an aggressive and accelerated implementation of demand resources, are helping to shape the Province's protocols for transmission planning and cost allocation.

Ontario's hunger for power continues unabated, particularly in the summer peaking Greater Toronto metro region, which represents over 40% of the province's total load. The Ontario Power Authority (OPA) estimates that the province will need an additional 30,000-34,000 MW in new resources by 2025. The OPA serves as Ontario's long-term planner for transmission and resource adequacy, while a separate provincially owned entity, the Ontario Independent Electric System Operator, serves as the Province's system operator, spot market administrator, and overseer of short-term reliability (reliability coordinator).

Supply options to meet this load growth are increasingly being prescribed by government mandates as opposed to markets. The Ontario government has committed to retire all of Ontario's coal-fired generation in phases by 2014. Already retired and demolished is the 1,100 MW Lakeview plant in the Greater Toronto region, leaving over 6,400 MW of existing coal-fired capacity that has to be replaced under the provincial mandate.

Other Ontario government policy mandates include:

- Formal establishment of conservation as taking priority over supply resources and a mandate to reduce demand by 1,350 MW by 2010 and an additional 3,600 MW by 2025
- A limited increase in the amount of nuclear generation to a government-established maximum of 14,000 MW (present nuclear capacity is 11,000 MW)
- Increasing renewable resources to 15,700 MW from a present 8,200 MW
- Implementation of a "smart gas" strategy to use natural gas only for peaking resources and local area reliability needs in load centers, and increase these resources by as much as 6,000 MW by 2017.

Achieving these policy mandates will require significant investment in transmission, both in and into load pockets as well as long-haul transmission to access distant renewable resources. All of Ontario's electricity transmission system is owned and operated by Hydro One, the provincially owned transmission and distribution utility. Hydro One collects the costs of its bulk power transmission facilities via a Provincial Transmission Services (PTS) network service rate applicable to all transmission customers in the province. The PTS rate is effectively a postage stamp rate that socializes all of Hydro One's transmission costs across all customers, without regard to location.

Hydro One has several major transmission projects underway, including a 1,250 MW interconnection with Québec and a 112-mile 500 kV west-to-east transmission link between the Bruce nuclear station on Lake Huron and the Milton substation in the outskirts of the Greater Toronto region. The Québec interconnection will significantly increase imports from Québec; notably, Hydro-Québec has agreed to fund 85% (C$684 million) of the project's cost.

The Bruce-Milton line in southern Ontario will provide a key west-to-east link for future transmission to access renewables in the far western and northern regions of the Province. Specifically, the OPA has identified several transmission upgrades to access thousands of MW of hydro resources in far northern Ontario (particularly in the Albany and Moose Rivers) and wind resources in western and northern Ontario. Another source for extensive renewable resources is the Nelson River hydro development in far northern Manitoba, to the west of Ontario. Existing transfer capacity between Manitoba and Ontario is minimal (about 300 MW), and the two provincial governments are formally exploring the feasibility of a 1,500-2,000 MW interconnection. However, the distances involved and the difficulties of inter-provincial cost sharing may give an advantage to intra-provincial resources.

The concept of "enabler transmission lines" — transmission necessary to enable the development of remote clusters of potential renewable resources — is a significant driver of future transmission investment in Ontario. Ontario policymakers and Hydro One have expressed concern that the present regulatory framework and costing regime may inhibit the development of these enabler lines and the associated renewable resources. An extensive review of cost allocation policy for enabler lines is underway at the Ontario Energy Board, with options on the table ranging from socialization to generator interconnection treatment (i.e., generators pay).

Québec

Québec is a winter peaking, 33,000 MW peak load system that obtains most of its energy and capacity from an enormous hydroelectric system and an associated, equally enormous high voltage transmission grid. Hydro-Québec is an active participant in northeastern power markets via interconnections with Newfoundland and Labrador, New Brunswick, Ontario, New England and New York. Surrounded by a DC "moat," Québec's power system is asynchronous with the rest of the North American grid and is thus isolated from any disturbances in its neighboring control areas.

In the last decade, the Québec government restructured provincially owned Hydro-Québec (HQ) into functionally unbundled units for distribution (HQ Distribution), generation (HQ Production), and transmission (HQ TransÉnergie or HQTE). In contrast to Ontario, the Québec electricity system remains mostly vertically integrated within the HQ umbrella, with HQTE serving as the Province's transmission service provider, system operator, reliability coordinator, and transmission planner. Another difference from Ontario is that Québec does not operate an electricity market (real time or day ahead).

Québec has made a very large commitment to wind energy and HQ believes its water resources provide an ideal portfolio for balancing the intermittency of wind generation. HQ Production has continued to invest heavily in further development of waterpower resources in the Province, and HQ Distribution has begun an extensive RFP-based procurement program for long term contracts with wind resources.

From 2006 through 2008, HQ Production has added 986 MW of new hydroelectric capacity, and another 890 MW is under construction and expected to enter service in late 2011. HQ Production is studying an additional 4,500 MW of hydroelectric projects to be completed by 2015, including a massive complex on the Romaine River, which drains into the Gulf of St. Lawrence in eastern Québec.

As for wind resources, the Québec Energy Strategy calls for increasing installed wind capacity to 4,000 MW by 2015. To that end, HQ Distribution began an RFP process for purchasing wind generation and to date has conducted two solicitations. The first solicitation resulted in signed contracts to purchase 990 MW of wind power from projects being developed on the north side of the Gaspé Peninsula in southeast Québec. A second solicitation for an additional 2,000 MW has recently been completed, with 15 projects selected for a total of 2,004 MW and in-service dates ranging from 2011 to 2015. The capital outlay for this second round of projects is estimated at C$5.5 billion, including C$1.1 billion for transmission infrastructure.

To integrate all of these projects into the Québec grid as well as keep up with load growth in the urban centers of southern Québec, HQTE has embarked on a transmission capital expenditure plan of over C$5 billion through 2010. HQTE's rate structure is similar to Hydro One's in Ontario – a postage stamp regional rate for all network transmission service in the Province. All of HQTE's transmission costs are rolled into this rate, as regulated by the Québec Energy Board (the Régie de l'énergie).

4. Factors Influencing Large-Scale Transmission Expansion Within NYCA

Transmission expansion is driven by many factors and faces multiple hurdles. Most of these drivers and hurdles are common across several jurisdictions and power markets. However, the history and characteristics of the New York bulk power transmission system present additional drivers for (as well as obstacles to) transmission investment.

Importantly, several of these drivers reflect New York's policy choices for the future of its electric system. These policy choices effectively create new criteria and objectives for transmission planning in New York. It is increasingly clear, however, that the development of these new environmental and public policy mandates did not fully take into account the existing transmission planning framework.

Historically, transmission investment was driven by the need to deliver power from large generation projects to load. More recently, in the RTO/ISO era, transmission investment is driven primarily to maintain and enhance reliability, with some consideration of economic and market efficiency purposes. Looking forward, it appears that transmission may need to be planned to meet objectives other than reliability and economics – namely, public policy objectives driven by environmental and fuel diversity concerns. The incorporation of desired attributes other than system reliability and market economics represents a significant change for the transmission industry.

Reliability standards (originally voluntary but now mandatory under NERC with FERC oversight) have established the primary objectives for transmission planning in the last decade or so. In the early days of restructuring it was widely believed that preserving and enhancing reliability would be the only role for planning. Markets were expected to meet both resource adequacy and economic/market efficiency needs – areas where traditional central planning had resulted in expensive solutions and stranded costs.

The last few years have seen the resurgence of planning and the incorporation of economic and market efficiency considerations into the regional planner's scope. FERC's Order No. 890 requires (for the first time) the explicit inclusion of economic planning processes in transmission service tariffs. However, FERC clearly stated that is not ordering construction of transmission by means of this economic planning requirement.

The pace of integration of economic planning varies across the U.S., with some regions fully embracing economic objectives while others are expressing concerns on the grounds of potential market interference. Nonetheless, economic considerations — whether congestion reduction or overall participant costs — will continue to grow in importance in transmission planning. Projects that would not have passed reliability-based tests for inclusion in transmission plans (at least not yet, as many economic projects become reliability-driven as demand grows) may qualify under economic criteria and thus could be featured in several RTO/ISO regional transmission expansion plans in the next several years.

The various policy mandates being imposed on the electricity industry arise from the desire to create a new set of attributes for our electric energy; ones that may go beyond simply reliability and economics. But transmission upgrades driven by environmental and public policy reasons are typically not needed to 'keep the lights on' and will likely fail traditional cost-benefit analyses that focus on production costs (LMPs) and congestion/uplift costs. For example, transmission projects needed to develop renewable resources are often uneconomic because the resources are in remote locations, far from load centers and any other significant electric infrastructure.

To date, no transmission planning regime (reliability or economic) explicitly includes public policy objectives as essential goals for transmission planning. It is becoming harder to reconcile existing transmission planning frameworks with various public policy mandates being enacted by state (and possibly federal) policymakers. This missing link is particularly glaring with RTO/ISO planning frameworks, which generally lie under federal jurisdiction (FERC) but are applied in states that are enacting significant policy mandates on the electric industry with far-reaching implications on future infrastructure decisions.

Within the context of transmission planning as a public policy instrument, we have identified five (5) primary factors for large-scale transmission expansion in New York. Each factor's strength and ability to drive investment varies, but all play a significant role.

FACTOR #1: New York's Renewable Portfolio Standard and Its Implementation

In response to the 2002 State Energy Plan, which indicated an over dependence on fossil fuel generation, and a preliminary assessment from NYSERDA, which concluded renewable resources were compatible with the wholesale energy markets, the NYSPSC initiated a collaborative stakeholder proceeding to establish a renewable portfolio standard (RPS). On September 24, 2004 the NYSPSC issued its "Order Regarding Retail Renewable Portfolio Standard" (RPS Order) that established the NYSPSC's renewable energy policy, provided standards and definitions for "renewable resources" and identified compliance targets to ensure full implementation of the RPS. Implementing the RPS calls for an increase in the renewable energy used by retail consumers within the state from approximately 19% to 25% by the year 2013 via two pathways: 1) a centralized procurement approach and 2) a voluntary green market approach. The bulk of the increment will be realized via the centralized procurement implemented and administered by NYSERDA. Essentially, NYSERDA issues long term contracts awarded following a competitive procurement process whereby it agrees to purchase the renewable energy attribute or credit (REC) for each MWh generated by the eligible resources. The energy, however, must be consumed by retail load in New York. NYSERDA's pro forma RPS contract indicates that a supplier demonstrates this by providing monthly verification that the renewable energy was delivered to the NYISO Spot market.

Meeting New York State's 25% renewable energy mandate, however, may require building as much as 4,000 MW of nameplate wind plant capacity by 2013. Wind plants are also being developed in New York in order to sell energy as part of the renewable energy programs in place in neighboring states. Therefore, New York's wind plant capacity may eventually exceed 4,000 MW. The NYISO's interconnection queue currently contains interconnection requests for over 7,700 MW of wind plant projects. (See Figure 4-1)

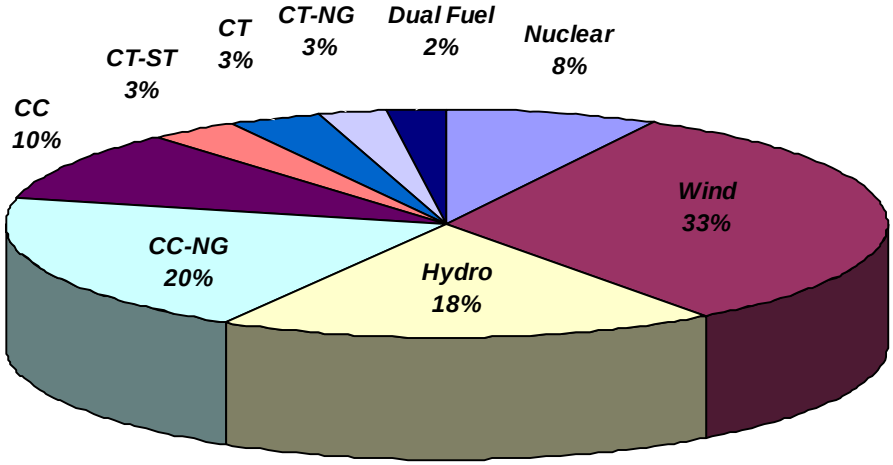

Figure 4-1: Proposed Generation Capacity – NYISO Interconnection Queue (8/28/08)

Building wind plants alone, however, will not achieve compliance with the State's RPS targets. Many of the proposed wind plants are seeking to interconnect in concentrated clusters located in the northern and western regions of the State. These regions' existing transmission network was not designed to deliver all the potential wind plant output to the loads in the southeastern portion of the State. NYSERDA's long-term contracts only provide revenue to wind plants that generate energy that is ultimately used to meet New York's retail load. Without investment in additional transmission infrastructure to balance and move wind energy to the load centers in the southeastern regions of the state, it may become difficult for New York to meet its state RPS targets.

It is not clear whether the present NYISO transmission planning framework will lead to the construction of transmission for renewable resources. Under New York's beneficiary pays approach, the beneficiaries on these renewable transmission lines would fund their development. But, identifying the beneficiaries of a long-haul transmission line designed to connect remote upstate wind resources to the downstate load centers may require a new equation. Is it the generators connecting to the new line? Or, are the customers in the load centers the primary beneficiaries? If the benefits accrue to both, how should cost responsibility be allocated between them? Should the beneficiaries be all customers in New York State, given that the RPS is a statewide mandate? These are difficult questions for which the present NYISO process does not provide answers — a topic that is addressed in Section V below.

New York is not alone in seeking solutions to the renewable transmission problem. In the United States, California and Texas have pioneered the linking of environmental and public policy mandates to transmission planning by creating mechanisms that allow the funding of transmission lines to connect renewable resources.

Under the California Independent System Operator's (CAISO) innovative "renewable trunkline" approach, the cost of transmission for renewable resources is initially included in the regional CAISO rate, with generation developers providing a reimbursement over time as they interconnect. Texas has designated Competitive Renewable Energy Zones (CREZs) and has ordered the construction of transmission between the CREZs and load centers to help meet the Texas RPS requirements, with cost recovery occurring via the regional Electric Reliability Council of Texas (ERCOT) rate. Separately, ISO-NE is using its economic planning approach to address the RPS and RGGI mandates of the six New England states. With 87 GW of wind resources in its queue, Midwest ISO is aggressively tackling new planning initiatives to develop transmission to deliver the Midwest's enormous wind resources. These examples of how other states and regions have been developing transmission for renewables are discussed in Appendix D.

FACTOR #2: Emissions Regulations

Another public policy driver for investment is generator emissions regulations. The toughening of limits for the emission of mercury (Hg), sulfur dioxide (SO2) and nitrogen oxides (NOX) has already had an impact on the Northeast's generation fleet, with virtually no new coal-fired generation installed in the last two decades. Starting in 2009, another generator emission will begin to be regulated — carbon dioxide (CO2) — under a cap-and-trade mechanism pursuant to the Northeast's RGGI. New York is the largest emitter of the ten states participating in RGGI.

RGGI was intended to stimulate federal action to control carbon emissions. Although several bills were introduced, the present session of the U.S. Congress failed to adopt a federal approach to carbon regulation. Nonetheless, there is growing public and political sentiment that carbon regulation must be implemented, and most observers expect some type of federal mechanism to be adopted in the next Congressional session.

As for emissions of Hg, SO2, and NOX, court decisions in 2008 have invalidated existing programs and have created significant uncertainty regarding the future structure of the regulation of these emissions. Observers expect that the new Congress will tackle a so-called "four-pollutant" (Hg, SO2, NOX and CO2) comprehensive emissions control bill, and there is a strong possibility that standards will be tightened considerably.

Increasing cost of emission regulations (whether via cap-and-trade allowances or other mechanisms) will increase the need to access resources that have emission attributes consistent with these policy mandates. While the U.S. as a whole may see a nuclear renaissance, the likelihood of new nuclear capacity being developed and built in New York, New England or Eastern PJM is very low. This leaves renewable and hydro, both of which are likely to require significant transmission investment, whether designed to deliver wind resources located in upstate New York, the Midwest, or Canada.

FACTOR #3: Improving Fuel Diversity

The increasing demand for natural gas in the Northeast is a concern to each of the three Northeast ISOs. The buildout of gas-fired plants in the last 15 years has resulted in a much higher exposure to the economic and physical interruption of natural gas supply.

