NEW YORK
STATE OF
OPPORTUNITY.

Public Service Commission

Three Empire State Plaza, Albany, NY 12223-1350
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January 16, 2015

SENT VIA ELECTRONIC FILING
Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Room 1-A209
Washington, D.C. 20426

Re: Docket No. ER15-572-000 - New York Transco, LLC, et al.

Dear Secretary Bose:

For filing, please find the Protest of the New York State Public Service Commission in the above-entitled proceeding. The parties have also been provided with a copy of this filing, as indicated in the attached Certificate of Service. Should you have any questions, please feel free to contact me at (518) 473-8178.

Very truly yours,

David G. Drexler
Assistant Counsel

Attachment
cc: Service List

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

| | | |
|---|---|---|
| New York Transco, LLC | ) | |
| | ) | |
| Central Hudson Gas & Electric Corp. | ) | |
| Consolidated Edison Company | ) | |
| of New York, Inc. | ) | Docket No. ER15-572-000 |
| Niagara Mohawk Power Corp. | ) | |
| d/b/a National Grid | ) | |
| New York State Electric & Gas Corp. | ) | |
| Orange & Rockland Utilities, Inc. | ) | |
| Rochester Gas and Electric Corp. | ) | |

**PROTEST OF THE NEW YORK STATE**
**PUBLIC SERVICE COMMISSION**

## INTRODUCTION

The New York State Public Service Commission (NYPSC) hereby submits its Protest to the request for rate recovery and associated ratemaking treatment that was filed by New York's Investor-Owned Utilities (IOUs)[1] on December 4, 2014 (Petition).[2] The Petition requests authorization to establish a formula rate for allocating and recovering the costs of constructing certain transmission facilities that would be developed by the IOU's

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[1] The IOUs include Central Hudson Gas & Electric Corp., Consolidated Edison Company of New York, Inc. (Con Edison), Niagara Mohawk Power Corp. d/b/a National Grid, New York State Electric & Gas Corp. (NYSEG), Orange & Rockland Utilities, Inc., and Rochester Gas and Electric Corp.

[2] The NYPSC submits its Protest pursuant to the Federal Energy Regulatory Commission's (FERC or Commission) Notice Granting Extension of Time, issued on December 22, 2014, and Rule 211 (18 C.F.R. §385.211) of the Commission's Rules of Practice and Procedure. The NYPSC's Notice of Intervention was filed on December 16, 2014.

newly-created affiliate, New York Transco, LLC (NY Transco).[3] The IOUs identify for NY Transco ownership an initial set of five transmission facilities that were proposed in NYPSC planning proceedings, which are described in the Background section below.

The Petition further seeks to establish a 10.6% base Return-on-Equity (ROE), to which ROE incentives totaling 150 basis points would be added. The Petition also seeks risk-reducing rate-making treatment. The total ROE would be capped at 11.63%, which represents the upward bound of the IOU's proposed zone of reasonableness.

As discussed below, the NYPSC objects to the IOU's Petition because it seeks an excessive ROE that will result in unjust and unreasonable rates, and thereby harming ratepayers. The IOUs overstate the risks, while understating the financial viability of NY Transco. The IOUs' affiliation with NY Transco will ensure it can avail itself of adequate expertise and experience in developing multiple transmission projects, and will assist in obtaining sufficient access to capital. The requested incentive ratemaking treatment related to Construction Work In Progress (CWIP) and abandoned plant will further reduce the risks associated with developing projects.

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[3] The NYPSC is concurrently filing a Protest to the IOUs related filing, in Docket No. EC15-45, requesting authorization to transfer transmission facilities to NY Transco.

While the NYPSC is supportive of ROE incentive adders that are truly reflective of risks or present innovative technologies that benefit consumers, such risks or technologies are not present in the case of the IOUs forming and operating NY Transco. It is also not appropriate to award ROE incentives in cases where the action being incentivized would occur even without an incentive, such as in the case of NY Transco transferring operational control to the New York Independent System Operator, Inc. (NYISO). In light of these circumstances, the ROE incentive adders and hypothetical capital structure requested by the IOUs are even more unnecessary and excessive. Accordingly, the Commission should conduct a hearing to address disputed questions of fact regarding the ROE, and to ensure the NY Transco's total ROE, inclusive of any incentive ratemaking and ROE incentive adders, is just and reasonable.

The NYPSC further objects to the Petition because it presents a materially different set of factors than those which the NYPSC relied upon in selecting three of the five proposed transmission projects for development. In particular, the IOUs now seek to impose an allocation of costs involuntarily upon other New York Transmission Owners (NYTOs), namely the Long Island Power Authority (LIPA) and New York Power Authority (NYPA). The voluntary allocation of costs to LIPA and NYPA covering a suite of 18 transmission projects across the State, as was initially presented to the NYPSC by the IOUs, were primary factors in the NYPSC's endorsement of NY Transco and the proposed cost allocations. In the absence of LIPA and NYPA's agreement and a reduced scope of projects, the Commission should conduct a hearing to ensure the just and reasonable allocation of costs.

In addition, the IOUs present higher cost estimates for two of the three transmission projects, referred to as the Transmission Owner Transmission Solutions (TOTS), than they previously provided to the NYPSC. The NYPSC relied upon these estimates in conducting a competitive process that resulted in a determination that these transmission projects had net benefits. The IOUs now seek to disavow themselves of these cost estimates, which were a key factor in the NYPSC's decision accepting the projects for development. The Commission should respect the integrity of the State's competitive selection process by limiting the IOUs' recovery of costs that exceed those estimates, or alternatively impose a risk-sharing mechanism between NY Transco's shareholders and ratepayers for the sharing of cost overruns above the estimates that the NYPSC relied upon. These measures are essential to avoid the significant increases in revenue requirement between what the NYPSC assumed in accepting the TOTS projects for development, and what the IOUs have requested in the Petition. As detailed in Appendix D, the

Petition would result in an increased revenue requirement for the TOTS of $300 million for the first 16 years, and over $456 million over 40 years.

Finally, the NYPSC objects to the requested rate treatments related to the two other proposed transmission projects (referred to as the "AC Upgrades"), which are still under consideration in another NYPSC planning proceeding. Because these projects are currently being evaluated and no decision has been made as to whether they should proceed with further development, it is premature to grant the IOUs request.