In New York, fuel diversity statewide is very good, particularly in comparison to other regions, although natural gas's share of the statewide fuel mix is growing. Since 1990, the natural gas portion of New York's generation has almost doubled, from 17% to 33% of annual MWh produced. This growth came at the expense of oil-fired generation, which has declined from 26% to 6% since 1990. Improvements in combined cycle gas turbine technology, expansion of gas pipeline capacity and emission regulations have driven this switch to natural gas. (See Figure 4-2).

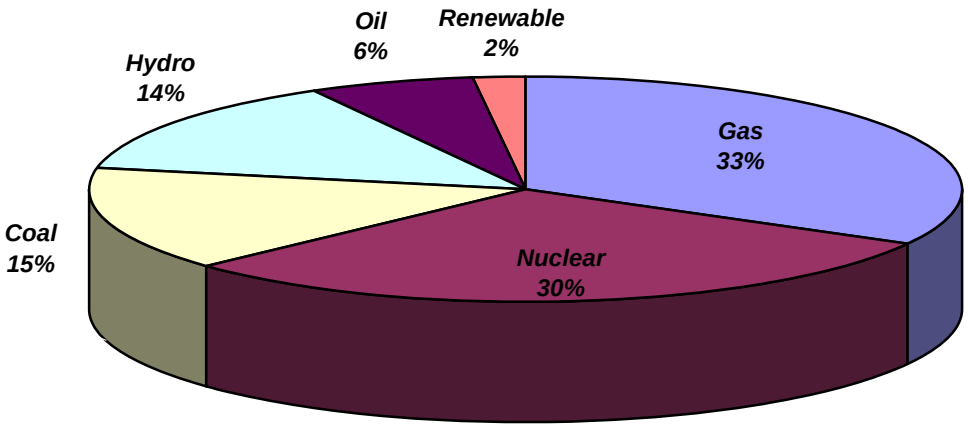

Figure 4-2: New York New Generation by Fuel Type, 2007

A closer look reveals less fuel diversity in the downstate load zones of Southeastern New York (SENY), where fuel diversity is a major concern. Natural gas-fired units produce 54% of the generation in SENY, as shown in Figure 4-3. Including oil-fired generation means that over two-thirds of the MWh produced in this region are subject to significant fuel price volatility. Transmission can provide significant fuel diversity benefits to this region by providing access to non-gas-fired resources located elsewhere.

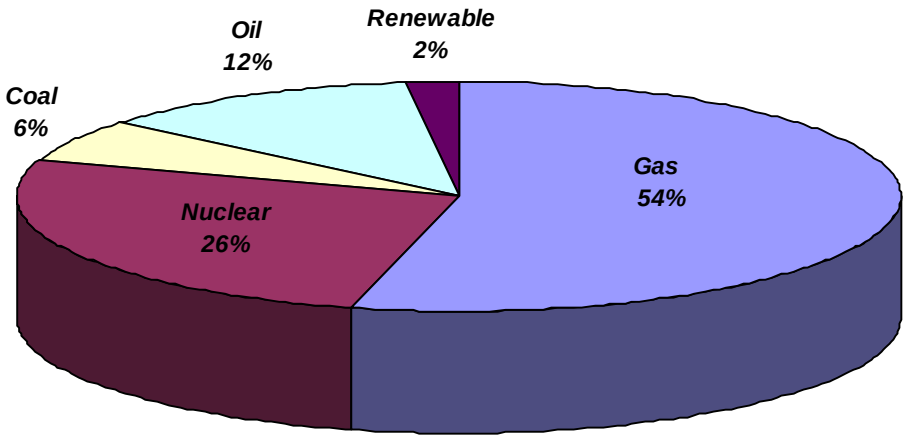

Figure 4-3: New York Net Generation by Fuel Type – SENY (Zones G-K) - 2007

Another concern is the effect of fuel diversity on LBMPs given that natural gas units are on the margin for most hours. In recent years, gas-fired units are on the margin for 65-70% of all hours in Zone F (Capital Region); as a result, gas prices set LBMPs for most hours during the year. Looking downstate to New York City, gas-fired units set the Zone J LBMP almost 90% of the time. The volatility of natural gas prices thus has a significant impact on average LBMPs for the year, and reducing this volatility may serve as a driver for investment, particularly for transmission into SENY. Transmission expansion alone, however, may not fully resolve this issue since for most hours in-city generation will likely remain the marginal unit.

The recent cancellation by NRG Energy of its proposed Huntley coal gasification and carbon sequestration project shows the difficulty in improving fuel diversity through alternate fuels. The 680 MW Huntley project would have replaced aging coal-fired generating units with an integrated gasification combined cycle (IGCC) facility with a carbon capture, liquefaction and underground storage facility. After winning a solicitation by NYPA for a utility-scale clean coal demonstration project, NRG cancelled the Huntley project after NYPA withdrew its support due to concerns over the project's cost, conservatively estimated at $1.6 billion. Had this project moved forward, it would have represented the first significant block of non-gas-fired generation in New York State in almost two decades.

FACTOR #4: Improved Inter-Regional Trade

In addition to the demand for renewable, low or no-emission, and non-gas-fired resources, the simple dynamics of inter-regional supply and demand can drive transmission investment. Transmission projects between regions, markets and/or control areas can provide immediate benefits to all the regions involved, not just to the "consuming" or importing region. Different control areas have different fuel mixes, technology mixes and load characteristics. This diversity reduces system risks and allows better optimization of grid resources

There are several examples of inter-regional cooperation regarding transmission projects. Local examples include:

- **New England/Hydro-Québec interconnection —** Initial development of this tie was driven by economic benefits to New England in the form of lower cost power and to Québec in the form of additional high-margin revenue from exports. Recently, however, as Québec's winter peaking system has experienced load growth, this intertie has had significant northbound flows during the winter months.
- **Second tie between New England and New Brunswick —** This recently completed project (called the Northeast Reliability Interconnection or NRI) was driven by the need to import lower cost New Brunswick power into New England and also by New Brunswick's winter peaking needs, particularly during the long-term outage of a major base load generation facility in New Brunswick (the Point Lepreau nuclear station).
- **Merchant transmission into New York City and Long Island —** The Cross Sound Cable and Neptune projects into Long Island and the Hudson Transmission Project and Linden VFT projects to New York City are clear examples of load serving entities in one region reaching out to another to obtain more competitively priced energy and capacity. While providing significant benefits to the importing region, these projects also provide real benefits to the exporting region by providing another path for reliability driven power flows.

While the need for inter-regional trade is a driver for transmission investment, it is complicated by the ever-present obstacle to most transmission projects — cost allocation. All inter-regional projects to date have had cost responsibility determined up front, whether borne mostly by one party (in the case of merchant transmission) or shared via elaborate agreements.

FACTOR #5: In-State Capacity and Energy Price Differentials

The "Demand Pull" from downstate load seeking lower cost capacity and energy is very strong, as evidenced by LIPA's and NYPA's long-term contracts for inter-regional transmission projects into Zones J and K. Sustained price differentials for both energy and capacity also have the capability of driving in-state transmission investment. The New York Regional Interconnection (NYRI) is an example of an in-state transmission project driven by upstate/downstate price differentials.

Yet, no major transmission lines between upstate and downstate New York have been built in more than 20 years. Cost allocation is the significant hurdle to this investment, as it has been for long before the existence of the NYISO. In the case of LIPA and NYPA, it was simpler (and quicker) to pursue and fund a new type of inter-regional transmission solution than to tackle in-state cost allocation issues. These entities were able to capture the benefits of their transmission projects by virtue of having captive customers and being able to enter into long term contracts. Additionally, neither project crossed a franchised utility's territory. Utilities will protect their franchise areas, a valuable and

exclusive asset, and are loathe to allow competitors' projects through their areas without some control and participation.

While congestion and energy price differentials can drive investment, they may be insufficient to support the development of a transmission project on market price differentials alone. Intra-pool point-to-point merchant transmission projects have failed to develop due in part to the uncertainties concerning price differentials after the construction of a project. Most projects will destroy the spread they are intended to capture by reducing congestion.

Capacity price differentials can serve as powerful drivers for transmission investment. The capacity price differential and the ability to use UDRs to claim out-of-state capacity as locational capacity in the NYCA provided a major component of the value proposition behind the merchant transmission projects into Zones J and K. This driver is also evidenced by the fact that the majority of new generation resources built since the initiation of the NYISO's wholesale markets has been in the downstate region, mostly the result of locational markets for both capacity and energy.

The NYISO's consideration of a locational capacity zone in the Lower Hudson Valley may serve to drive transmission investment between upstate and downstate, particularly if a tight linkage between locational capacity requirements and transmission planning is developed. Ultimately, however, the issue of upstate versus downstate cost allocation must be addressed before any such upgrades will proceed.

5. Potential Solutions for Internal Transmission Expansion in New York

Any viable transmission expansion solution for New York must resolve who pays for that transmission and, to the extent possible, ensure that it aligns with various commercial interests. There have been arguments over cost responsibility ever since the first long-haul transmission initiatives. The very nature of transmission projects creates the debate, as the primary beneficiaries of the project can often escape full cost responsibility and burden others with the project's financial and environmental/community impacts. The fear of protracted regulatory proceedings over this issue has discouraged transmission builders from even initiating multi-jurisdictional projects.

Restructuring of the electric industry and the implementation of competitive wholesale markets for power have significantly amplified the cost allocation debate, as industry participants comprehend how cost allocation decisions can either nurture or destroy market opportunities. After more than a decade of intense debate, some potential solutions are beginning to emerge.

The Cost Allocation Debate: Is Transmission a Competitor or an Enabler?

The debate over how to allocate the costs of the transmission grid is a part of a much larger philosophical divide between two opposite views of the role of transmission:

1) Transmission is a market product that competes with other solutions in the market
2) Transmission is an essential facilitator and enabler of competitive generation markets.

At the heart of this divide are divergent views over whether transmission is a natural monopoly. The answer to the monopoly question tends to dictate opinions regarding cost allocation.

Those who believe that transmission is a substitute for generation, and that it should be treated like all other options and solutions for meeting customer and power system needs, will likely advocate a beneficiary pays approach, under which cost responsibility is aligned with cost causation. Such treatment of transmission would place it on the 'level playing field' so often aspired to by free-market economists and policy makers.[4]

On the other hand, many believe that the real value of transmission is in enabling and improving competitive markets for generation, particularly when the strategic value and benefit far outweighs the cost of the transmission itself. The premise is that transmission is a public good, not a competitive product. For example, the interstate highway system has provided immense benefits to consumers in the form of increased competition for all

[4] Harvard's William Hogan has written extensively on market-based transmission; see, for example, *Market-Based Transmission Investments and Competitive Electricity Markets*, Center for Business and Government, John F. Kennedy School of Government (August 1999), available at Professor Hogan's website, www.whogan.com.

sorts of goods and services, benefits universally acknowledged to exceed the cost of building the interstate system. Likewise, transmission should be allowed to provide benefits in the form of enhanced competition for energy and capacity generation services.[5]

To further inflame the debate, geography and resource wealth can play a decisive role, often overriding philosophical opinions on electricity policy. For customers in a resource-poor load pocket, not having to pay the full freight of transmission improvements to relieve resource needs is understandably enticing. For fortunate regions with a wealth of excess resources, the cost allocation debate can be especially difficult as it exposes the tension between wishing to profit from the export of your resources and keeping costs to your native customers low. For those located geographically in between these two players, the challenge is in protecting their interests and their consumers from having to pay for investments not needed for local service. This issue has its parallel in the debate over open access and markets. Low cost states have eschewed competition in order to husband low cost resources such as coal and hydro and prevent them from being exported.

Intentionally or not, transmission creates winners and losers. New transmission pits those who need resources against those who have them. It creates confrontations between suppliers and consumers. Complicating matters tremendously is the diffuse nature of the benefits of transmission investment. Large transmission projects can shift bidding behavior, making predictions about price impacts difficult. Over the longer term, the cost and benefits identified with a transmission expansion can shift due to changes in fuel prices, population and economic growth as well as technology advancements. Historically, policymakers have struggled to identify the beneficiaries of transmission, and even when such identification is successful and agreed upon, regulatory and jurisdictional structure issues often prevent a fair allocation.

The Cost Allocation Debate: Beneficiary Pays vs. Socialization

New York has a long history of upstate versus downstate disputes over infrastructure, and transmission is a part of that history. Simply put, upstate interests typically do not want to host, and much less pay for, facilities designed primarily to serve downstate interests. Meanwhile, downstate interests are not willing to fund (and bear the cost recovery risk for) 100% of the cost of facilities located upstate. Projects that have circumvented this cost allocation roadblock, such as the New York State Thruway and NYPA's state-wide transmission network, were state-sponsored projects that will be difficult to repeat in today's political and siting environment.

A review of the distribution of transmission costs presently being recovered from New York consumers and the zonal distribution of the peak demand reveal potential reasons for this fraternal disagreement. Figure 5-1 presents the annual transmission revenue requirements for each New York transmission owner.

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[5] One of the more vocal exponents of this position has been National Grid – see *Transmission: The Critical Link*, available from National Grid at: http://www.nationalgridus.com/non_html/transmission_critical_link.pdf. See also Paul Joskow and Jean Tirole, "Merchant Transmission Investment," *The Journal of Industrial Economics*, Volume LIII (June 2005).

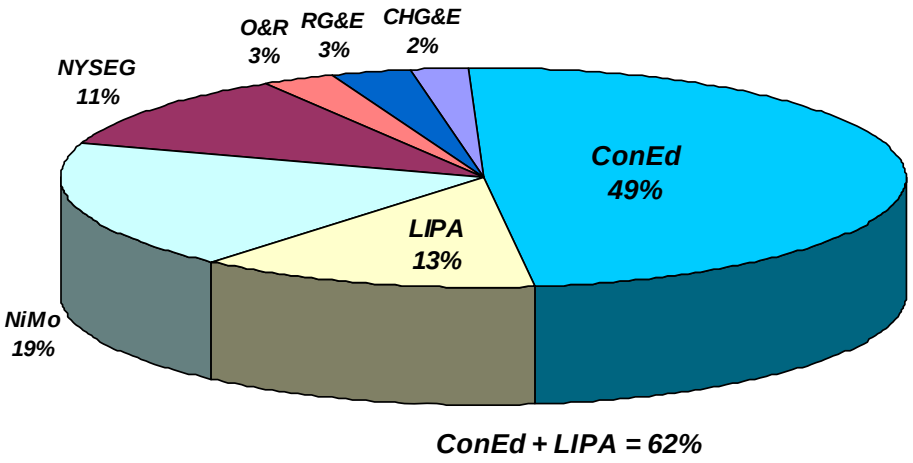

Figure 5-1: Annual Transmission Costs Recovered by New York Transmission Owners

Consolidated Edison's annual transmission revenue requirement represents almost one half of the New York State total, an amount that reflects the higher costs of building electric infrastructure in an urban environment. Including Long Island results in downstate transmission costs representing over 60% of the state's total. Figure 5-2 shows the zonal distribution to statewide summer peak demand.

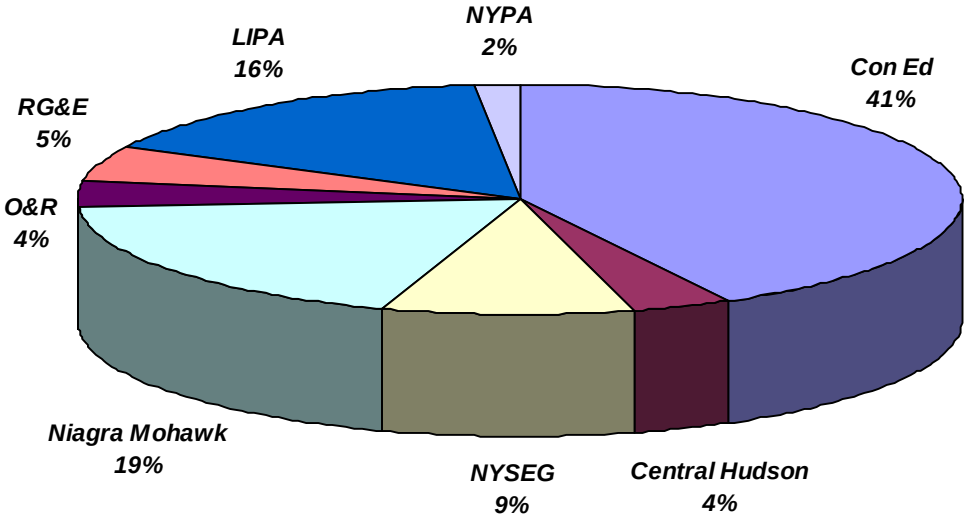

Figure 5-2: New York Control Area Forecasted Peak Load - 2008

A New York State transmission buildout of the same scale as underway in New York's neighboring ISOs — assuming that it can be justified, of course — will not take place until the cost allocation debate is fully addressed. As discussed earlier, how you view the role of transmission tends to form your opinion on the "right" cost allocation framework.

Pros and Cons of a Beneficiary Pays Approach

A beneficiary pays approach has many virtues, foremost of which is consistency with markets. By forcing those who benefit from transmission upgrades to pay for them, participant funding does not interfere with market-driven outcomes. Respecting and encouraging market outcomes are bedrock principles in New York, as NYISO's energy, reserves and capacity markets are among the most sophisticated and advanced in the nation.

The beneficiary pays principle is also consistent with long-standing regulatory principles regarding the assignment of cost responsibility to those that cause the costs to be incurred. Having cost responsibility follow cost causation is widely accepted to be the basis of appropriate ratemaking and regulatory treatment in New York and elsewhere.

Nonetheless, criticisms of the beneficiary pays approach abound. First among these is the so-called "passing the hat" issue — when potential beneficiaries are passed the hat and asked to contribute, few volunteer to do so. There is a fear of buyer's remorse since transmission expansion is a long term investment, but the long term benefits of the project are uncertain and, therefore, difficult to accurately identify.

Another problem is in the process for identifying beneficiaries. The fundamental premise behind a beneficiary pays or participant funding cost allocation framework is that the beneficiaries of the transmission investment can be identified and charged. This task has proven to be harder than it seems, notwithstanding complex mechanisms such as PJM's DFAX. As one transmission utility executive quipped, assigning beneficiaries is "too hard, my head hurts."

All transmission provides both reliability and economic benefits — even transmission identified as needed because of violations to reliability criteria. As a result, it can be difficult to identify beneficiaries. Are the economic and reliability beneficiaries the same? How should economic beneficiaries be defined — by decreases in production costs, LBMPs, and/or capacity prices? Should beneficiaries include entities that will profit from the sale of additional energy and capacity? Even if answers to these questions are available, they tend to change with time, particularly since transmission assets can have useful lives of up to 40 years or more. A region that did not initially see a benefit from a particular upgrade may one day end up being a significant beneficiary. For example the state of Maine opposed contributing to substantial bulk transmission upgrades to benefit the southern New England load centers because it has excess generation capacity. Maine's arguments were notably undermined when its abundant gas-fired generation was forced to shut down repeatedly last winter as a result of gas supply curtailments in Sable Island, Nova Scotia — the source of most of Maine's gas supply. ISO-NE quickly redirected power flows so that southern New England could keep the lights on in Maine, and the southern New England backbone transmission improvements were suddenly very useful to Maine.

Several philosophies and methods have been developed to address the identification of beneficiaries and are in place today. Most of these frameworks treat new and existing

transmission investments similarly. However, different treatments are evolving (for example, see PJM and Midwest ISO descriptions in Section 3 of this paper). The common thread these frameworks all share is that consumers always bear all sunk transmission costs, with generators funding some or all of the costs to connect their resources to the grid.[6]

Some have pointed to the creation of incremental financial transmission rights (such as TCCs) as a vehicle to fund transmission investment. Under this approach, the beneficiary of an upgrade would be willing to fund the project in order to receive incremental transmission property rights in return. As discussed earlier, however, the value of incremental transmission rights fully depends on the continued existence of a price differential. Should transmission expansion eliminate that price differential, the transmission rights are rendered worthless, leaving the participant that funded the expansion with no revenue to offset the cost of the upgrade. Further, changing market parameters, such as fuel costs, bidding strategies, technologies and market rules can cause congestion pricing to reverse. For example, when a new 345 kV transmission line was installed in Boston in 2007 the congestion costs went from positive to negative and the previously profitable financial transmission rights (FTRs) into Boston became a liability.

Most managers fear buyer's remorse, and do not want to run the risk of being second guessed if they agree to pay for transmission, but turn out not be the main beneficiary. Additionally, the possibility of a regulated solution can create a "moral hazard" that inhibits market-based investment. An entity that may have sufficient economic incentive to fund (on a beneficiary pays basis) a particular upgrade may still delay if it believes that there is a possibility that a cost of service solution may be available, or there will be another opportunity to shift the cost.

Pros and Cons of a Socialization Approach

Advocates of socialization point to it as the simple solution to the pitfalls of participant funding. Under a socialized, postage stamp approach, there would be no need to spend time and effort identifying beneficiaries. There is significant evidence that postage stamp approaches do encourage substantial increases in transmission investment — witness the ongoing transmission buildout in ISO-NE, PJM and ERCOT. And, as discussed earlier, socialization takes care of issues regarding changes in the use and flows on the bulk transmission system over time.

While some socialization advocates acknowledge the dulling of price signals to entrepreneurs as a result of socialization, the same advocates also strongly believe that transmission is an enabler of markets and not a market product. Thus, in this view abundant transmission capacity is a prerequisite to robust generation markets, and there is no such thing as "too much" transmission. There is little question that socialization

[6] In a few other countries, generators must pay a share of the sunk costs of the grid. For example, in Argentina generators pay the bulk of grid access charges, about 80% of total sunk costs. Similarly, in Norway generators are responsible for 54% of the sunk costs of the grid. However, most other countries levy 100% of transmission sunk costs on consumers.

provides a simple (albeit too crude to some) answer to the cost allocation debate. And once cost allocation is resolved, transmission investment blossoms — as we have seen in PJM and New England.

But the shortcomings of socialization are significant. Foremost is interference with market-driven responses and outcomes. Socialization also blurs the cost causation relationship between those that cause the need for upgrades and those that end up paying for it. Breaking the link between cost responsibility and cost causation tends to have undesired and unintended consequences, as incentives for investment are not properly aligned. Perhaps the best illustration of socialization's undermining of investment incentives in market mechanisms is its impact on locational energy and capacity price signals. Socialization of transmission removes the locational link between entities that benefit from expansions and those who pay for them. Under socialization, load serving entities in congested areas have little incentive to fund the full cost of upgrades to relieve congestion, as a socialized solution that requires only a fraction of their cost support may be around the corner. Even if that congested region represents 50% of the total pool on a load ratio share basis, it would rather pay 50% of the cost rather than 100%.

Socialization also masks and hides information regarding other system characteristics and needs from market participants that are in the position to invest in the system, as well as regulators who may need the information for effective policymaking. By rolling everything into a 'black box' postage stamp rate, no clear signals are provided as to where transmission investment should occur. For example, advanced technology innovations to provide voltage control, frequency regulation and other ancillary services may be needed in particular locations of the grid, but a socialized cost recovery scheme will tend to mask those locations and favor larger, "lumpier" solutions.

Finally, socialization and the belief that there is never "too much" transmission may increase the likelihood of ratepayers paying for facilities that may not be used or useful, as larger investments are able to be spread regionally over more load. While the potential for stranded transmission costs is also true for beneficiary pays approaches, it is highly unlikely that entities that fund upgrades would agree to do so if there was any probability that the upgrade would not provide the promised benefits.

Potential New York Solutions

While arguments over the fairness of divergent philosophies for allocating embedded transmission costs continue, it is the application of these methods to new transmission investment that is most productive. While the beneficiary pays approach may be the most equitable and least intrusive to the market, even the most sophisticated cost allocation methodology cannot be implemented without resolving the real and perceived business interests. Simply put, a load-serving entity, even one that is clearly the beneficiary, will not want to pay for a transmission project when the ownership benefits go to its competitor.

Shared Ownership and Joint Development

One potential solution to aligning business interests with the beneficiary pays approach may be in explicitly linking transmission ownership and cost recovery. In this manner, a vested interest is created — the entity whose load pays for the upgrade would also own the project and receive rate base treatment. Linking ownership and cost recovery is an institutional and contractual vehicle that facilitates incorporation of beneficiary pays approaches to developing and funding new transmission investment. Shared ownership models also have the benefit of facilitating cross-border/inter-control area projects by providing a way to solve inter-regional cost allocation issues.

Shared ownership has a critical prerequisite — the entities involved must have a mutual interest in the benefits arising from the project. Finding shared interest in transmission investments that benefit both upstate and downstate New York has been problematic. Moreover, the NYISO's ability to create this mutual interest is significantly limited. The NYISO's CRP and its operating agreements with the New York Transmission Owners provide the NYISO with little authority to create this shared interest.

The FERC has strongly encouraged the joint ownership model in several forms, both in the context of individual transmission projects and in the formation of stand-alone transmission companies (transcos). At first, FERC required a significant degree of independence from market interests in the governance of these institutions; that is, independence from any generation ownership. Over time, however, FERC has relaxed its stance on independence, and has allowed affiliates of generation-owning vertically integrated utilities to participate in transmission companies.

Notably, under FERC's incentive ratemaking policies (Order No. 679) transcos can qualify for significant rate incentives, including return on equity (ROE) bonuses, accelerated depreciation, recovery of construction work in progress, and assured recovery of abandoned project costs. Utilities and transmission companies across the country have applied for and received FERC approval for some of these incentives, including AEP and Allegheny for their massive 500 kV and 765 kV PJM backbone projects.

FERC Order No. 679 established the following incentives for transmission investment:

- Higher rates of return on equity (ROE);
- Full recovery of prudently incurred construction work in progress (CWIP);
- Full recovery of prudently incurred pre-operations costs;
- Full recovery of prudently incurred costs for transmission facilities that must be abandoned or cancelled;
- Use of hypothetical capital structures;
- Accumulated deferred income taxes for transcos;
- Adjustments to book value for transco sales and/or purchases;

- Accelerated depreciation;
- Deferred cost recovery for utilities with retail rate freezes that preclude the pass through of costs related to new transmission investments; and
- Higher ROE for utilities that join and/or continue to be members of transmission organizations, such as (but not limited to) RTOs and ISOs.

There are several recent examples of joint ownership for transmission development. These examples can be characterized into three models:[7]

1) Joint ownership of transcos;
2) Joint ownership in a shared transmission system; and
3) Joint ownership of individual transmission lines/projects.

Shared Ownership in a Stand-Alone Transmission Company or Transco

Two of the several transcos in existence in the U.S. are the result of existing transmission owners spinning off their assets into a new jointly owned entity — American Transmission Company LLC (ATC) and Vermont Transco LLC (VT Transco), managed by Vermont Electric Power Company (VELCO). Both of these entities are jointly owned by the transmission owners that transferred their assets, and ownership interest percentages are determined by assets contributed or by load ratios.

ATC was formed in 2000 when Wisconsin's four investor-owned utilities transferred their transmission assets at net book value to the new entity pursuant to state legislation. In return, the utilities received ownership interests in proportion of the value of the assets transferred. Wisconsin's joint public power agency joined as a fifth member by contributing cash to the venture and receiving, in return, an ownership share based on the agency's share of load in Wisconsin. Since its founding, ATC has added more than 20 members who have contributed transmission assets and/or cash to receive an ownership share in the company. Presently, ATC has 28 contributing owners and $2.2 billion in transmission assets, providing service to most of Wisconsin, the upper peninsula of Michigan, and portions of Minnesota and Illinois. Since 2001, ATC has invested over $1.7 billion in new transmission facilities, and approximately $2.8 billion in additional investment is planned over the next 10 years. ATC is a member of Midwest ISO and recovers its costs through the Midwest ISO tariff's license plate rate mechanism.

VT Transco is the latest form of VELCO, originally created by Vermont's investor-owned utilities in 1956 to deliver power from the St. Lawrence River hydroelectric facilities across throughout Vermont. Over the years, VELCO's role evolved to include several municipal and public power agencies, to become the owner of all transmission assets in the state, and to develop an interconnection with Hydro-Québec. In 2006, VT Transco was formed as an LLC to own the Vermont high-voltage electric transmission system, and VELCO serves as the managing member of the LLC. Members in the LLC

[7] The discussion of the three shared ownership models is derived from the American Public Power Association (APPA) white paper, *Joint Ownership of Transmission*, issued January 2006.

include all of Vermont's investor-owned, municipal and cooperative utilities and have ownership shares proportional to their share of total Vermont load. VT Transco has invested over $200 million in new transmission since 2004, and is planning another $340 million in new transmission investment. VT Transco is a participating transmission owner in ISO-NE and recovers its costs through the ISO-NE tariff's RNS and LNS rate mechanisms.

Ownership in Shared Transmission System

There are several examples across the country where utilities have combined their transmission facilities to operate them as a single system. These joint transmission systems are not transcos, as participating utilities retain ownership over their facilities, but the combined system is operated, planned, and expanded as a single transmission system.

Examples of this arrangement include:

- Cinergy, Wabash Valley Power Association and Indiana Municipal Power Agency. These entities share an integrated transmission system that covers most of Indiana and parts of Ohio and Kentucky. Midwest ISO operates this system as a single entity, and forwards to Cinergy the transmission revenue collected for use of the system. Cinergy in turn forwards the share of revenue to the two other participating entities. The three utilities jointly plan for upgrades and expansions, and assign ownership of specific additions among the three utilities in proportion to each utility's percent of total load.
- The state of Georgia's transmission system is operated as a single system by Georgia Power (Southern Company) but is actually owned by four utilities (Georgia Power, Oglethorpe Power, MEAG Power and Dalton Utilities). Each utility owns its facilities and is responsible for operation and maintenance costs of its owned facilities. Through a joint planning process each owner maintains an investment in transmission that is in parity with the investments of the other joint owners, as determined via a load ratio share mechanism.
- Otter Tail Power, Great River Energy, and Missouri River Energy Services. These entities share an integrated transmission system that covers parts of Minnesota, North Dakota, South Dakota, and Iowa, all under the Midwest ISO's operating authority. As in the examples above, each utility owns its transmission assets and investment is generally maintained in proportion to each utility's share of load in the system's service area.

Joint Ownership in Individual Transmission Projects

A nearby example is the New England/Hydro-Québec Interconnection, developed in two phases in the late 1980s by subsidiaries of New England Electric System, now National Grid. While the National Grid subsidiaries are the owners of the facilities, the projects would not have been developed without a joint use agreement with several New England utilities and public power agencies. These load serving entities do not own the

project, but in return for supporting its costs receive a percentage share of the interconnection's transmission rights.

In Texas, several joint ventures are pursuing development of CREZ-related transmission projects selected by the PUCT. These partnerships include companies formed by Oncor Energy Delivery (formerly TXU), AEP and Berkshire Hathaway's MidAmerican Energy Holdings.

In the Western States most of the joint development of transmission projects has involved state and federal public power agencies as a result of the prominent role of state and federal public power in the Western grid. Examples of joint ownership in the West include:

- **Arizona.** Several bulk transmission lines built as part of the Palo Verde nuclear plant and the Navajo coal-fired generating station were developed and are owned by several public and private entities including Arizona Public Service (APS), Salt River Project (SRP), Public Service of New Mexico, El Paso Electric, Los Angeles Department of Water and Power (LADWP), the U.S. Bureau of Reclamation, Tucson Electric Power, and Nevada Power.
- **California-Oregon Transmission Project (COTP).** Completed in 1993, the COTP is a 340-mile 500 kV line that connects the Bonneville Power Administration system in southern Oregon to central California. The project was developed by the Transmission Agency of Northern California (TANC) a joint power agency owned by 15 municipal and public power agencies in California.
- **Green Path.** Green Path is a joint venture between California public power utilities LADWP, the Imperial Irrigation District (IID), and Citizens Energy Corporation, a Boston-based non-profit energy services company. The Green Path project is a collection of upgrades that features several hundreds of miles of new 500 kV and 230 kV lines in southern California, including several new interconnections with the California ISO system. Green Path is also partnering with the Southern California Public Power Agency for the northern portion of the project and with three Arizona utilities (including APS and SRP) for the eastern portion extending to Arizona. Phase I of the project is presently undergoing permitting.
- **Path 15.** Path 15 in California refers to one of the most constrained transmission interfaces in the Western Interconnection — a pair of 500 kV lines connecting northern and southern California. The 2001 National Energy Policy recommended that DOE authorize its Western Area Power Authority (WAPA) to explore ways to relieve the Path 15 bottleneck. As a result, WAPA solicited proposals from non-federal entities to participate in the construction and ownership of transmission upgrades to Path 15. The project envisioned was an 84-mile 500 kV line to serve as a third circuit to provide an added 1,500 MW in the south-to-north direction. WAPA entered into a joint agreement with Trans-Elect — an independent transmission company — and PG&E, under which WAPA served as project manager, completed all planning work, acquired land rights, and managed the construction of the project. The agency also owns and

maintains the transmission line, and retains a 10% share of the transmission rights over the facility. Construction was completed in December 2004, ahead of schedule. The total project cost of $250 million came in well under the original cost estimate of $306 million. The project's cost-of-service based revenue requirement is included in the CAISO FERC-approved network service rate.