## BACKGROUND

### I. The Petition

The NY Transco's proposal would allocate costs on a NYTO-specific percentage basis, which would result in approximately 75% of the costs being allocated to downstate, and the remaining amount to upstate. The IOU's proposal also requests a base ROE utilizing a national proxy group of 30 companies to produce a zone of reasonableness of 6.25% to 11.63%, with a midpoint at 8.78%. The IOUs request a base ROE of 10.6% based on the point that is halfway between the midpoint of 8.78% and the upper end of the zone of reasonableness (i.e., 11.63%). The IOUs also request adders totaling 150 basis points in ROE incentives to further compensate investors and lenders.

These adders consist of: 1) a 50 basis point adder for forming a transmission-only entity that will focus exclusively on developing and operating needed transmission facilities to relieve chronic or severe grid congestion that has had demonstrated cost impacts to consumers; 2) a 50 basis point adder to compensate NY Transco for any significant development, construction, regulatory and financing risks; and, 3) a 50 basis point adder for NY Transco becoming a member of the NYISO and turning over operational control of its transmission facilities to the NYISO. The base ROE and ROE incentive adders would result in a total ROE of 12.1%, although the total ROE would be capped at 11.63%, which is the upward bound of the proposed zone of reasonableness.

The IOUs also request risk-reducing incentive-based rate treatment for all five transmission projects, including: 1) a hypothetical capital structure of 60 % equity and 40% debt; 2) recovery of all prudently incurred costs that are not capitalized and included in CWIP;[4] and, 3) preauthorization to recover prudently incurred abandoned plant costs due to circumstances beyond NY Transco's control.

[4] The IOUs also seek to include 100% of CWIP in rate base for the two proposed AC Upgrade projects, which are described in the following section.

## II. NYPSC Planning Proceedings

### A. Generation Retirement Contingency Planning

In November 2012, the NYPSC commenced a proceeding to develop a contingency plan to address the reliability deficiency of approximately 1,450 MW that would arise from the shut-down of 2,040 MW in generating capacity at the Indian Point Energy Center (IPEC). Con Edison, NYSEG, and NYPA subsequently proposed three transmission projects, referred to as the TOTS, which were compared against other transmission and generation projects submitted through a "Request for Proposals" (RFP) process.

The TOTS include two Con Edison proposals, which are referred to as the Ramapo to Rock Tavern line (Ramapo/Rock Tavern) and the Staten Island Unbottling (Staten Island) projects. At the time the NYPSC accepted these projects, they were estimated to cost $123.1 million and $248 million, respectively. The third project was proposed by NYSEG and NYPA, and is called the Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring (Marcy/Fraser) project. NYSEG and NYPA's combined costs were estimated at $76 million.

In November 2013, the NYPSC issued an order accepting an IPEC Reliability Contingency Plan, which is attached as Appendix A. The NYPSC found the TOTS would "contribute at least 600 MW toward the reliability relief which may be necessary if

IPEC is shut down," yet the projects would offer "net benefits for ratepayers even if IPEC were to operate beyond December 2015."[5] Importantly, in accepting the TOTS for development, the NYPSC emphasized the significance of the project cost estimates that were provided. Specifically, the NYPSC indicated:

> the cost estimates provided by Con Edison, NYSEG, and NYPA for these projects were provided so that the projects could compete with the other projects that responded to the NYPA RFP. As such, the TOTS projects were proposed in a competitive environment, which we believe should have induced Con Edison, NYSEG, and NYPA to propose the most competitive price possible. We expect to retain the benefits of this competitive process for ratepayers. Therefore, Con Edison, NYSEG, and NYPA should hold their investment costs for these projects to the estimates which they supplied when the project proposals were made....[6]

The NYPSC further expressed its expectations in supporting the cost allocation approach proposed by NY Transco, which the IOUs presented in their Filing. In particular, the NYPSC indicated that there are:

> several factors which weigh in favor of utilizing the proposed NY Transco approach for the three TOTS projects. Specifically, the NY Transco allocation was voluntarily developed and approved by all of the NYTOs. We acknowledge that the NYTOs have achieved a significant milestone in reaching this consensus, as they have solved a problem that can hinder the

[5] Case 12-E-0503, Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans, Order Accepting IPEC Reliability Contingency Plans, Establishing Cost Allocation and Recovery, and Denying Requests For Rehearing (issued November 4, 2013) (IPEC Contingency Plan Order), pp. 22, 24.

[6] IPEC Contingency Plan Order, p. 25.

construction of infrastructure across utility service territories.[7]

B. <u>AC Transmission Congestion Relief</u>

The other two transmission projects, which are referred to as AC Upgrade projects, were proposed by the IOUs in the NYPSC's pending proceeding to evaluate potential solutions for reducing the persistent congestion that exists on the Central East and Upstate New York/Southeast New York (UPNY/SENY) electrical interfaces. On December 16, 2014, the NYPSC issued an order, attached as Appendix B, which lays out a process for considering whether to accept a transmission solution, such as the AC Upgrade projects. In particular, the NYPSC intends to undertake a comparative evaluation process that results in a determination in August-September 2015 regarding a preferred project(s) that may be coordinated with the NYISO transmission planning process that considers transmission needs driven by Public Policy Requirements identified by the NYPSC. In the event a transmission project is ultimately approved, the order also identifies the NYPSC's preferred approaches for cost recovery, cost allocation, and risk-sharing.

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7 IPEC Contingency Plan Order, p. 33.

## DISCUSSION

### I. FERC Should Conduct A Hearing to Ensure NY Transco's Requested Incentive Ratemaking Treatment and Total ROE Are Just and Reasonable

The NYPSC maintains that the IOU's Petition for incentive ratemaking treatment, a 10.6% base ROE, plus 150 basis point adders in ROE incentives, would result in unjust and unreasonable rates. As a result, the Petition will unreasonably burden New York transmission ratepayers. The relief requested is clearly excessive and unreasonable given: 1) a capital structure based on 50% equity is sufficient to attract capital investments; 2) the requested application of incentive ratemaking for CWIP and abandoned plant sufficiently reduces development risks; 3) the IOUs have extensive experience in transmission development; 4) the IOUs/NY Transco otherwise face minimal risks; 5) the IOUs already possess the necessary siting approvals for the TOTS; and, 6) current low interest rates support the likelihood of favorable financing terms.

An evidentiary hearing is needed to allow interested parties an opportunity to cross-examine the IOUs on their factual claims with respect to the requested incentives and ROE. For example, the IOU's selection of the proxy group should be examined in detail to determine if it is appropriate to include ITC Holdings Corp. within the proxy group. Given that ITC Holdings Corp. has a high ROE and a growth rate that may not be sustainable, it is highly questionable as to whether it should have been included in the proxy group. In the event the company is selected for the proxy group, FERC should recognize that it may not be necessary to include any ROE incentive adders to an already enhanced base ROE.