Issues that need resolution before joint projects can proceed include responsibility for construction, operation and maintenance (for example, determining who builds/maintains the line if it crosses multiple service areas). Typically, these issues are addressed by the ownership splits, and can be as simple as "you build/maintain in your area and I do it in mine." In the eastern RTOs (PJM, ISO-NE), the RTOs designate specific TOs to build and maintain the portions of planned projects located in their service territories.

One point of caution that should be acknowledged regarding the designation of incumbent transmission owners to build in their service areas is the impact of such designation on market-based and merchant transmission. Allowing only an incumbent transmission owner to build and maintain facilities within a given footprint will chill if not eliminate entrepreneurial transmission (and possibly generation) responses in that area. A method for resolving this issue is provided by Texas, where there is wide-open competition for the construction of CREZ-related upgrades and the PUCT will make the selection via a competitive solicitation process.

Other Potential Solutions Consistent with a Beneficiary Pays Approach

Absent shared interests and an upfront allocation agreement, the cost allocation obstacle must instead be resolved through leadership in policymaking. Without a broad-based policy determination regarding cost allocation for large-scale projects, these projects will simply not move forward. There are several challenges in developing such a policy rulemaking, foremost of which would be the jurisdictional question of whether the NYSPSC or FERC has ultimate jurisdiction over transmission costs in New York. This is a legal matter outside the scope of this paper, but it is clear that any long-lasting policy on allocating new transmission costs among multiple New York transmission owners will require acceptance by both agencies.

Once jurisdictional issues are addressed, the policy rulemaking on cost allocation would turn to equally vexing issues regarding the criteria for determining the benefits of transmission projects as well as who the beneficiaries of such projects are. This effort provides an opportunity to incorporate public policy mandates such as the New York RPS, RGGI, EEPS, and fuel diversity objectives into the planning process. Mechanisms to identify beneficiaries could rely on these public policy mandates for support. While some may be concerned that this approach is simply a path to socialization, it is in fact consistent with a beneficiary pays method since policy considerations may determine that all New York State ratepayers will be beneficiaries over the lifetime of the facilities.

One solution that may be too controversial is to rely on the state power authorities to be the builder of last resort. The state has already relied on NYPA to provide energy infrastructure on a fast-track basis in response to concerns over power shortages in the

New York City metropolitan area. A permitting process that could take as long as two years was streamlined to 10 months in order for NYPA to install, by summer 2001, a total of 450 MW of small gas-fired peaking plants at six sites in New York City and one on Long Island.

The one exception to New York's license plate rate structure is the recovery of NYPA's costs, which are socialized across all New York transmission users via the NYPA Transmission Adjustment Charge (NTAC). One possibility is to use NYPA as a vehicle for regionalizing costs of projects determined to provide benefits to all New York ratepayers.

Finally, a recently filed approach to cost allocation under development in the Southwest Power Pool (SPP) may provide a new way of addressing the winners and losers created by transmission projects. Under SPP's "Balanced Portfolio" mechanism, economic transmission upgrades would be grouped into "portfolios" expressly designed to provide a net benefit to each SPP load zone. SPP would also have considerable discretion to force a "balance" of net benefits to each zone over time. Projects in approved Balance Portfolios would be eligible for regional rate recovery. By ensuring that all zones benefit from the economic upgrades, the issue of cost allocation becomes less of an obstacle to economic upgrades.

6. Conclusions

Review of the transmission planning and market mechanisms of the NYISO and its neighbors, the factors that influence transmission investment and the ongoing buildout of transmission in the Northeast, and potential solutions to increasing transmission investment in New York State yield several important conclusions.

- **The transmission expansion boom in PJM and ISO-NE is driven by the reliability planning processes in these control areas.** The resolution of expected violations of reliability criteria (both NERC and ISO-established) forms the principal basis for the billions of dollars in transmission investment in the neighboring RTOs' regional system plans. While both areas have existing economic planning processes, these protocols have not resulted in any substantial investment.
- **The existing contractual relationship between the NYISO and the NYTOs limits the ability of the NYISO to promote a transmission buildout as compared to PJM and ISO-NE.** Under the NYISO/TO Agreement the NYISO is limited in its authority to direct the modification or expansion of the transmission system. While the CRPP and the corresponding Supplemental NYISO/TO Agreement, recently submitted to FERC for approval, confers upon the NYISO the authority to trigger a TO's regulated backstop solution, its ability to direct the development of transmission upgrades remains substantially limited and is significantly less than its ISO counterparts in PJM and New England.
- **The NYISO CRPP is unlikely to facilitate a large-scale transmission buildout in New York State of a magnitude similar to its neighbors.** The NYISO's reliability planning process differs fundamentally from its PJM and ISO-NE counterparts. The NYISO CRPP looks at all resources – generation, transmission and demand resources – for solutions, and places a much higher reliance on market solutions for resource needs. As found in the latest CRP, market solutions are proposed and being developed to fully meet reliability needs identified through 2013. The CRPP's all-source nature, its preference for market solutions, and the compression of the timeframe for regulated backstop solutions make it less likely that transmission will be chosen as a solution to address reliability needs in New York.
- **The NYISO CSPP and its economic planning component, as proposed, may facilitate substantial transmission investment, but this will depend on the modeling protocols and the cost/benefit metrics currently under development in the NYISO's stakeholder working groups.** It is too early to tell whether the CARIS process will succeed in encouraging a significant increase in transmission investment, as its full scale implementation will not begin until summer 2009. Implementation of the CARIS process with its beneficiaries pay principle, in conjunction with the various New York State energy and environmental policy initiatives (*e.g.*, RPS and RGGI), may provide the vehicle to facilitate significant economic transmission investment in New York.

- **Inter-regional transmission development could significantly affect New York State, and New York must actively participate in related forums and processes.** As a natural sink for many inter-regional trade initiatives (and also a potential source should upstate renewable resources be fully developed), New York must remain involved in these discussions and in the development of any inter-regional cost allocation mechanisms.

While PJM and ISO-NE clearly view transmission as enablers of competitive wholesale energy markets, it is equally clear that the NYISO and its stakeholders view transmission as an equal competitor to generation and demand response. Market participants and stakeholders that view transmission as a market product that competes with other solutions to provide system needs will consider the NYISO planning process as a successful initiative that properly encourages and respects market outcomes. The potential economic and environmental benefits of new transmission investment, however, have not yet been realized in New York.

APPENDIX C

ONGOING AND RECENTLY COMPLETED MAJOR TRANSMISSION PROJECTS IN NEW ENGLAND

New England has made significant progress in improving its bulk transmission system, with almost $3 billion in new transmission investment added since 2002 and expected to enter service by year end 2008.

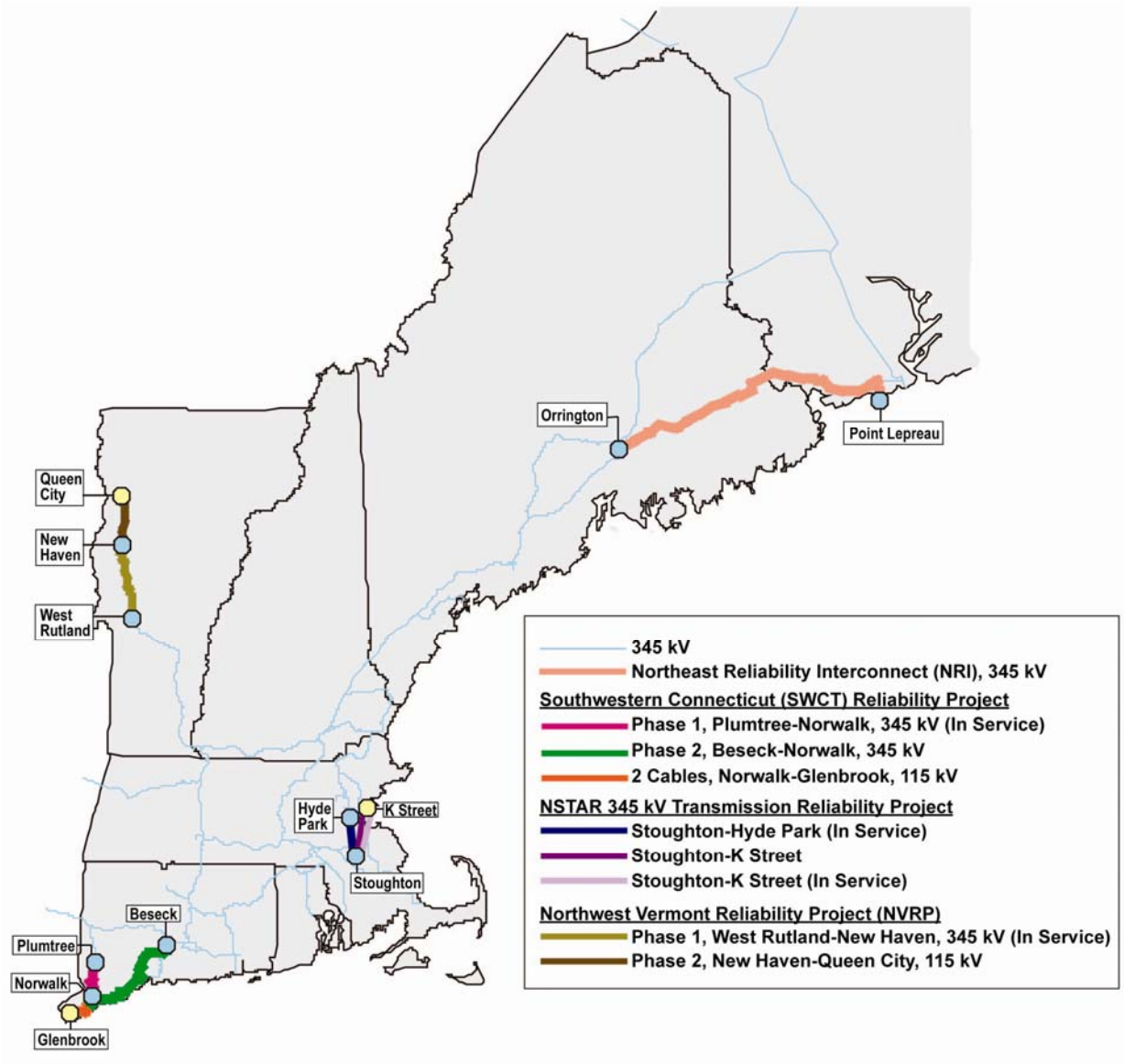

Figure C-1: Major New England Transmission Projects Under Construction, 2006-2007

Major projects under construction or completed recently include the following:

- Northeast Reliability Interconnect (NRI) – The NRI is a new 144-mile, 345 kV transmission line connecting the Point Lepreau substation (and nuclear plant) in New Brunswick to the Orrington substation in northern Maine. Approximately 84 miles (about $144 million) of the NRI are in Maine, and it represents the second bulk transmission system tie between New England and New Brunswick. The NRI increased transfer capability from New Brunswick to New England by 300 MW (to a total of 1,000 MW) and entered service in December 2007.
- Northwest Vermont Reliability Project (NVRP) – The $288 million NVRP consists of a package of new transmission lines, phase-angle regulating transformers (PARs), dynamic voltage control devices, and other equipment designed to address load growth in and around Burlington, Vermont. The NVRP includes: (1) a new 36-mile 345 kV line between the West Rutland and New Haven substations that entered service in January 2007; (2) a new 28-mile 115 kV line between the New Haven and Queen City substations that is under construction and expected to enter service by December 2008; and (3) several PARs and dynamic voltage-control devices, all with planned in-service dates through 2008 (one of three PARs entered service in December 2006 at the Blissville substation).
- NSTAR 345 kV Transmission Reliability Project – The $317 million NSTAR 345 kV project increases import transfer capability into the NEMA/Boston load pocket by approximately 1,000 MW. The project included the construction of a Stoughton 345 kV station and the installation of three new underground 345 kV lines between Stoughton and K Street substation in Boston. The first of these lines, an 11-mile cable between the Stoughton and Hyde Park substations, entered service in October 2006. The other two lines are 17-mile cables between the Stoughton and K Street substations. One of the Stoughton-K Street cables entered service in April 2007 and the second one is scheduled for installation and energization by summer 2009.
- Southwestern Connecticut (SWCT) Reliability Project – The two-phase SWCT project addresses one of the Nation's most notorious load pockets. The $357 million Phase 1 of the project consists of a new 20-mile 345 kV line between the Plumtree and Norwalk substations. Phase 1 entered service in October 2006. The $1.427 billion Phase 2 of the project includes a 70-mile 345 kV line circuit from a new Beseck substation (near Middletown, CT) to Norwalk and is planned to be in service in December 2009. The project also includes a pair of new 115 kV cables from Norwalk to Glenbrook estimated to cost $234 million. Together with Phase 2, the two new cables will increase transfer capability across the Norwalk/Stamford interface by up to 400 MW. Construction of the Glenbrook cables began in October 2006 and the cables are expected to enter service in December 2008.

Collectively, these four projects represent over $2.7 billion in investment. But, ISO-NE's RSP process continues to identify more needed transmission upgrades. Two recent additions to the ISO-NE RSP stand out as a result of their size, scope and cost.

New England East-West Solution (NEEWS)

ISO-NE and the New England transmission owners have identified a package of projects to comprehensively address several issues affecting Connecticut, Rhode Island, and the Greater Springfield area in western Massachusetts. Referred to as the New England East–West Solution (NEEWS), the projects are designed to increase transfer capability across the East-West interface in New England, which would include a significant upgrade to the transfer limit on power imports into Connecticut from Massachusetts and Rhode Island.

The two transmission owners involved, National Grid and Northeast Utilities (NU), have developed four specific upgrades that comprise the NEEWS project, with a total cost of at least **$1.6 billion**:

- Rhode Island Reliability Project – This project consists of a second 345 kV line between the West Farnum and Kent County substations in Rhode Island, to be built by National Grid and is estimated to cost $170 million.
- Interstate Reliability Project – A new 345 kV line between the Millbury (MA), West Farnum (RI), Lake Road (CT), and Card (CT) substations, with a total estimated cost of $354 million. The Massachusetts and Rhode Island sections would be built by National Grid and the Connecticut section by NU.
- Greater Springfield Reliability Project – This project consists of: (a) a new 345 kV line between the Ludlow (MA), Agawam (MA), and North Bloomfield (CT) substations; and (b) a package of extensive 115 kV line reinforcements and substation upgrades in the vicinity of Springfield, MA. The projects will be built by NU at an estimated cost of $714 million.
- Central Connecticut Reliability Project – A new 345 kV line between the North Bloomfield and Frost Bridge substations in Connecticut, to be built by NU at an estimated cost of $353 million.

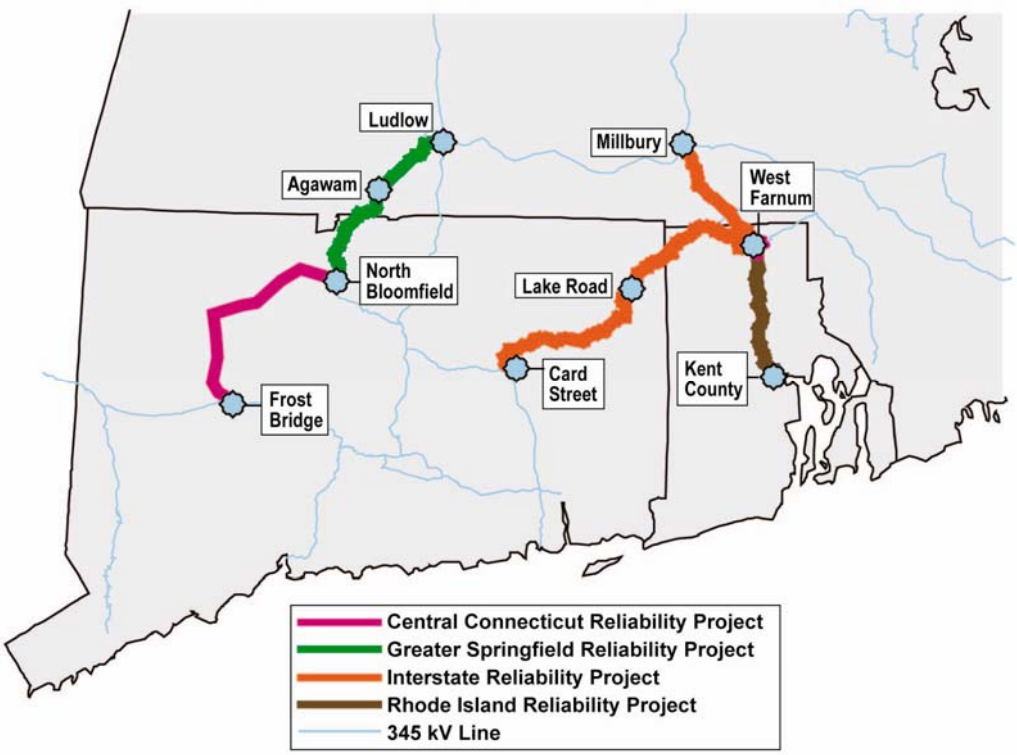

Figure C-2: New England East-West Solution (NEEWS) Project

In addition to the NEEWS projects above, the analyses that led to the NEEWS projects had spawned an additional 115 kV reinforcement project already underway in Rhode Island – the Greater Rhode Island Transmission Reinforcements, consisting of $185.1 million of improvements to National Grid's 115 kV system in Rhode Island and neighboring Fall River, MA. While not formally included in the NEEWS project cost, the Greater RI 115 kV reinforcement project results in a total of almost **$1.8 billion** in transmission investment identified by the NEEWS analyses.

The NEEWS projects have been formally included in the ISO-NE RSP with in service dates ranging from 2012 to 2013. Siting applications have yet to be made, as well as applications to ISO-NE to determine cost allocation for the projects (although ESAI expects the developers to seek full cost recovery via the postage stamp Regional Network Service (RNS) rate).

Maine Power Reliability Program (MPRP)

The Maine bulk power transmission system faces performance issues and relies on several Special Protection Systems and relaying schemes. The system is a high-loss system as it includes several relatively long 115 kV lines. In addition, the system has limited 345/115 kV transformation. A defining characteristic of the system with respect to the regional New England transmission network is a significant bottleneck in central Maine. While there are two 345 kV ties to New Brunswick and several 345 kV ties to New Hampshire, the central (mid-coast) portion of the state has only one 345 kV path (Orrington-Maxcys-Maine Yankee).

To address these issues, Central Maine Power (CMP), Bangor Hydro Electric (BHE) and ISO-NE have developed a package of extensive 345 kV and 115 kV improvements (dubbed the MPRP) that come close to rebuilding Maine's entire bulk power transmission system. The centerpiece of the project is an additional 345 kV circuit between the Orrington and Surowiec substations, thus eliminating a significant bottleneck in mid-coast Maine.

The package of upgrades can be grouped into the following clusters of projects:

1. BHE 115 kV upgrades
2. CMP upgrades
    a. Northern
    b. Southern
3. Public Service Company of New Hampshire (PSNH, part of NU) upgrades

<u>BHE 115 kV Upgrades</u> – These upgrades primarily consist of reratings and reconductorings, as well as the addition of capacitor banks. A cost estimate for these reinforcements is not available, but ESAI estimates the cost at $50 to $100 million.

<u>CMP Upgrades – Northern</u> – CMP evaluated several alternative packages of 345 kV and 115 kV upgrades between Orrington and Surowiec, but ultimately selected a package of projects that included:

- Four new 345 kV lines (Orrington - Benton (via Detroit), Benton - Maxcys, Maxcys - Gulf Island, Gulf Island – Surowiec)
- Several new 115 kV lines (Orrington - Maxcys, Winslow - Benton, Maxcys - Highland, Gulf Island - Lewiston Lower, Gulf Island - Livermore Falls, Livermore Falls - Riley, Riley - Rumford Paper)
- Rebuild several existing 115 kV lines (Bucksport – Belfast, Benton – Maxcys)
- Expand 13 existing 345 kV and 115 kV substations
- Two new 345/115 kV substations
- Five new 115 kV capacitor banks.

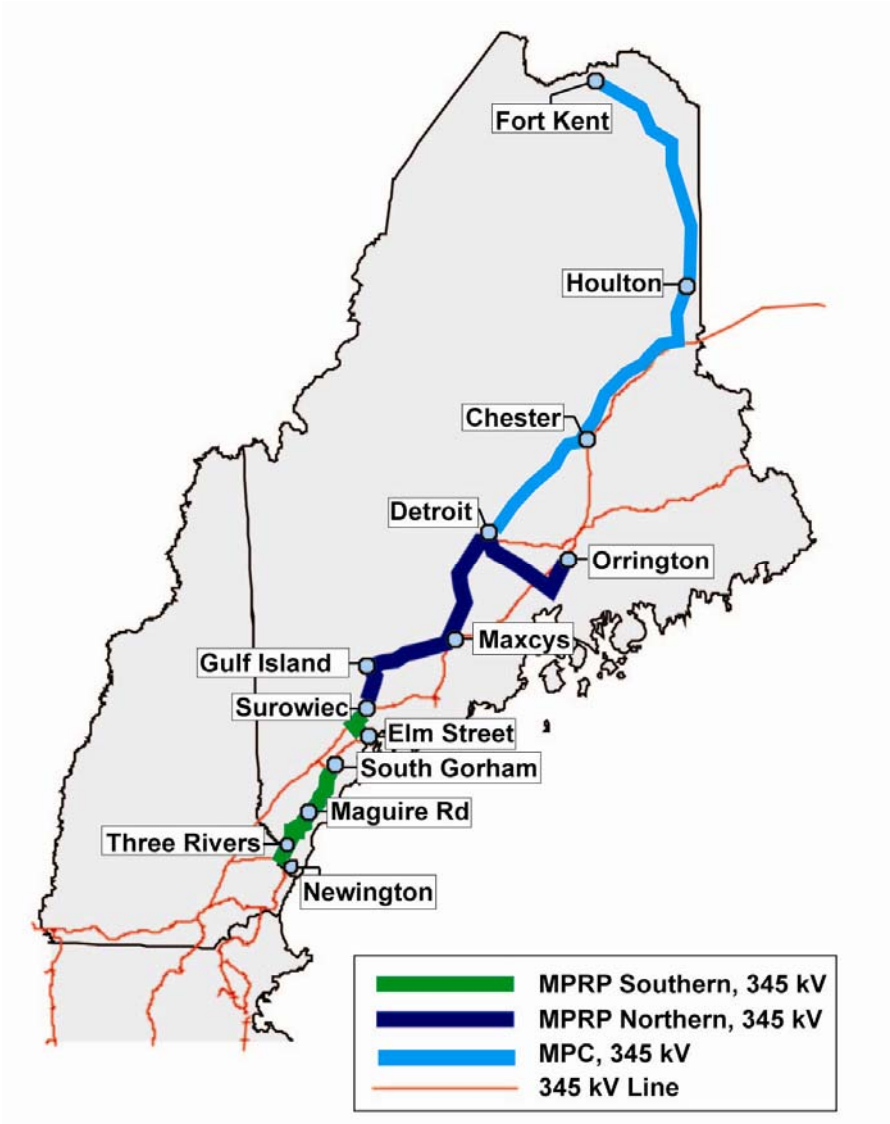

Figure C-3: Maine Power Reliability Program (MPRP) and Maine Power Connection (MPC)

The total cost of the CMP Northern upgrades is estimated at $1.0 billion.

CMP Upgrades – Southern – The selected package of 345 kV and 115 kV upgrades from Surowiec to New Hampshire (Newington) includes the following projects:

- Three new 345 kV lines (Surowiec - Elm Street, South Gorham - Maguire Road, Maguire Road - Three Rivers (ultimately terminating at PSNH's Newington substation))
- Two new 115 kV lines (Elm Street - East Deering, East Deering – Cape)
- Expand five existing 345 kV and 115 kV substations
- Build two new 345/115 kV substations

The total cost of the CMP Southern upgrades is estimated at $353 million.

PSNH Upgrades – PSNH's upgrades are related to extending and terminating the CMP 345 kV at PSNH's Newington substation, including the crossing of the Piscataqua River between Maine and New Hampshire. The PSNH portion of the upgrades is estimated to cost $70 million.

In total the MPRP includes over 350 miles of new transmission lines at an estimated cost of approximately **$1.5 billion**. This investment will significantly increase transfer capability across several Maine transmission interfaces that presently limit flows of Maine generation and New Brunswick imports to load centers in southern New England. Specifically, the MPRP will increase the Orrington-South interface from a present 1,200 MW to 1,975 MW, and the Maine-NH interface from 1,700 MW to 2,450 MW.

In July 2008, CMP and PSNH filed applications for a siting certificate from the Maine Public Utilities Commission (PUC). BHE has yet to make a filing but is expected to do so soon. Applications to ISO-NE to determine cost allocation for the projects have yet to be filed, but ESAI expects the developers to seek full cost recovery via the postage stamp RNS rate.

Separately, CMP and Maine Public Service (MPS) are developing the Maine Power Connection (MPC) project designed to provide the first connection between the MPS system in northern Maine to the New England bulk transmission system. The interconnection is primarily driven by the desire to deliver substantial wind generation proposed for Aroostook County to the rest of Maine and to the New England market. In particular, the project is designed to deliver the 800 MW Aroostook Wind Energy (AWE) project, a phased project with wind farms proposed for Fort Kent (175 MW), St. Agatha (200 MW), Hamlin (125 MW), and Bridgewater (300 MW) in Aroostook County, Maine.

The MPC consists of a 200-mile 345 kV line that will create a new north-south backbone for the MPS system, from Fort Kent in northernmost Maine through Presque Isle and extending to the southern end of the MPS service area in Houlton. From Houlton the MPC line would extend to the New England transmission system via Chester and to a new 345 kV switchyard adjacent to CMP's Detroit substation. The MPC is estimated at approximately $625 million, of which $439 million is associated with

transmission line work and $186 million with substations. In July 2008, CMP and MPS filed at the Maine PUC a siting application for the MPC.

Importantly, the MPC is not considered to be a reliability-driven upgrade. Rather, it is being studied by ISO-NE as an economic upgrade and as a request for interconnection.

Other Major Projects in ISO-NE RSP08

The latest ISO-NE RSP includes over 235 projects. In additions to the projects described above, other major projects identified in RSP07 include:

- The Merrimack Valley-North Shore Reliability Project – This $176.5 million National Grid project consists of multiple upgrades over a ten year horizon, including the reconductoring of various 115 kV lines, a new 345 kV Wakefield Junction substation, circuit breaker additions at the Sandy Pond 345 kV substation, and a capacitor bank addition at Revere Substation. Estimated in-service dates range from late 2008 and 2009 for most upgrades to summer 2011 for the more extensive re-conductorings.
- The Vermont Southern Loop project – This $274 million Vermont Electric Power Company (VELCO) project consists of a new 345 kV line between the Vermont Yankee, West Dummerston, and Coolidge substations in southern Vermont. Estimated in-service date is June 2011.
- Lower SEMA Upgrades – To remedy the ongoing uplift costs resulting from the running of the Canal generating units out of merit to meet second contingency requirements in the Southeastern Massachusetts (SEMA) load zone, ISO-NE and NSTAR have developed a package of both short-term and long-term transmission solutions. The short-term upgrades consist of a $49 million package of stability and voltage related upgrades (including new 150 MVAR capacitors and a 100 MVAR STATCOM), reconductoring, new autotransformers, and other improvements planned to enter service in stages through September 2009.

Table C-1: Major Transmission Projects in New England
Proposed, Authorized, or Under Construction in 2006-2008

	Estimated Cost (millions of $)
Northeast Reliability Interconnection (in service Dec. 2007)	144
Merrimack Valley / North Shore Reliability Project	177
Northwest Vermont Reliability Project (portions in service Jan. 2007)	288
Vermont Southern Loop	274
NSTAR 345 kV Stoughton-Boston Cables (2 cables in service, 3rd in Jun '09)	317
Southwest CT Project - Phase I (Bethel-Norwalk) (in service Oct. 2006)	357
Southwest CT Project - Phase II (Middletown-Norwalk)	1,427
Southwest CT Project - Norwalk-Glenbrook 115 kV cables	234
New England East-West Solution (NEEWS) (NGrid & NU)	1,601
Maine Power Reliability Program (CMP & NU)	1,424
TOTAL	**6,243**

APPENDIX B

PJM TRANSMISSION RATE DESIGN AND COST ALLOCATION CASE HISTORY AT FERC

In 1997, FERC approved the restructuring of PJM into an ISO, which included implementation of a PJM-wide open access transmission tariff (PJM OATT) with a license plate transmission rate framework. FERC's approval was subject to the commitment by PJM and its transmission owners to develop a uniform, system-wide rate methodology. In January 2005, the PJM transmission owners complied with this requirement by proposing to continue the existing zonal license plate rate design.

On May 31, 2005, FERC issued an order on the January 2005 filing finding that PJM's current zonal rate design may not be just and reasonable, and setting the matter for hearings before a FERC Administrative Law Judge (ALJ). Hearings were held in April 2006 and featured discussion of four proposed rate design frameworks. All of the proposed rate designs included some form of socialization, and three out of the four relied on voltage level distinctions for cost allocation (the FERC Staff proposal was the exception, proposing socialization of all existing facilities regardless of voltage level).

ALJ Decision

In his initial decision of July 13, 2006, the FERC ALJ found that PJM's license plate rate design for existing transmission facilities should be replaced with the postage stamp rate design recommended by FERC Staff. The ALJ concluded that PJM's continued use of license plate rates gives a "free ride" to customers who take delivery in an area of low or under investment in the transmission network while overcharging customers located in areas of high or adequate investment. The ALJ noted that PJM's high voltage transmission system is an integrated network that is equally beneficial to all users, and thus all users should pay the same per-unit rate.

As for new transmission facilities, the FERC ALJ conducting a related proceeding upheld PJM's 'beneficiaries pay' approach and rejected proposals to revise it. However, the ALJ agreed with suggestions to convene a stakeholder process to improve the definition of regional benefits for purposes of the PJM cost allocation process for new facilities. Importantly, PJM acknowledged on the record that regional cost allocation of new facilities 500 kV and above would be consistent with the PJM market design.

FERC Reverses ALJ Decision

On April 19, 2007, FERC issued Opinion No. 494, which reversed the ALJ ruling and reaffirmed PJM's current license plate rate design for allocating the cost of existing transmission facilities and of new facilities below 500 kV. The Commission based its reversal of the ALJ ruling decision largely on concerns that the socialized approach proposed by FERC Staff and endorsed by the ALJ would result in large cost shifts and unacceptable rate impacts for some PJM transmission customers.

As for new facilities, FERC determined that the costs of all new PJM-planned facilities that operate at or above 500 kV should be shared on a region-wide basis. Notably, FERC extended this postage stamp rate treatment to both reliability and economic projects.

FERC's decision represented a marked departure for transmission cost allocation in PJM, which has long been premised on a license plate rate 'beneficiary pays' approach. The decision represented a victory for transmission owners developing the PJM east-to-west "mega-projects" (*e.g.*, AEP and Allegheny), which have stated that they will not develop these billion-dollar projects absent cost recovery via a regional, PJM-wide cost allocation mechanism.

APPENDIX A

NEW BACKBONE PROJECTS UNDERWAY IN PJM

In 2006 and 2007, PJM authorized four major interstate projects representing well over $5 billion in investment. These four major projects are:

- Trans-Allegheny Interstate Line (TrAIL)
- Potomac-Appalachian Transmission Highline (PATH)
- Susquehanna-Roseland
- Mid-Atlantic Power Pathway (MAPP)

Below we provide a summary of these projects and their status as of September 2008.

TrAIL – Permitting Well Underway

Authorized by PJM in June 2006, the TrAIL project is the furthest along of the backbone projects approved by PJM in 2006-2007. To be built by Allegheny Energy and Dominion, the $1.1 billion TrAIL project is a new 500 kV line from southwestern Pennsylvania through West Virginia into northern Virginia.