The Commission should also afford interested parties an opportunity to cross-examine the IOUs regarding their proposed zone of reasonableness of 6.25% and 11.63%. The NYPSC's initial analysis, subject to update, raises important questions of fact and suggests a lower range of approximately 5.90% to 11.45% is reasonable and supported by FERC's discounted cash flow (DCF) methodology.[8] This zone of reasonableness, as detailed in Appendix C, was determined using a national proxy group of 41 companies that met FERC-established criteria, while excluding two low-end outliers.[9]

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8 Appendix C, p. 3.

9 Each company in the national proxy group met the following Commission criteria: (1) the company must be a domestic publicly-traded electric utility followed by the Value Line Investment Survey (Value Line); (2) the company must have Moody's and S&P investment grade bond ratings (at least BBB-/Baa3); (3) the company must have IBES-determined growth rate estimates (obtainable from Yahoo.Finance.com); (4) the company must not be known to be a recent party to significant merger and acquisition activity; and,(5) for the past 6 months, the company must have consistently paid dividends without any cuts to their dividends.

A. **<u>NY Transco's Proposed Hypothetical Capital Structure Is Excessive and Unnecessary</u>**

The IOUs request a hypothetical capital structure for NY Transco consisting of 60% equity and 40% debt for the first five years of its operation. The IOUs claim that this equity ratio is necessary to assure access to capital because the other requested incentives do not fully mitigate the risks and challenges of its projects. According to the IOUs, NY Transco will operate as a stand-alone company with no previous operating history, weak initial cash flow, and high capital expenditures incurred for complex projects.

The NYPSC's analysis demonstrates that the IOU's proposed hypothetical capital structure with a 60% equity/40% debt ratio is excessive, and that a common equity ratio of no more than 50% is reasonable and would allow NY Transco to attract sufficient capital. Based on the NYPSC's review of a national proxy group of 41 transmission and distribution companies, which is presented in Appendix C, the 2013 year-end average common equity ratio was 46.88%.[10] This common equity ratio was adequate to support a Moody's average bond rating of "Baa1" and an S&P rating of "BBB+." Similarly, the proxy group presented by NY Transco had an average and median common equity ratio of 47.68% and 48.63%, respectively, which supported the

[10] Appendix C, p. 5.

same Moody's average bond rating of "Baa1" and S&P rating of "BBB+." These ratings allowed the proxy group companies to access capital at costs and terms that were reasonable.

As shown in Appendix C, electric transmission companies with S&P investment grade ratings ranging from "BBB" to "A-" were able to access an average debt amount of about $312.1 million at an average coupon of 3.90% in 2014.[11] This means that liquidity remains adequate for most transmission utility companies, and investor appetite for utility debt remains healthy, as characterized by their continuing subscriptions to financings at very attractive rates and with durations ranging from five to 30 years. The relative certainty of financial performance by utilities operating in an effective monopoly position under relatively predictable regulatory frameworks, while owning long-lived assets, continue to make the utility sector attractive to investors.

As a group, the IOUs currently have an average Moody's bond rating of "A3" and an average S&P rating of "A-." These ratings are supported by average and median common equity ratios of 53.32% and 52.01%, respectively (based on 2013 year-end financial data). Given this data, as shown at Appendix C, the NYPSC recommends a common equity ratio of no higher than 50%, based on a combination of the 2013 year-end average common

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[11] Appendix C, pp. 8-9.

equity ratio of 46.88% and the six IOUs average common equity ratio of 53.32%.[12] This common equity ratio is reasonable and economical. More importantly, it is proven sufficient to allow transmission owners access to financial capital. To the extent current year-end financial data is available at the time of the Commission's decision, the Commission should update these common equity ratios.

### B. The IOU's Proposed Incentive Ratemaking Treatment Will Adequately Reduce NY Transco's Risks

The IOUs seek preauthorization to recover prudently incurred abandoned plant costs due to circumstances beyond NY Transco's control, and the ability to recover all project costs that are not capitalized and included in CWIP. The NYPSC supports these requested ratemaking treatments as a means for reducing the risks of Transco and avoiding the need for additional ROE incentive adders.[13] These ratemaking treatments also obviate the need for an assumed equity ratio greater than 50%. It should also be recognized that the establishment of a

[12] Appendix C, p 6.

[13] FERC should explicitly indicate that a section 205 filing would be required in the event that any such abandonment occurs. Such a filing is necessary to determine if the costs expended on the abandoned project were prudently incurred and whether or not it is ultimately just and reasonable to recover those costs from ratepayers.

formula rate that will be updated annually will eliminate the risk that NY Transco will experience sustained under-earnings.

### C. The IOU's Proposed ROE Incentive Adders Are Excessive and Unnecessary

The IOUs seek 150 basis points of ROE incentives to fully offset the perceived risks and challenges faced by NY Transco in pursuing the transmission projects. The NYPSC is concerned that NY Transco's proposed ROE incentives are overstated, which will unreasonably raise transmission costs and, in-turn, unnecessarily increase the cost of electricity to New York ratepayers. A further concern is that the IOUs requests for incentive ratemaking treatment and compensation for perceived risks are so excessive as to shield NY Transco's shareholders entirely from risk, at the expense of ratepayers.

As required under FERC Order 679, eligibility for incentive ratemaking requires a demonstration that: 1) "the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion"; 2) "the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant" (including an explanation and support to evaluate each element of the package and interrelationship of all elements of the package); and, 3) the "resulting rates are just and reasonable."[14] While the NYPSC does not take issue with the first requirement, the IOUs have failed to make the required showing with respect to the other two prerequisites to justify their requested return.

Moreover, the petitioners failed to demonstrate the impact of the three ROE incentive adders on the $670 million net present value of cost savings over the expected 40 year life of the TOTS projects, which the NYPSC relied upon.[15] For example, it is likely that the $670 million net present value of net benefits of the projects could be wiped out once the ROE incentive adders of 150 basis points are paid, or if cost-overruns during construction occur, thus resulting in a higher cost to ratepayers.

The NYPSC offers the following critiques and assessments with respect to the specific proposed ROE incentive adders.

1. **Transco Formation**

The IOUs request a 50 basis point adder for forming a transmission-only entity that will focus exclusively on developing and operating needed transmission facilities to

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[14] 18 CFR 535.35; Docket No. RM06-4-000, Promoting Transmission Investment through Pricing Reform, Order 679 (issued July 20, 2006) (Order 679); reh'g granted, Order 679-A (issued December 22, 2006) (Order 679-A); reh'g granted, Order on Rehearing (issued April 19, 2007).

[15] IPEC Contingency Plan Order, p. 24.

relieve chronic or severe grid congestion that have been demonstrated to cause cost impacts for consumers. The IOUs believe this incentive is justified because NY Transco's projects are expected to unlock location constrained generation resources that previously had limited or no access to the wholesale electricity markets. The IOUs also suggest that their transmission projects will address public policy needs, including facilitating the ability of New York State to meet long-term federal and State clean energy goals and aid economic development throughout the State.

The Commission should find that the risks faced by NY Transco will be similar to those faced by a typical transmission and distribution company. The IOUs affiliated with NY Transco have significant experience and an expertise in developing transmission projects. The IOUs bring this experience and expertise, as well as their financial stability, to the operation of NY Transco. These factors all assist in reducing the risks associated with operating a Transco. The NYPSC is unaware of any adverse changes in financial condition resulting from these utilities being engaged in transmission activities. Accordingly, a 50 basis point adder for forming a Transco is unnecessary and excessive.

## 2. Transco Risks

The IOUs seek a 50 basis point adder to compensate NY Transco for any significant development, construction, regulatory, and financing risks. The IOUs suggest this incentive is justified because of NY Transco's business risk.

The NYPSC disputes that such incentive is needed to address the risks associated with operating NY Transco, for four reasons. First, there is minimal financing risk given that the capital structure recommended by the NYPSC will support an investment grade bond rating. Second, the ongoing need for sustainable transmission infrastructure will minimize the NY Transco's regulatory risk. Third, given NYPSC siting approval, favorable regulatory treatment, including pre-authorization to recover 100% of abandoned costs that are prudent, the risks should be insignificant. Fourth, the base ROE adequately accounts for any project risks and challenges.

The NYPSC notes that the proxy group of transmission and distribution electric companies that it analyzed in reviewing the IOU's proposed hypothetical capital structure indicates that 50% common equity ratios support access to capital at costs and terms that are reasonable. Because the risk-reducing measures such as CWIP and the guaranteed recovery of abandoned plant costs should be approved, as noted above, there is no justification for awarding this additional incentive to NY Transco. Moreover, through the formation of a joint venture involving the six IOUs, the project risk is diversified, leaving the need for this 50 basis point adder unjustified. The IOUs failed to explain why the net benefits to customers would not have been achieved absent this ROE adder.

### 3. ISO Participation

The IOUs request an additional 50 basis points for NY Transco to reward it for becoming a member of the NYISO and turning over operational control of its transmission facilities to the NYISO. NY Transco believes that this incentive is consistent with the Commission's policy to incentivize utilities to place their transmission facilities under the control of an ISO.

The NYPSC recommends that the 50 basis points adder for NYISO membership should be rejected because all of the companies in the NY Transco are already NYISO members. When the IOUs first ceded their transmission assets to NYISO control, the companies were engaged in NYPSC-approved rate plans that compensated them for the divestiture of their generating assets and transferring operational control of their bulk transmission assets to the NYISO. This compensation achieved the Commission's goal of incentivizing the creation of the NYISO and for the IOUs to transfer operational control of their transmission facilities.

It should also be noted that the TOTS are essentially modifications of NYTO facilities already under the operational control of the NYISO. Since NY Transco is essentially an extension of the IOUs themselves, and these companies have already been compensated for joining the NYISO, it would be an unreasonable double count to bestow this incentive upon NY Transco. It is also not appropriate to award an ROE incentive for transferring operational control to the NYISO since such action would occur even without an incentive. Therefore, a 50 basis point adder for joining an ISO is both unnecessary and unreasonably excessive. If granted, the adder would be a windfall to NY Transco owners at the expense of New York transmission customers.

## II. FERC Should Conduct A Hearing To Ensure The NY Transco's Proposed Cost Allocation And Recovery For The TOTS Is Just and Reasonable

The IOUs wrongly claim the NYPSC has "endorsed" their proposed allocation of costs.[16] While the NYPSC initially supported the IOU's proposed allocation related to the TOTS, that support was based on a conceptual framework for NY Transco that included the voluntary participation of all NYTOs, including LIPA and NYPA, covering a suite of 18 transmission projects throughout the State. However, given that the IOUs propose to form NY Transco without LIPA and NYPA, the IOUs now

[16] Petition, p. 9.

seek to impose an involuntary allocation of costs upon them. The Commission should recognize that an involuntary allocation of costs covering a limited suite of projects is contrary to the factors the NYPSC relied upon in supporting the NY Transco proposal, and may not result in a just and reasonable allocation of costs.

The involuntary allocation of costs to LIPA and NYPA raises significant questions regarding the reasonableness of the IOU's proposal to allocate a fixed percentage of costs to each of the NYTOs. The NYPSC's order accepting the TOTS supported the Commission's "beneficiaries pay" principle and noted that the benefits associated with those projects would likely accrue downstate, although statewide reliability benefits would also likely result. Now that the conceptual premise for the NYPSC's determination is no longer in place, factual questions regarding the reasonableness of allocating costs based on a NYTO-specific methodology that initially presumed a suite of 18 projects require that FERC conduct a hearing.

The NYPSC's selection of the TOTS was also premised upon specific cost estimate bids provided through a competitive process and other key assumptions, as detailed in Appendix D. The NY Transco should not be allowed to recover additional costs that could undermine the net benefits that the NYPSC identified as an essential element in accepting the TOTS projects for development. In particular, the IOUs ignore the estimated costs NYPA would incur for a portion of a project that would be undertaken with NYSEG. The Petition indicates that NYSEG's costs will now be approximately $66 million, while the entire project cost, including NYPA's share, was $76 million when presented to the NYPSC for selection. Similarly, the IOUs present costs for the Staten Island project that are much higher than what was presented to, and relied upon by, the NYPSC in accepting the IPEC Reliability Contingency Plan that included the TOTS. Because the cost estimates were derived through a competitive process, the NYPSC found that cost recovery should be limited to actual costs or to the estimates presented, whichever is lower.