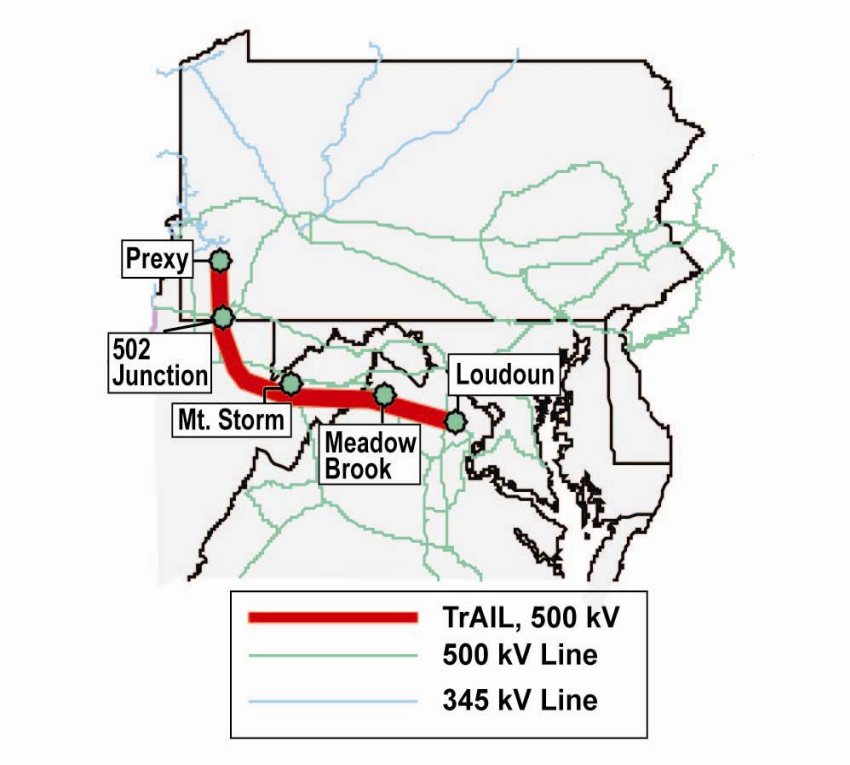

Figure A-1: Trans-Allegheny Interstate Line (TrAIL)

Specifically, the TrAIL project would run from a new Prexy substation in southwestern Pennsylvania to the 1,600 MW Mt. Storm coal plant in West Virginia, continuing east to the Meadow Brook substation in Middletown, Virginia and ending at Dominion's Loudoun Substation in the suburbs of northern Virginia. The Allegheny Energy portion of the project (Prexy-Meadowbrook, about 210 miles) is estimated to cost $820 million, while the Dominion portion in Virginia (65 miles) is estimated at $243 million. The project has an estimated in service date of June 2011, which is the date by which the project is needed to alleviate potential overloads and other reliability issues identified by PJM in the RTEP.

The siting process in the three states encompassed by the project has been underway for the last year. Allegheny filed siting applications with the West Virginia Public Service Commission (WV PSC) in March 2007, and with the Pennsylvania Public Utilities Commission (PA PUC) and Virginia State Corporation Commission (VA SCC) in April 2007 (concurrent with Dominion's application). Several weeks of contentious evidentiary hearings have concluded in all three states.

On August 1, 2008, the WV PSC approved the settlement and granted a siting certificate to the project. The Sierra Club has already indicated that it will appeal the decision to the West Virginia Supreme Court. In the meantime, Allegheny has begun the process of acquiring necessary rights-of-way in West Virginia.

On July 28, 2008, the VA SCC hearing examiner issued a report finding that the project is needed for reliability and should be approved. The hearing examiner recommended that the VA SCC condition its approval to the project obtaining approvals in West Virginia and Pennsylvania. A final decision from the VA SCC is expected by later this year.

As for Pennsylvania, on August 22, 2008, the PA PUC administrative law judges reviewing the TrAIL project issued a recommendation that the PA PUC reject the project. The ALJs found that "little or no need for reinforcement in the Prexy service area presently exists," and that granting siting approval to the project "rewards a lack of foresight and proper maintenance, and has policy implications for the location of future generation that should be carefully considered before any further action is taken." A final decision from the PA PUC is expected by year-end 2008.

Finally, the TrAIL project proponents have received important rate decisions from FERC. On July 21, 2008, FERC approved a settlement agreement that establishes a cost-of-service formula rate for TrAIL, and grants the project several rate incentives, including a return on equity (ROE) rate of 12.7%; full recovery of construction work in progress (CWIP) in rate base; and use of a hypothetical 50/50 capital structure and accelerated depreciation expense rates.

The rate and siting approvals to date have allowed Allegheny to already secure critical financing for the project. On August 15, 2008, Allegheny announced that it had closed on a $550 million senior secured credit facility with a seven-year maturity and an

initial borrowing rate equal to the London Interbank Offered Rate plus 1.875 percent. This credit amount represents roughly half of the estimated cost of the project.

Potomac-Appalachian Transmission Highline (PATH) Update

Responding to PJM's May 2005 conceptual proposal of a west-to-east "Mountaineer" transmission project, in January 2006 AEP proposed a 550-mile, $3+ billion 765 kV interstate transmission project, dubbed the I-765 project. Extending from AEP's Amos substation in western West Virginia into the Doubs substation in Maryland, and continuing through southeastern Pennsylvania to PSEG's Deans substation in northern New Jersey, the I-765 project would transfer 5,000 MW of energy and capacity from PJM West to PJM East. AEP partnered with Allegheny Energy and submitted the project to PJM for review and potential inclusion in the PJM RTEP as a backbone transmission project.

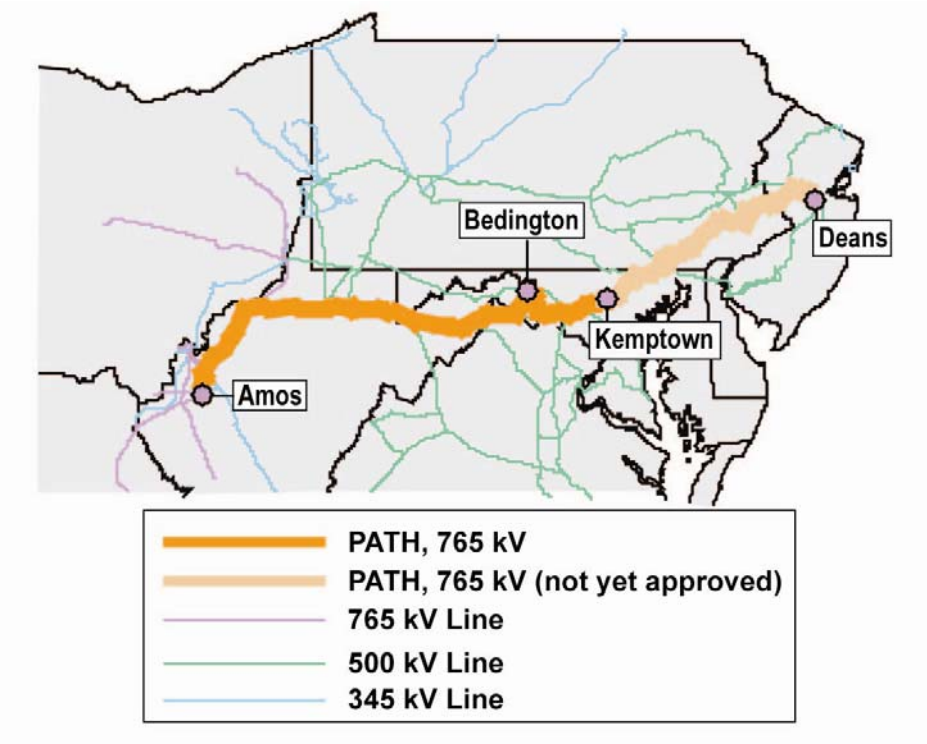

Figure A-2: Potomac Appalachian Transmission Highline (PATH)

In June 2007, PJM's Board of Managers authorized the $1.8 billion PATH project, consisting of approximately 250 miles of single-circuit 765 kV and 40 miles of twin-circuit 500 kV line, extending from the AEP's Amos substation in West Virginia to a new substation (Kemptown) to be built by Allegheny near Frederick, Maryland (and located a bit further east than the Doubs substation referenced above). Effectively, the PATH project represents the first half of the AEP I-765 project. The remaining portion of the I-765 project from Kemptown in Maryland to the Deans substation in New Jersey remains under study by PJM for potential inclusion in the RTEP, and is not part of the AEP/Allegheny joint venture.

In authorizing the PATH project, PJM indicated that the project is needed to relieve overloads that will occur as early as summer 2012 on 13 existing transmission lines in Maryland, Pennsylvania, Virginia and West Virginia. AEP and Allegheny are presently conducting numerous open houses and public meetings in the affected states, and are close to selecting a final route for the project. The companies expect to file siting applications in West Virginia, Maryland, and Virginia in late 2008, and are targeting an estimated completion date of June 2012.

Susquehanna-Roseland Update

Authorized by PJM in June 2007, the Susquehanna-Roseland 500 kV line would extend 130 miles from PPL's Susquehanna substation (adjacent to the Susquehanna nuclear power plant) in northeastern Pennsylvania to PSEG's Roseland substation near Newark, New Jersey. Estimated at a total of $1.1 billion, the $500 million Pennsylvania portion of project would be built by PPL and the $600 to $650 million New Jersey portion by PSEG. In addition, PSEG indicated that it will build two new substations associated with the line, one in Jefferson Township, Morris County, and another at its existing property in the Roseland/East Hanover area. PJM has indicated that the line is needed as early as the summer of 2013 in order to address overloads anticipated on 23 existing transmission lines in Pennsylvania and New Jersey. The project developers estimate an in service date of June 2012.

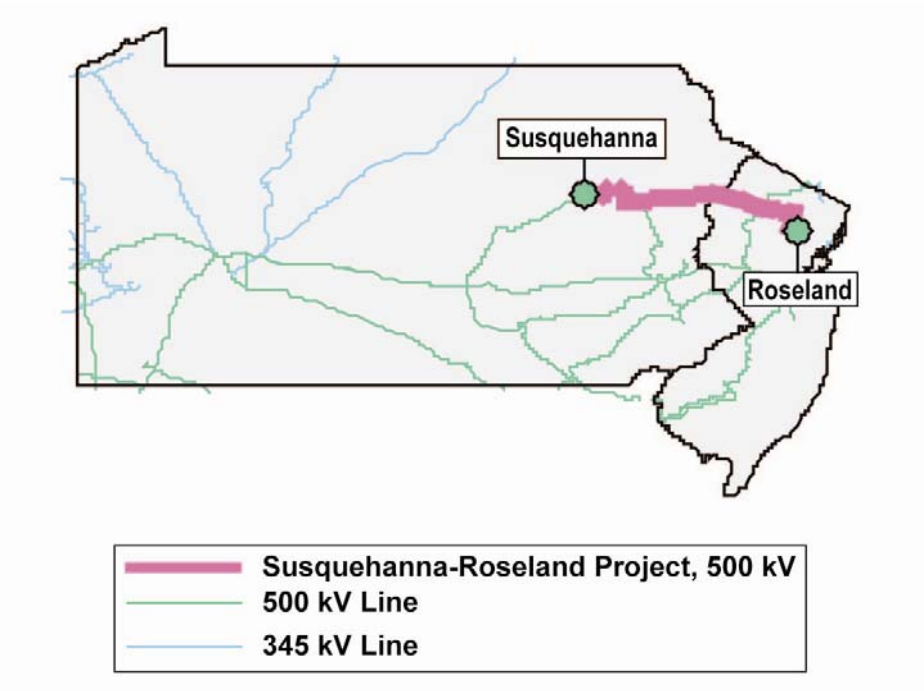

Figure A-3: Susquehanna-Roseland Project

In August 2008, PPL and PSEG announced that they had completed the route selection process. The selected route follows an existing 230 kV transmission corridor

for virtually the entire route (save for a very short stretch in Pennsylvania). PPL and PSEG are presently preparing siting applications to be filed with Pennsylvania and New Jersey regulators in the fourth quarter of 2008.

Mid-Atlantic Power Pathway (MAPP) Update – HVDC Across the Bay

Pepco Holdings Inc.'s (Pepco) MAPP project was approved by PJM in October 2007. The MAPP project is a new 230-mile 500 kV transmission line running from the Possum Point Station in northern Virginia into Maryland and the Calvert Cliffs nuclear plant, and then crossing the Chesapeake Bay to the Delmarva Peninsula and heading north through Delaware (via the Indian River coal plant) to the Salem Station in southern New Jersey.

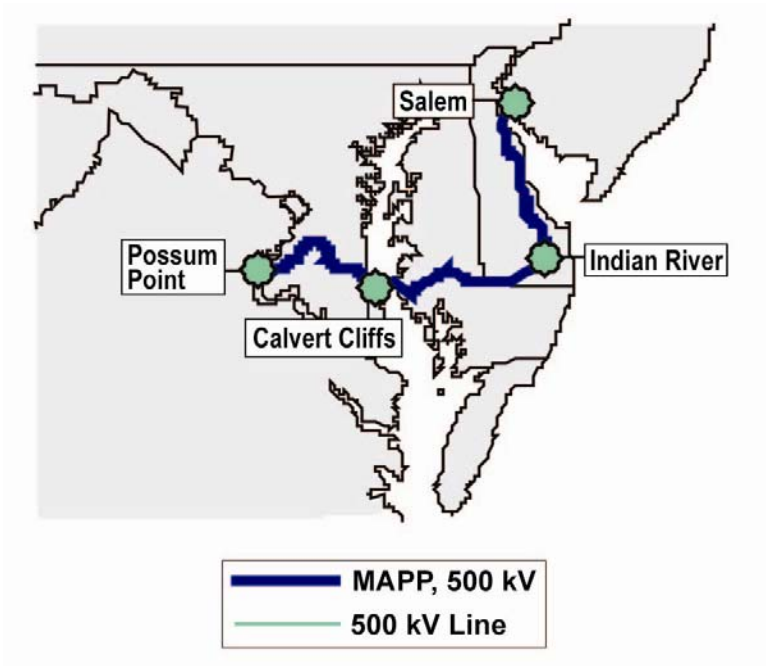

Figure A-4: Mid-Atlantic Power Pathway (MAPP) Project

In authorizing the MAPP project, PJM noted that in addition to relieving expected overloads on the existing transmission system, the new line would also address the chronic energy congestion in the Delmarva Peninsula. Presently, the peninsula has limited local generation and a relatively weak radial transmission system, which comes only from the north at a maximum voltage of 230 kV. The MAPP project will significantly upgrade the peninsula's transmission network by adding a 500 kV north-south backbone as well as a transmission path into the southern end of the peninsula. PJM also noted that the MAPP project addresses issues raised by the planned retirements by 2012 of two power plants located inside Washington, D.C. – Pepco's Benning Road and Buzzard Point, totaling 800 MW of capacity.

The latest development on the project relates to the potential use of a high voltage direct current (HVDC) system for crossing the Chesapeake Bay. Concerns over voltage issues with the use of 500 kV AC submarine cables are driving Pepco to install a voltage-source converter HVDC cable system for this portion of the line. HVDC cables also

provide significant siting benefits, as using HVDC requires fewer cables and thus a smaller footprint, as well as allowing the use of solid (plastic-insulated) cable instead of oil filled or impregnated AC cables. Pepco also proposed to construct three HVDC circuits for the Chesapeake Bay crossing, each of which could be operated individually and thus provide significant flexibility together with the controllability of HVDC systems.

Pepco projected an additional cost of $400 million for the combined AC and DC solution, raising the total expected cost to $1.45 billion. Pepco will request PJM to endorse the change in the project scope.

A New PJM Interstate Transmission Network

PJM's endorsement of these four projects together with earlier FERC approvals of regional cost recovery for new 500 kV and above transmission projects and of rate incentives for the AEP I-765 and Allegheny 500 kV projects, provides critical and robust support. Of course, significant siting hurdles remain – and all under multiple state jurisdictions. The "hammer" of Federal eminent domain authority looms over these projects, as all lie squarely within the recently designated Mid-Atlantic National Interest Electric Transmission Corridor (NIETC).