The NYPSC requests the Commission's assistance in ensuring the integrity of the NYPSC's competitive selection process, and that ratepayers retain the benefit of this process, by limiting the IOUs recovery of costs above their estimates relied upon by the NYPSC. Alternatively, the Commission should implement a risk-sharing mechanism between NY Transco's shareholders and ratepayers for cost overruns above the estimates relied upon by the NYPSC. The NYPSC adopted such a risk-sharing mechanism in its on-going proceeding to evaluate the AC Upgrades projects. For example, the NYPSC indicated that the developer should bear 20% of the actual cost over-runs, while ratepayers would bear 80% of those costs. If actual costs fall below the bid, the developer would retain 20% of the savings. In addition, as a component of the risk-sharing model, if the developer is seeking incentives from FERC above the base ROE otherwise approved by FERC, the developer should not receive any incentives above the base ROE on any cost overruns over the bid price. Applying this risk-sharing model, the bid price would cap the costs that may be proposed to FERC for incentives. The initial bid price, however, could be updated to reflect additional identifiable and verifiable costs associated with regulatory-imposed modifications and mandates, the cost of which the developer could not have anticipated in formulating the initial bid price. These additional costs would need to exceed a materiality threshold of 5% above the initial bid price.

The NYPSC contends this approach comports with FERC's prior acceptance of "specific, binding cost control measures that the transmission developer agrees to accept, including any binding agreement by the transmission developer and its team to accept a cost cap that would preclude project costs above the cap from being recovered...."[17]

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[17] Docket Nos. ER13-103-000 et al., California Independent System Operator Corporation, Order on Compliance Filing (issued April 18, 2013), 143 FERC ¶61,057, ¶233.

### III. FERC Should Reject The NY Transco's Proposed Rate Treatment For Proposed AC Upgrade Projects

The NYPSC is currently considering whether the IOUs' proposed AC Upgrade projects should be developed further. The NYPSC plans to address later this year whether the IOUs or alternative projects should be evaluated under the NYISO's public policy planning process. However, it is premature at this time to authorize rate treatment for the AC projects.

The NYPSC is also concerned that adopting the IOUs' approach will tilt the playing field against non-incumbent transmission developers that propose alternatives in competition with the IOUs. If the IOUs are afforded preferential rate treatment in a competitive process, while their competitors are not, the playing field will not be level.

## CONCLUSION

In accordance with the discussion above, the NYPSC respectfully requests that the Commission conduct a hearing to resolve the numerous questions of fact presented in the Petition. An evidentiary hearing will help ensure that the total ROE, rate treatment, cost allocation and cost recovery with respect to NY Transco are just and reasonable.

Respectfully submitted,

Kimberly A. Harriman

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General Counsel
Public Service Commission
of the State of New York
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Dated: January 16, 2015
Albany, New York

## CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated: Albany, New York
January 16, 2015

David G. Drexler
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# APPENDIX A

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 12-E-0503 - Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans.

# ORDER ACCEPTING IPEC RELIABILITY CONTINGENCY PLANS, ESTABLISHING COST ALLOCATION AND RECOVERY, AND DENYING REQUESTS FOR REHEARING

Issued and Effective: November 4, 2013

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on October 17, 2013

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Patricia L. Acampora
Garry A. Brown
Gregg C. Sayre
Diane X. Burman

CASE 12-E-0503 - Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans.

ORDER ACCEPTING IPEC RELIABILITY CONTINGENCY PLANS, ESTABLISHING COST ALLOCATION AND RECOVERY, AND DENYING REQUESTS FOR REHEARING

(Issued and Effective November 4, 2013)

BY THE COMMISSION:

## INTRODUCTION

This proceeding was commenced through a November 2012 Order that directed the development of utility plans to address the reliability concerns that may arise from the retirement of electric generating facilities.[1] In particular, the November 2012 Order recognized the significant reliability needs which could occur if the 2,040 MW of generating capacity at the Indian Point Energy Center (IPEC) were retired upon the expiration of

[1] Case 12-E-0503, Generation Retirement Contingency Plans, Order Instituting Proceeding and Soliciting Indian Point Contingency Plan (issued November 30, 2012) (November 2012 Order).

IPEC’s existing licenses.[2] Given the uncertainty regarding “whether Entergy will be able to obtain the necessary permits and approvals to keep [IPEC] operational over the long-term,” the Commission sought a reliability contingency plan addressing those potential reliability needs.[3] The November 2012 Order directed Consolidated Edison Company of New York, Inc. (Con Edison), as the transmission owner most directly affected by the closure of the IPEC, to develop such a plan in consultation with the New York Power Authority (NYPA), Department of Public Service Staff (DPS Staff), and other appropriate agencies.[4]

In response to the November 2012 Order, Con Edison and NYPA jointly submitted a filing on February 1, 2013 (Con Edison/NYPA February Filing). The Con Edison/NYPA February Filing, as described in more detail below, proposed an IPEC Reliability Contingency Plan whereby Con Edison, New York State Electric and Gas Corporation (NYSEG), and NYPA would pursue the initial development of three Transmission Owner Transmission Solution (TOTS) projects, while concurrently soliciting generation and transmission proposals (other than the TOTS projects) through a Request for Proposals (RFP) to be issued by NYPA. The Con Edison/NYPA February Filing further described an Energy Efficiency (EE)/Demand Reduction (DR) program to obtain 100 MW of peak demand reduction. The TOTS upgrades, the 100 MW

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[2] The IPEC, which is located in Buchanan New York, consists of two base-load nuclear generating units that are currently owned by Entergy Nuclear Indian Point 2, LLC, and Entergy Nuclear Indian Point 3, LLC (collectively, Entergy). The Nuclear Regulatory Commission’s licenses for IPEC Unit 2 and Unit 3 expire on September 28, 2013, and December 12, 2015, respectively.

[3] November 2012 Order, p. 3.

[4] On January 14, 2013, and prior to submitting their plan, a meeting was held by Con Edison and NYPA to provide their preliminary concepts for a reliability contingency plan, and to obtain input from interested stakeholders.

from EE and DR programs, and any projects accepted through the RFP process, were proposed as a portfolio to address a potential reliability need of approximately 1,450 MW that could arise in the 2016 summer period. Specifically, a June 1, 2016 reliability need date, when peak summer conditions could be expected to arise, was identified as an in-service date for projects that was consistent with the analysis performed as part of the 2012 Reliability Needs Assessment (RNA) conducted by the New York Independent System Operator, Inc (NYISO).[5]

The Con Edison/NYPA February Filing requested specific actions by the Commission, including: 1) an order in March 2013 requesting NYPA to issue an RFP for solutions to the potential energy reliability needs;[6] 2) an order in April 2013 authorizing the development of the 100 MW of EE and DR programs, the initial planning of the three TOTS projects, and the recovery of prudently incurred costs associated with planning the TOTS projects; and, 3) an order in September 2013 identifying a preferred set of transmission and/or generation projects for inclusion in the IPEC Reliability Contingency Plan, and making findings in connection with an authorization of cost allocation and cost recovery for such projects.[7]

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[5] The development of the June 2016 reliability need date, and of the extent of the potential need on that date, is discussed in more detail infra.