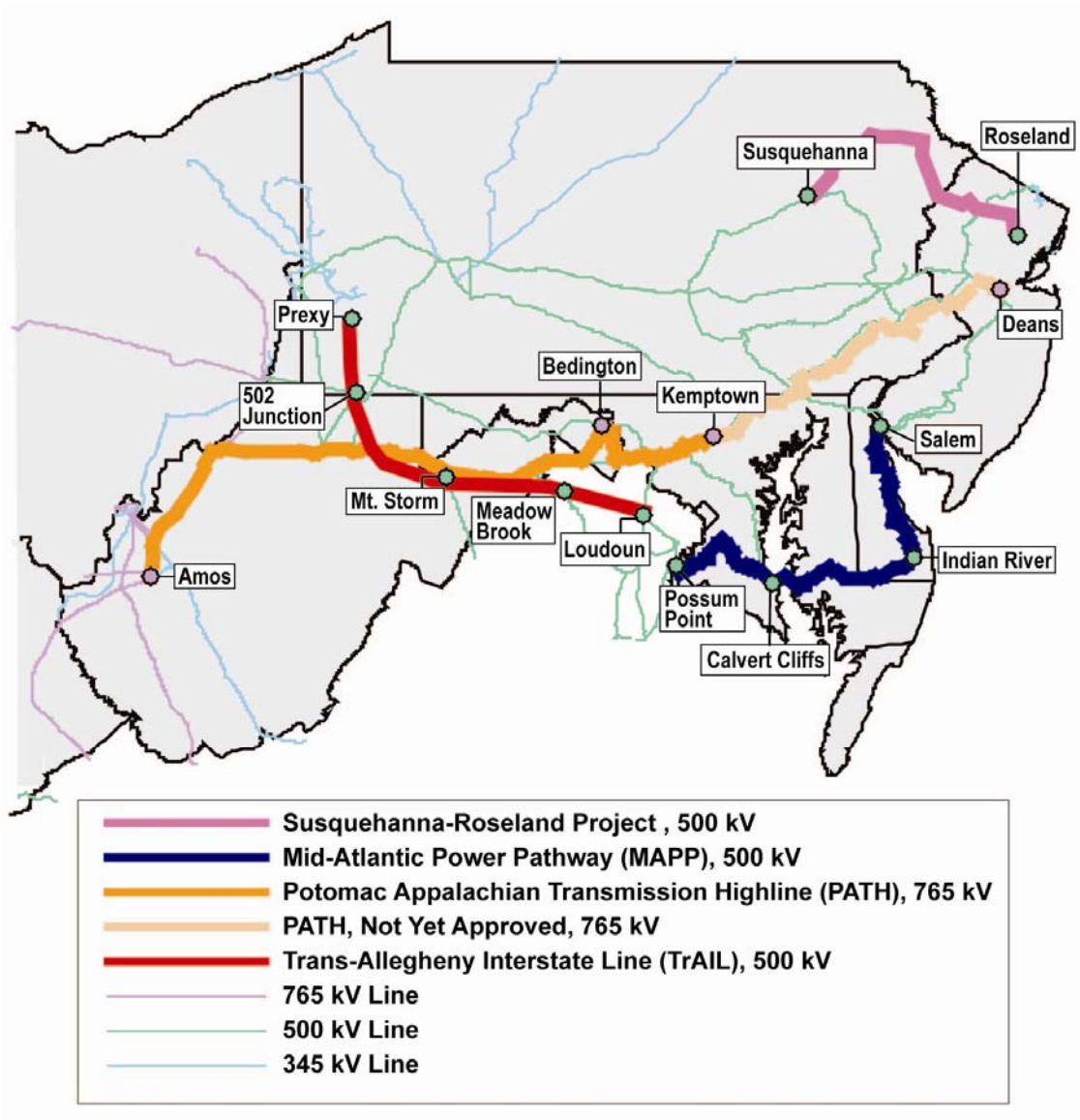

Figure A-5: PJM-Authorized Backbone Transmission Projects 2006-2007

APPENDIX D

OTHER ISO/RTO APPROACHES TO TRANSMISSION FOR RENEWABLES

California and Texas have pioneered the linking of environmental and public policy mandates to transmission planning. The ideas and mechanisms developed in these two states have shaped the debate regarding transmission for renewable resources, and ESAI expects these mechanisms to quickly spread to other regions. Similar mechanisms have been implemented in Colorado and are under discussion in several Midwestern states under the auspices of the Midwest ISO. In the Northeast, ISO-NE and PJM are only now beginning to tackle this issue.

Below we summarize the California and Texas initiatives to build transmission for renewable resources. We also summarize the approaches underway at two multi-state RTOs, ISO-NE and Midwest ISO.

California – Renewable Trunklines

FERC's approval of California ISO's (CAISO) proposal for a so-called "third" category of transmission facilities – for transmission trunk lines designed to access "locationally constrained" renewable resources – is a significant departure from traditional transmission ratemaking policies. Under the approved mechanism, CAISO will initially include the costs of renewable trunk line costs in the regional CAISO-wide Transmission Access Charge (TAC), with generation developers providing a reimbursement over time as they interconnect. The reimbursement would be based on their share of the going-forward costs of the line at the time of their interconnection. The intent is for renewable generation owners who use the line to ultimately bear the cost of the line once the region's renewable resource is fully developed. In the meantime, however, the line would receive socialized treatment under the CAISO TAC – thus allowing cost recovery for facilities before they are 'used and useful' in providing transmission service.

To qualify as a renewable trunkline, the CAISO rules require that that there must be generator interest in the facility equivalent to 60% of its rated capacity. The 60% must include firm commitments by generators to pay a *pro rata* share of the transmission facilities for at least 25% of the line's capacity.

In effect, CAISO and FERC are allowing ratepayers to fund transmission lines that do not meet reliability or economic tests (or even traditional 'used and useful' prudence standards) in order achieve a different policy goal: encouraging the development of renewable resources. While the upfront funding from ratepayers would be reimbursed as generators connect to the trunk line, this funding would occur regardless of whether enough generators ultimately connect – a utility ratemaking version of "if you build it they will come." In doing so, California has chosen (with FERC's consent) to incorporate a broader environmental goal into its transmission planning objectives. ESAI expects the renewable trunk line concept to spread to several other regions.

The first project to avail itself of this approach is Southern California Edison's Tehachapi Renewable Transmission Project, which began construction in March 2008. The $1.8 billion project consists of a series of 17 new facilities or upgrades that will come on line over a period of five years, beginning in late 2008. When completed in 2013, the project will permit the delivery of 4,500 MW of renewable resources in the Tehachapi area. The project also eases transmission constraints in the Antelope Valley region and allows the future expansion of Path 26, a major north-south transmission corridor.

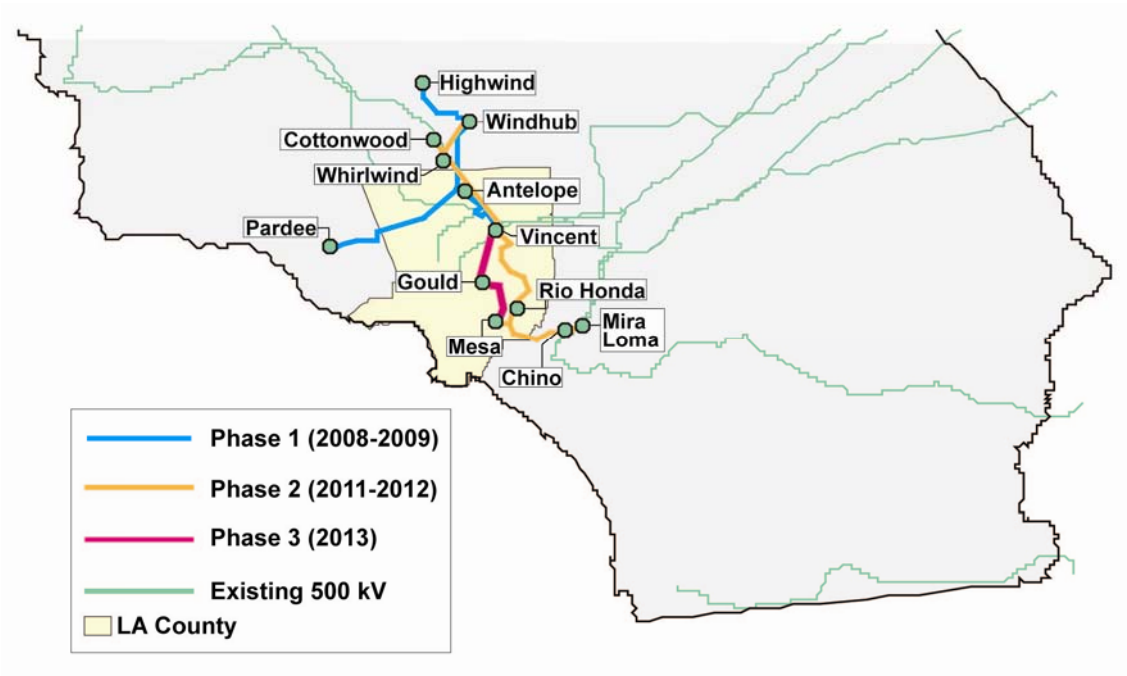

Figure D-1: SCE Tehachapi Project, 500 kV

Discussions are underway for CAISO to go further in incorporating other public policy goals into its planning and system operation roles. CAISO intends to play an integral role in developing and implementing greenhouse gas emissions controls in the electricity sector, since enforcement of California's climate change laws will significantly affect system reliability and market operations. CAISO's precise role in implementing climate change policy is under discussion, but one alternative would be for CAISO to explicitly address and include greenhouse gas emissions in its planning process. Such a step would represent an incremental and logical evolution of the renewable trunk line mechanism. CAISO's economic transmission planning mechanism explicitly includes access to renewable resources as a criterion for economic transmission projects eligible for socialized cost recovery via the CAISO TAC (and apart from the "location-constrained resource interconnection facilities" or renewable trunk lines category).

Recently, in late 2007 California launched the Renewable Energy Transmission Initiative (RETI), a statewide collaborative process to identify transmission projects needed to accommodate California's present and future energy policy. California's present RPS requires retail sellers of electricity to obtain 20% of their supply from

renewable energy sources by 2010, and the recently adopted Energy Action Plan seeks to increase renewable energy to 33% of state supply by 2020. Furthermore, California has adopted an extensive greenhouse gas emissions reduction plan that is likely to increase the procurement of renewable energy from the scale anticipated by the Energy Action Plan.

The objective of RETI is to identify the renewable energy resource zones in California and in neighboring states that can be developed in the most cost effective and environmentally benign manner, and prepare detailed transmission plans for the resource zones identified for development. After its conclusion, the RETI expects that the permitting process for each identified resource zone-driven transmission project will be initiated, and that these projects would qualify for "renewable trunkline" cost recovery treatment. The RETI is open to stakeholders and will be supervised by a coordinating committee comprised of the California Public Utilities Commission, the California Energy Commission, CAISO, and several California public power entities. The first phase of the RETI work plan, identification of cost-effective renewable energy resource zones, is expected to be complete by September 2008.

Texas – Designation of CREZs to Enhance a Renewable Powerhouse

As in the California renewable trunk line mechanism, Texas has established an explicit incorporation of criteria other than reliability and economics into the transmission planning process. Long the center of the U.S. oil and natural gas industry, Texas surprises many by leading the nation in wind power capacity with over 4,350 MW installed and in service (California is second with 2,400 MW), and an additional 1,300 MW of wind resources under construction (nameplate ratings, as reported by AWEA). In 2007 alone, Texas added over 1,600 MW of new wind generation. Furthermore, Texas's wind generation potential is huge, with another 54,000 MW included in the ERCOT interconnection queue as of July 2008.

Impetus for this large investment in wind capacity comes from Texas's existing transmission planning and cost allocation policies, as well as siting policies. Transmission costs in ERCOT are recovered via a socialized uniform postage stamp rate, with the usual exception of generator interconnection costs, which are to be paid by generators.

However, Texas plans for transmission for additional renewable generation will go much further. In enacting increases to the state's RPS requirements, the Texas legislature required the Public Utility Commission of Texas (PUCT) to designate as Competitive Renewable Energy Zones (CREZ) areas in Texas with high-quality clean energy resources that require transmission to be built to allow access to load centers. Moreover, the law authorized the PUCT to order utilities to construct or expand transmission between the CREZ and load centers to help meet the Texas RPS requirements. Importantly, under the law and PUCT regulations, transmission proposed for CREZ automatically meets 'used and useful' and prudence criteria.

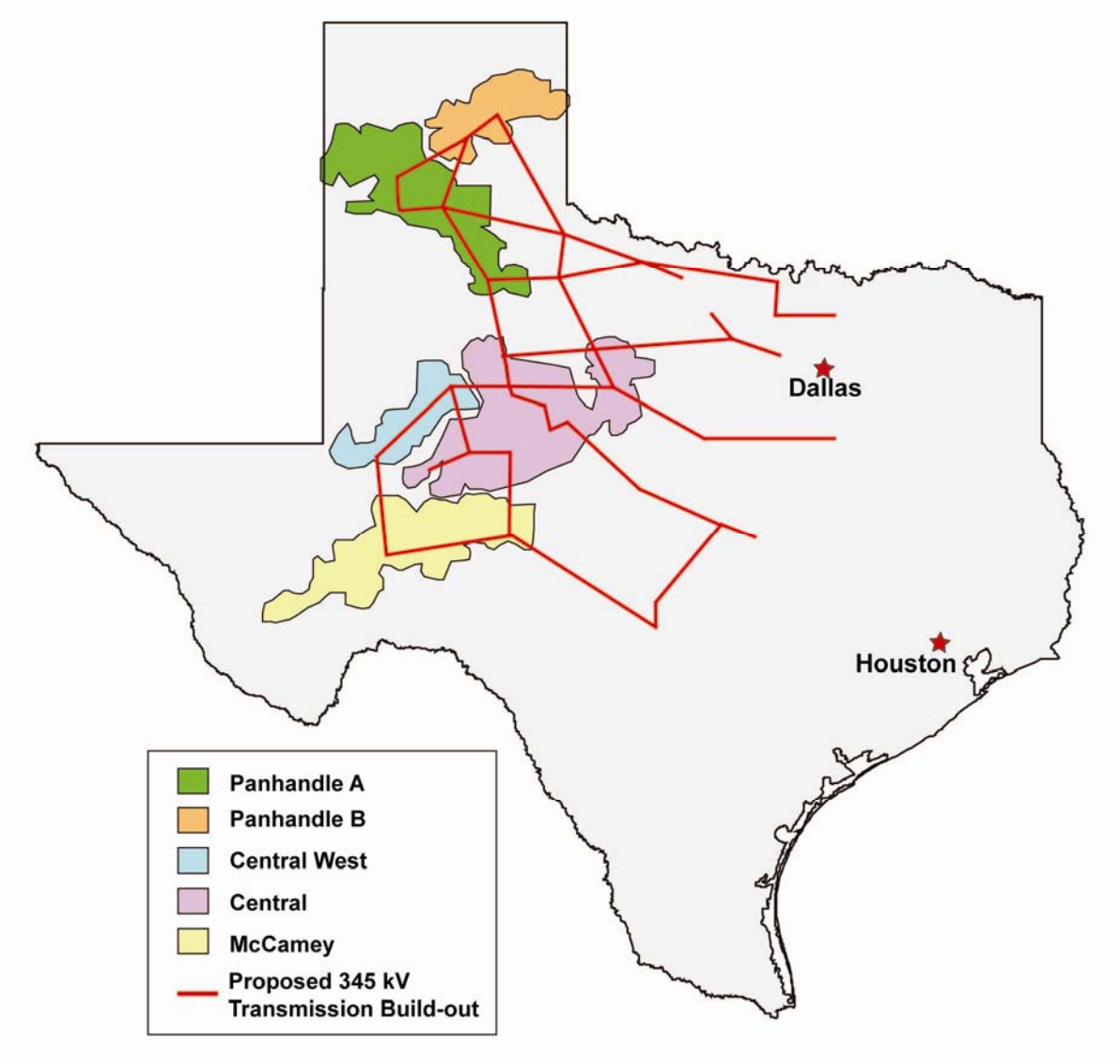

Figure D-2: Competitive Renewable Energy Zones Designated by the PUCT

In October 2007, the PUCT issued an interim order that: (1) designated five CREZ areas, as shown in Figure D-2; (2) identified generation projects that showed financial commitment and thus enabled designation of CREZs; and (3) developed transfer capability scenarios to assist ERCOT in conducting a study to identify the transmission improvements needed to move energy from a designated CREZ area to load.

ERCOT delivered its study of potential CREZ-related transmission improvements in April 2008. The ERCOT study identified five transmission buildout alternatives, ranging from $2.95 billion to $6.38 billion in cost, and providing deliverability ranging from 12,053 MW to 24,859 MW. In July 2008, the PUCT selected an identified alternative that would provide 18,456 MW of transfer capability from West Texas and the Panhandle to the metropolitan areas of the state at an estimated cost of $4.93 billion, or approximately $4.00 per month per residential customer. All CREZ transmission costs will be socialized across all load serving entities in ERCOT.

The PUCT has now begun a rulemaking to establish criteria for selecting the entities responsible for constructing the transmission improvements, which will be required to file siting applications with the PUCT within one year. The process is designed to promote competition in the construction and ownership of these projects, and any entity can qualify to construct and own the upgrades provided that it demonstrates that it has the ability to construct, operate, and maintain the facilities. Qualified transmission developers will then file proposals to construct and operate the CREZ transmission facilities. The PUCT expects to qualify transmission developers by the end of 2008 and select proposals filed by qualified transmission developers by July 2009. Transmission developers designated for each of the identified CREZ-related upgrades will then be required to file siting applications with the PUCT.

This competitive solicitation process has stirred significant interest in the transmission industry. Several entities are jockeying for a piece of the CREZ transmission pie, including well-funded entities such as FPL Energy's Lone Star Transmission LLC, Babcock & Brown's Tejas Transmission LLC, and the AEP/MidAmerican joint venture Electric Transmission Texas LLC.