[6] The November 2012 Order, and the Notice Soliciting Comments issued on February 13, 2013, sought comments, by February 22, 2013, on the first requested action item (i.e., the issuance of the NYPA RFP, and related matters).

[7] The Con Edison/NYPA February Filing sought certain findings by the Commission, including findings that each of the TOTS projects would be a public policy project that meets the public policy requirements of New York State.

On March 15, 2013, the Commission issued an order that responded to the first requested action in the Con Edison/NYPA February Filing.[8] In particular, the March 2013 Order approved the proposal, subject to certain modifications, for NYPA to issue an RFP. The RFP was subsequently issued by NYPA on April 3, 2013, and responses to the RFP were received on or about May 20, 2013.

On April 19, 2013, the Commission responded to the second request in the Con Edison/NYPA February Filing, and approved, subject to conditions, Con Edison, NYSEG, and NYPA's preliminary planning related to the three TOTS projects.[9] While preliminary planning was approved for the TOTS, as described in the Con Edison/NYPA February Filing, the recovery of planning costs was capped at $10 million for an initial period until the TOTS projects were analyzed further.[10] In the April 2013 Order, Con Edison was also directed to work with the New York State Energy Research and Development Authority (NYSERDA) and NYPA, and to file a revised plan to secure permanent peak reduction from incremental EE and DR programs and other resources. Finally, the Order directed DPS Staff to propose a cost

[8] Case 12-E-0503, Generation Retirement Contingency Plans, Order Upon Review of Plan to Issue Request For Proposals (issued March 15, 2013) (March 2013 Order).

[9] Case 12-E-0503, Generation Retirement Contingency Plans, Order Upon Review of Plan to Advance Transmission, Energy Efficiency, and Demand Response Projects (issued April 19, 2013) (April 2013 Order). On February 20, 2013, a notice was published in the State Register, inviting comments on the second requested action items by April 8, 2013.

[10] At the time of the April 2013 Order, we declined to make the requested findings regarding consistency with public policy requirements, based on the unavailability of tariff provisions or procedures that could be applied. That conclusion, therefore, was without prejudice to a new request for findings, which could be made in this or another case before this Commission, or may be sought in another forum.

allocation and cost recovery mechanism for the Commission's consideration.

In response to the April 2013 Order, a revised plan for EE and DR programs was filed on June 20, 2013, by Con Edison and NYPA, in consultation with NYSERDA. The plan was comprised of 100 MW of EE and DR, which would be pursued by Con Edison and NYSERDA, and 25 MW of Combined Heat and Power (CHP) projects to be administered by NYSERDA (collectively, the 125 MW Revised EE/DR/CHP Program). The 125 MW Revised EE/DR/CHP Program, along with 60 MW from other on-going projects identified by NYSERDA and NYPA, which had not been counted in the NYISO's 2012 RNA, were estimated to provide 185 MW of relief toward the potential reliability deficiency. DPS Staff also submitted a proposed cost allocation/cost recovery straw proposal on June 4, 2013 (DPS Staff June Straw Proposal). The 125 MW Revised EE/DR/CHP Program and the June Straw Proposal are discussed further below.

In this Order, we address, in part, the third and final requested action item in the Con Edison/NYPA February Filing by accepting a portfolio for inclusion in the IPEC Reliability Contingency Plan consisting of: 1) the three TOTS projects; and 2) the development of approximately 125 MW of EE/DR/CHP resources through the 125 MW Revised EE/DR/CHP Program. This portfolio, along with 60 MW from on-going EE, DR, and CHP activities, makes a total contribution of 185 MW from EE, DR, and CHP programs towards the potential reliability need for 1450 MW in June 2016.[11] We anticipate that the TOTS will contribute at least an additional 600 MW towards that need.

As noted above, the April 2013 Order approved the issuance of an RFP seeking proposals for generation or non-TOTS transmission projects which could be included in the IPEC Reliability Contingency Plan portfolio. In response to the RFP, a significant number of proposals were received, and these proposals have been evaluated by DPS Staff with the assistance of a consultant, The Brattle Group, Inc. (Brattle).

For the time being, however, we agree with DPS Staff's recommendation to defer the choice of which, if any, of the proposals responding to the NYPA RFP should be included in the IPEC Reliability Contingency Plan portfolio. We leave this issue open in light of the uncertainties presently affecting the wholesale generation markets. First, in the coming months, it is possible that the NYISO will establish a new Installed Capacity (ICAP) Zone in the Lower Hudson Valley to meet Locational Capacity Requirements. Second, the NYISO is developing new "Demand Curves" for use in setting ICAP prices in the NYISO-administered markets. Both of these actions are very likely to increase ICAP prices that generators can expect to

[11] In connection with the filing of the 125 MW Revised EE/DR/CHP Program, additional DR and CHP projects providing a total of 60 MW have been identified, which are expected to be available by the summer 2016, but were not accounted for in the NYISO's 2012 RNA. For purposes of evaluating the portion of the reliability gap which is met by new EE, DR, and CHP activities, we will count the estimated results of these programs in the analysis. The programs providing these 60 MW, however, are already on-going and have an identified source of funding associated with them, so no action in this Order is needed for their implementation. The 60 MW from these programs breaks down as: (a) an additional 15 MW of peak demand reductions as part of a separate NYPA Build Smart NY Program, (b) an additional 15 MW of on-going CHP projects at NYPA, and (c) 30 MW of CHP projects through a NYSERDA program which has already been approved by the Commission.

receive in the Lower Hudson Valley.  At the same time, there are several merchant generating units, with a combined capacity of approximately 1,500 MW, which could serve this market, but have either been mothballed and are waiting to return to service if economic conditions improve, or have been subject to a forced outage or have been derated and require repair.  With the potential to participate in a higher revenue stream, some of the owners of these units could decide in the near future to bring their units back into service.  If so, these units would contribute to meeting the reliability needs, thus reducing the amount of resources necessary to include in the IPEC Reliability Contingency Plan portfolio.