After the transmission developer files its siting applications, generation developers in the designated CREZ must post a letter of credit or other collateral equal to 10% of their share of the CREZ transmission upgrade costs, an amount that is refundable to the generation developer once its project is built and connected to the line.

Financial commitments made by renewable energy developers were a determining factor in the PUCT's CREZ designations. Areas that had been preliminarily identified as potential CREZs but lacked sufficient developer interest as evidenced by financial commitments were not designated as CREZs in the interim order. Factors reviewed by the PUCT included whether generation developers had: (1) existing renewable resources; (2) pending or signed interconnection agreements; (3) leasing agreements (*e.g.* site control); (4) letters of credit; (5) completed interconnection studies; (6) a non-utility entity's commitment to build and own transmission facilities; and (7) a deposit or payment to secure or fund the construction of such transmission facilities by an electric utility or transmission facility. In its interim order, the PUCT provided a listing by designated CREZ area of the generators found by the PUCT to demonstrate sufficient financial commitment, and specifies the commitments made by each generator.

New England – Embracing Economic Planning to Address Green Policy Mandates

All six New England states have enacted renewable portfolio standards and are RGGI participants. Furthermore, New England has a long history of collaboration in electric infrastructure planning, with the region cooperating closely to build the Yankee nuclear reactors as well as HVDC transmission ties (and an associated joint power purchase agreement) with Québec. In continuing to refine its Regional System Plan (RSP) process, ISO-NE has begun a discussion of incorporating criteria other than reliability and economics into the planning process.

ISO-NE's 2007 RSP (RSP07) highlighted the need for resources that would both alleviate the region's over-dependence on natural gas and oil facilities, and comply with increasingly stringent environmental and renewable energy policy mandates. But the New England interconnection queue remains dominated by gas-fired projects. Although wind (almost 2,700 MW as of July 2008) and other renewable resources constitute the second largest category of fuel in the queue, New England has the least amount of wind and other renewable resources of the three Northeast ISOs.

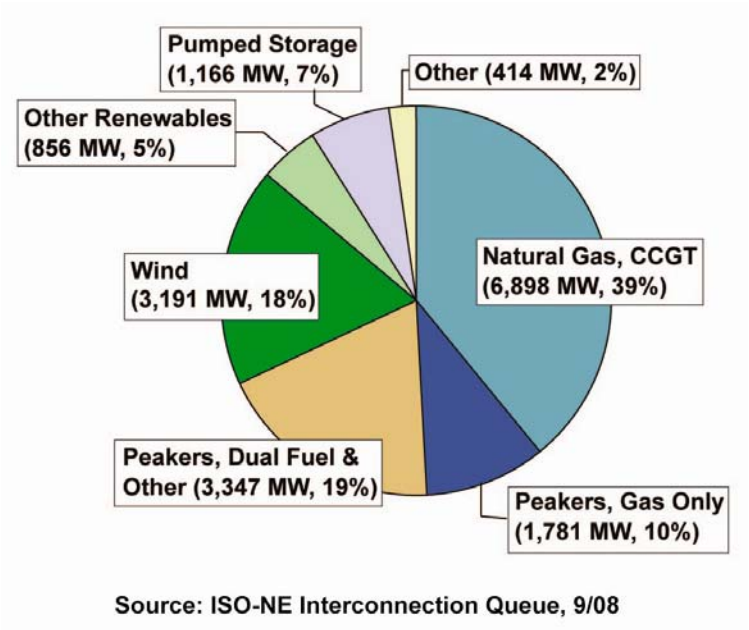

Figure D-3: ISO-NE Interconnection Queue Fuel Mix of Projects, September 2008; MW

In December 2007, ISO-NE invited developers to propose long-haul transmission solutions to increase the deliverability of renewable and low-carbon resources into New England. The proposals are to be evaluated under the economic planning provisions of the ISO-NE tariff. Almost a dozen proposals were received and are presently under review by ISO-NE and stakeholders. Most proposals focused on high voltage direct current (HVDC) transmission solutions.

Separately, Central Maine Power (CMP) and Maine Public Service (MPS) have proposed to construct the Maine Power Connection, a 200-mile 345 kV line designed to provide the first connection between the MPS system in northern Maine and the New England bulk transmission system. The interconnection is driven by the desire to deliver up to 800 MW of wind generation proposed for Aroostook County to the rest of Maine and the New England market via a new north-south backbone for the MPS system. The current cost estimate for the MPC Project is approximately $625 million, of which $439 million is associated with transmission line work and $186 million with substations.

Individual New England states are also examining how to provide additional north-south transfer capability to encourage development of renewable resources. In December 2007, the New Hampshire Public Utilities Commission (NHPUC) released a report to the state legislature outlining potential options for upgrading New Hampshire's transmission

system to facilitate development of the state's renewable resources, primarily located in northern New Hampshire. Interestingly, one funding alternative mentioned in the NHPUC report is to use the proceeds from the auctions of RECs and/or RGGI carbon allowances to fund transmission specifically targeted for renewable energy development. Under RPS and RGGI rules, proceeds from REC and carbon allowances typically go towards energy efficiency and the development of renewable resources – but not necessarily transmission.

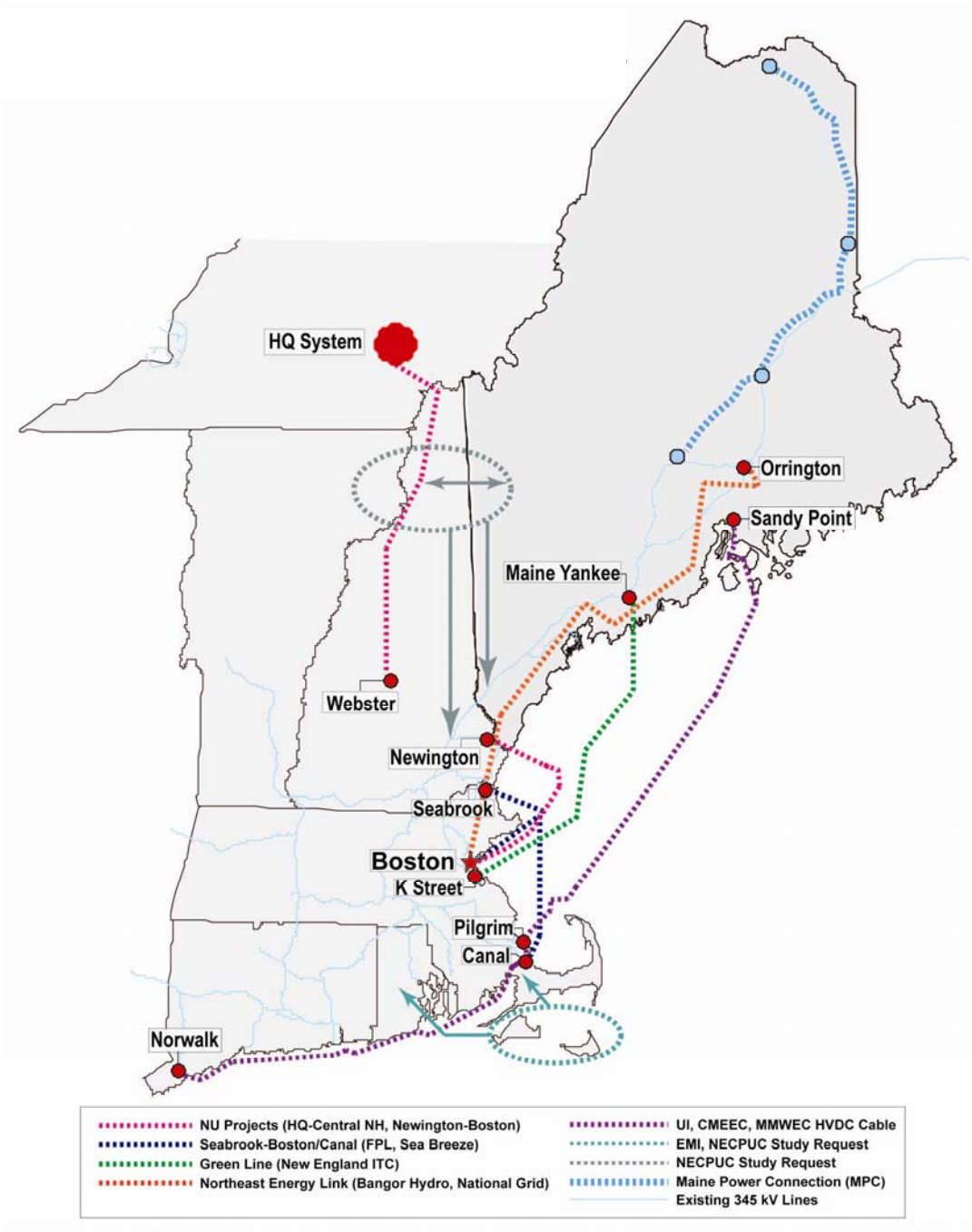

Figure D-4: Potential Economic Transmission Projects in New England

In addition to being driven by renewable resources, all of these projects seek to be included in the pool-supported, Regional Network Service (RNS) rate, thus setting the stage for an interesting debate on the need for and the economics of these projects. ISO-NE has begun a stakeholder process to review the necessary tools, tariff mechanisms, and overall expertise to tackle the decision of whether New England's ratepayers should fund any of these projects. Important details regarding the regulatory test to be applied, definitions and mechanisms for determining project benefits and costs, and whether the projects should proceed as economic or reliability-driven upgrades remain murky. Ultimately, it remains to be seen whether the attempt to shoehorn 'green' policy criteria into an economic-driven framework will allow development of transmission for renewable resources.

One final obstacle to these renewable-driven north-south projects is the State of Maine's ongoing evaluation of whether to remain in the New England RTO arrangements. Maine continues to be dissatisfied with the cost allocation regime and forward capacity market construct in New England, and is considering ordering its utilities to leave ISO-NE and implement other system operation and market arrangements, perhaps with the Canadian Maritime provinces. In December 2007, the Maine Public Utilities Commission submitted a final report to the Maine legislature on alternatives to the present New England RTO arrangements. Geographically, Maine is key to the future needs of New England as it serves both as a source of significant generation (including large amounts of wind resources), and as a transmission path for significant imports (renewable and other) from Canada.

Midwest ISO – How to Deliver an Enormous Wind Resource

Depending on your point of view, the Midwest ISO is either blessed or cursed with a huge wind resource – over **87,000 MW** of active wind projects are in the queue as of August 2008. This amount is enormous by any measure, but it is particularly staggering given the Midwest ISO's peak demand of approximately 110,000 MW and total existing generation capacity of around 127,000 MW.

The Midwest ISO's large wind resource is complemented by a generator interconnection policy that splits transmission upgrade costs for generator interconnections on a 50-50 basis between generators and load if the generation facility's output is committed to network customers or designated as a network resource. Transmission cost recovery for Midwest ISO transmission owners is accomplished via a license plate approach similar to PJM, including the allocation of new transmission upgrades to beneficiaries based on a distribution factor approach. However, the Midwest ISO recently implemented a regional postage stamp rate designed to recover 20% of the costs of higher voltage (greater than or equal to 345 kV) facilities, with the remaining 80% allocated on a 'beneficiary pays' basis.

The Midwest ISO has a robust reliability planning process in its Midwest Transmission Expansion Plan (MTEP), which has approved over $2.2 billion in reliability-driven transmission projects through 2013. However, it is clear that to interconnect such a huge wind resource requires another type of planning effort.

One such effort is the CapX 2020 initiative, a joint transmission planning effort among 11 transmission owners in Minnesota, North Dakota, South Dakota, Wisconsin, and Missouri. A key objective of CapX 2020 is to support the development of renewable resources in order to meet state RPS requirements (for example, Minnesota's RPS requires 25% of electricity to be supplied by renewable sources by 2025). CapX 2020 has identified several new transmission line projects to be built in phases and completed by 2020. The first group of projects (Group 1) consists of three 345 kV lines and a proposed 230 kV line, with a combined cost in excess of $1.5 billion (the 345 kV projects will be included in the 2008 MTEP). The CapX 2020 partners have development agreements in place to construct the projects once they are approved by the individual states. Costs would be recovered through a combination of the Midwest ISO regional postage stamp rate and the local transmission owner license plate rates.

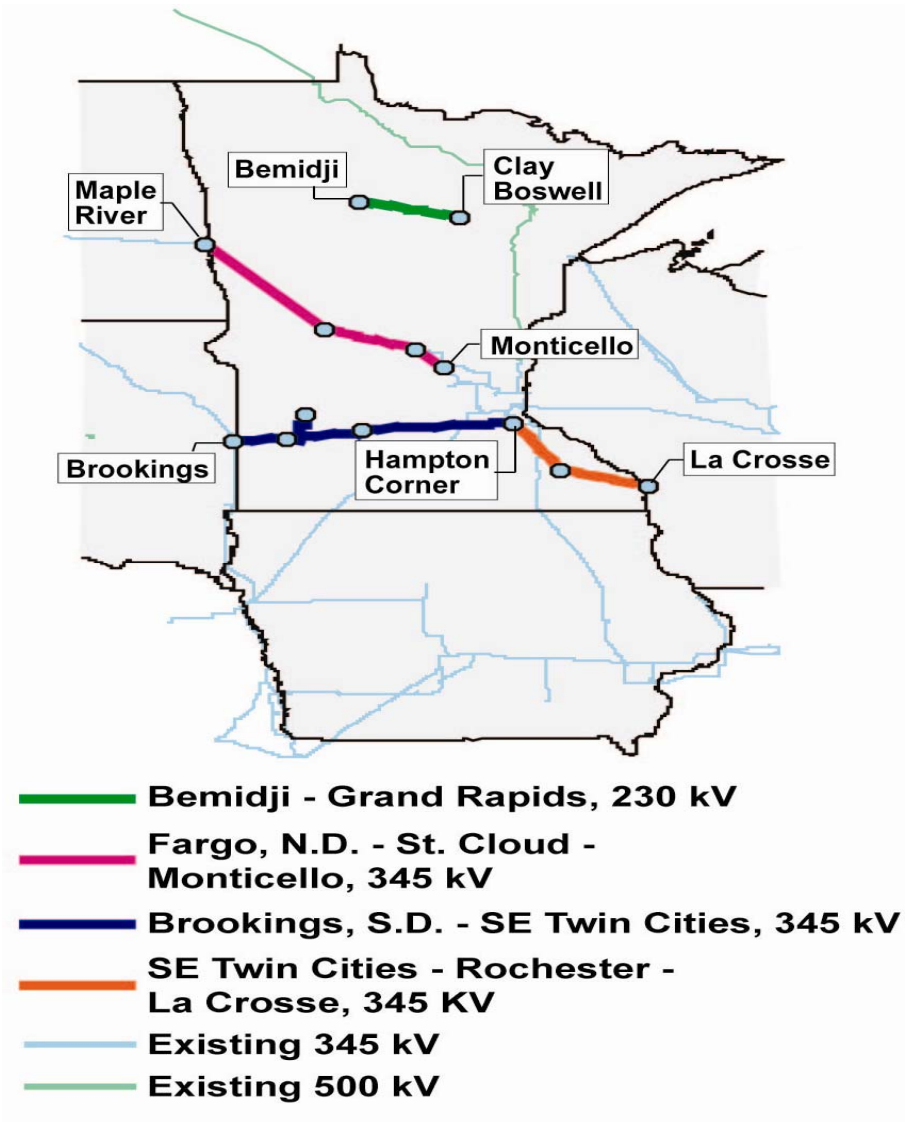

Figure D-5: CapX 2020 Projects

Another planning effort is the Midwest ISO's Regional Generation Outlet Study, which includes a study to identify the amount of transmission needed to meet individual state RPS requirements within the Midwest ISO footprint. To the extent other capacity/energy requirements or needs are identified consistent with the intent of this study, they may be included as well. Ultimately, the study will provide a year by year set (over the next 5 to 15 years) of a "renewable collector system" of transmission projects to be included in the MTEP process.

Finally, the Midwest ISO is leading the Joint Coordinated System Plan (JCSP) study, an inter-ISO planning effort that includes PJM, NYISO, ISO-NE, the Southwest Power Pool (SPP), and the Tennessee Valley Authority (TVA). In addition to developing analytical models to perform inter-control area coordinated system planning and reliability studies, a key objective of the JCSP is to contribute to the U.S. Department of Energy's Eastern Wind Integration & Transmission Study by studying the impacts on the Eastern Interconnection associated with meeting a regional RPS of 20% and 30%. These RPS levels are assumed to require delivery of 135,000 MW of wind for the 20% standard and an additional 200,000 MW of wind for the 30% standard, for a total of over 300 GW of wind resources. Importantly, the JCSP is a power system impact and integration exercise, and does not focus on mechanisms to fund such an extraordinary level of investment.