As discussed below, we agree with DPS Staff’s recommendation to include the TOTS projects and the EE, DR, and CHP projects described above in the portfolio of projects accepted for inclusion in the IPEC Reliability Contingency Plan. If accepted now and, if timely implemented, the TOTS projects and the 125 MW Revised EE/DR/CHP Program provide a significant portion of the resources needed to address the potential reliability needs in the event IPEC is retired in December 2015. This Order accepts this limited suite of projects as the appropriate least-cost and least-risk portfolio for the IPEC Reliability Contingency Plan at the present time.

This Order also addresses the method by which the costs associated with implementing the herein accepted components of the IPEC Reliability Contingency Plan should be allocated, and the mechanisms by which those costs should be recovered.  Finally, we address the Requests for Rehearing of the March 2013 Order and the April 2013 Order.  For the reasons discussed below, we deny these requests.

## BACKGROUND

### Con Edison/NYPA February Filing

#### A. TOTS Projects

The first component of the contingency plan proposed in the Con Edison/NYPA February Filing consisted of three TOTS projects that Con Edison and NYPA asserted could be implemented by the summer of 2016. In particular, Con Edison described its plan to develop a second Ramapo to Rock Tavern transmission line (Ramapo/Rock Tavern), and a Staten Island Unbottling (Staten Island) project. The third project, referred to as the Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring (Marcy/Fraser) project, would be developed by NYPA and NYSEG.[12]

According to the Con Edison/NYPA February Filing, as updated on May 20, 2013, two of the TOTS projects (i.e., the Ramapo/Rock Tavern line and the Marcy/Fraser project) would increase the import capability into Southeastern New York by reducing the constraint on the Upstate New York/Southeast New York interface. This means that underutilized upstate capacity would be able to provide increased levels of energy to the downstate area and this increased capability would provide a reliability benefit. The third proposed TOTS, i.e., the Staten Island unbottling project, is designed to make generation on Staten Island, which is currently bottled, available to the grid and deliverable to Con Edison’s Gowanus and Farragut transmission substations.[13]

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[12] The three TOTS are discussed in detail in Exhibits B, C, and D of the Con Edison/NYPA February Filing, and the update filed on May 20, 2013.

[13] Generation that is “bottled” is physically interconnected, but cannot provide its full output to the grid due to transmission limitations.

The Con Edison/NYPA February Filing sought full recovery of the costs, including any associated contractual cancellation costs, incurred by Con Edison and NYPA for these projects. Con Edison and NYPA provided estimates of the costs to halt the TOTS projects at selected intervals and of the costs to complete each of these projects. The total cost to complete these projects was initially estimated at approximately $511 million. Based on updates filed on May 20, 2013, the cost of the Staten Island project was revised downward, making the total estimated cost of the three TOTS projects approximately $447 million. According to the Con Edison/NYPA February Filing, the TOTS projects would ultimately be transferred to and owned by an entity identified as the "New York Transmission Company" (NY Transco).

Con Edison, together with the other New York investor-owned transmission companies, and NYPA and the Long Island Power Authority (LIPA) (collectively the New York Transmission Owners or NYTOs), are active participants in the process of creating the NY Transco. The NY Transco's purpose and structure are intended to address and overcome planning and cost allocation issues which have, to date, impeded the development of economic transmission projects. The NY Transco would be a new entity formed for the express purpose of developing transmission projects in the State. However, while the NY Transco has not yet been formed, on May 30, 2012, and in response to the New York State Energy Highway Request for Information, the NYTOs identified eighteen transmission projects throughout the State that the NY Transco could develop.[14] The identified projects included the three TOTS projects under consideration here.

B. EE/DR/CHP Programs

The second component of the IPEC Reliability Contingency Plan, as initially presented by Con Edison and NYPA, included a targeted program to achieve 100 MW of permanent peak demand reduction by the summer of 2016. NYPA also identified 15 MW of on-going CHP projects that would be placed in-service by the summer of 2016.

The EE and DR components of the Con Edison/NYPA February Filing were subsequently supplanted with the 125 MW Revised EE/DR/CHP Program proposed by Con Edison and NYSERDA, in consultation with NYPA. The 125 MW Revised EE/DR/CHP Program, filed on June 20, 2013, seeks approval for 100 MW of peak EE/DR and fuel switching projects, which would be coordinated by Con Edison and NYSERDA, along with a 25 MW expanded CHP program that would be administered by NYSERDA.

The EE and DR components of the 125 MW Revised EE/DR/CHP Program would be located within Con Edison's service territory, and are broken down into 44 MW for load management, 40 MW for permanent demand reduction, and 16 MW for fuel switching, for a total of 100 MW. These projects are estimated to cost $219 million, and these costs are proposed to be

[14] See, http://www.nyenergyhighway.com/RFIDocument/transmission/index-2.html. The 18 projects identified by NY Transco could result in an estimated total investment of $2.9 billion in upgrades across the New York State transmission system. Neither the creation of, nor the formation of, nor any specific property transfer to the NY Transco is under review in this Order.

recovered through a surcharge on Con Edison's delivery customers.[15]

The Revised EE and DR components would be jointly implemented by Con Edison and NYSERDA, and are expected to result in a "single point of entry for all participants," with a single application process. These programs would focus on large customers located within Con Edison's service territory. Targeted customers would include: (1) customers with high peak demand; (2) project developers with potential large scale projects; (3) prior or existing Energy Efficiency Portfolio Standard participants that may be willing to expand the scope and depth of projects; and (4) customers capable of switching electric summer air conditioning load to steam or gas.

The Revised EE/DR/CHP Program also included a NYSERDA proposal for an Expanded NYSERDA CHP component for the Program. This aspect of the Program is designed to achieve 25 MW of load reduction. The total cost to ratepayers of the 25 MW Expanded NYSERDA CHP Program is expected to be $66 million, which is broken down to include: 1) $40 million for customer incentives; 2) $16 million for Outreach Assistance Contractor activities; and, 3) $10 million for administrative functions such as NYSERDA staff salaries and State Cost Recovery Fee and Program Evaluation tasks. The total cost for the 125 MW of projects proposed for acceptance in the 125 MW Revised EE/DR/CHP Program would be approximately $285 million.

As part of the filing that included the 125 MW Revised EE/DR/CHP Program, NYSERDA indicated that the 25 MW of proposed CHP projects was in addition to the CHP projects that the

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[15] The surcharge would exclude NYPA's governmental customers who receive delivery service under Con Edison's PSC NO. 12 – Electricity, since they already participate in the NYPA Build Smart NY Program.

Commission previously approved.[16] DPS Staff verified with NYSERDA that 30 MW of these previously approved CHP projects would be operational in Con Edison’s service territory by June 2016, and that they were not included in the NYISO’s 2012 RNA. In addition, NYPA identified an additional 15 MW that would be achieved under NYPA’s Build Smart NY program, which were not identified in the NYISO’s 2012 RNA but would be in-service by the summer of 2016. These MW reductions would come from a mix of efficiency gains at state agencies and authorities, wastewater treatment plants in New York City, and campus-wide American Society of Heating, Refrigerating and Air Conditioning Engineers-Level II audits. All NYPA Energy Efficiency Program projects are funded through NYPA low-cost financing that is recovered directly from program participants. As such, the cost of implementing these projects would not be funded through utility tariff charges.

Taken together, all of these projects, including the 15 MW of ongoing CHP projects NYPA identified in the Con Edison/NYPA February filing, would contribute toward meeting the calculated reliability deficiency needs.[17] Cumulatively, the 125 MW of projects proposed in the Revised EE/DR/CHP Program, and

[16] The Commission’s previous approval was in Case 07-M-0548, Energy Efficiency Portfolio Standard – System Benefit Charge IV, Order Modifying Budgets and Targets for Energy Efficiency Portfolio Standard Programs and Providing Funding for Combined Heat and Power and Workforce Development Initiatives (issued December 17, 2012).

[17] As noted above, NYSERDA and NYPA have identified other programs which have already been approved and are funded, but the results of which have not been counted in the NYISO RNA. These programs should contribute approximately 60 MW towards the reliability goal associated with the IPEC Reliability Contingency Plan. See note 11, supra.

the 60 MW from on-going projects[18], would contribute 185 MW toward the potential reliability deficiency need.

On July 17, 2013, a notice was published in the State Register, inviting comments on the Revised EE/DR/CHP Program. Various comments were received by the deadline of September 3, 2013.

DPS Staff Cost Allocation/Cost Recovery Proposal

In response to the April 2013 Order, DPS Staff filed the June Straw Proposal, which described a methodology as to how the costs associated with implementing the transmission or generation solutions that are ultimately part of the IPEC Reliability Contingency Plan could be allocated and recovered from retail ratepayers.  At the same time, DPS Staff also provided and sought comments on a draft Reimbursement Agreement prepared by NYPA, which NYPA described as “a necessary component of the mechanism that will be needed to ensure full recovery of costs incurred in connection with the [TOTS] and with generation project(s), if any, selected pursuant to the April 3, 2012 [RFP].”

DPS Staff’s June Straw Proposal sought to allocate costs by applying a “beneficiaries pay” principle, whereby the ratepayers that receive the reliability benefits from the IPEC Reliability Contingency Plan would be assigned a proportionate cost recovery responsibility.  The June Straw Proposal also attempted to maintain consistency, to the extent practicable, with the NYISO’s tariff provisions for allocating the costs of a transmission solution selected to fulfill a need identified in a NYISO Reliability Needs Assessment.

Pursuant to the Notice of Second Technical Conference and Revised Comment Schedule, issued on July 2, 2013, initial comments were sought by July 22, 2013, and reply comments were

[18] See, supra at note 11.

sought by August 5, 2013. Several comments were received in response to this notice.

## DISCUSSION

### Statutory Authority

With this Order, the Commission accepts a Reliability Contingency Plan that identifies a portfolio of specific transmission and EE/DR/CHP projects that, when taken together, will significantly reduce New Yorker's vulnerability to the costs and disruptions that could occur upon the retirement of IPEC Unit 3 in December 2015. In addition, the Order establishes the methods and mechanisms for the allocation and recovery of the costs and benefits associated with the implementation of the IPEC Reliability Contingency Plan.

Comments have been received in this proceeding in response to several notices seeking comments. These notices are summarized, along with the comments, in Appendix A to this Order. Some commenters expressed concern that the DPS Staff's June Straw Proposal for allocating costs would intrude into Federal Energy Regulatory Commission (FERC)-regulated markets, and would interfere with NYISO operating and planning processes, as well as unnecessarily duplicate, preempt, or nullify portions of the NYISO tariff. Other commenters argued that FERC, and not the Commission, has jurisdiction over cost allocation. These commenters further argued that the Commission lacks authority under the Public Service Law (PSL) for establishing a cost allocation methodology, and that our jurisdiction has not been established on this issue. It is also noted that this Commission lacks jurisdiction over NYPA; that NYPA lacks the authority assumed in the June Straw Proposal; that the Commission has limited jurisdiction over LIPA; and finally, that FERC has exclusive jurisdiction over the proposed TOTS projects.

However, others claim that cost allocation has been delegated to the Commission under the NYISO's compliance filing pertaining to FERC's Order 1000.

Contrary to some parties' arguments, the Commission's authority to adopt and provide for the implementation of this IPEC Reliability Contingency Plan is well founded in the PSL. In particular, section 5(2) of the PSL provides the Commission with authority to "encourage all persons and corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources."[19] Moreover, section 66(5) of the PSL provides the Commission with authority to address reliability concerns by prescribing the "safe, efficient and adequate property, equipment and appliances thereafter to be used," whenever the NYPSC determines that the utility's existing equipment is "unsafe, inefficient or inadequate."[20] The Commission also has authority to "order reasonable improvements and extensions of the works, wires, poles, lines, conduits,

[19] Section 5(2) of the PSL has been held to confer "broad discretion" to promote energy conservation. See, Multiple Intervenors v. NYPSC, 166 A.D.2d 140 (3rd Dept. 1991). Furthermore, PSL §5(2) was determined to provide the Commission with jurisdiction to require utilities to file plans outlining how they would adapt to a competitive electric industry. See, Energy Association of New York State v. NYPSC, 169 Misc. 2d 924 (Supreme Ct. 1996)(noting that PSL §5(2) transformed "the traditional role of the Commission from that of an instrument for a simple case-by-case consideration of rates requested by utilities to one charged with the duty of long-range planning for the public benefit").

[20] PSL §66(5). "Electric corporations" are required to provide "such service, instrumentalities and facilities as shall be safe and adequate." PSL §66(1).

ducts and other reasonable devices, apparatus and property of...electric corporations and municipalities."[21] Other provisions of the PSL also provide the Commission with authority over reliability.[22]

Moreover, the Commission's authority to protect or enhance reliability, as it exercises here by accepting the IPEC Reliability Contingency Plan, is expressly preserved under the Federal Power Act. As stated therein, FERC's authority to establish reliability standards "shall [not] be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any [FERC-approved] reliability standard, except that the State of New York may establish rules that result in greater reliability within that State, as long as such action does not result in lesser reliability outside the State than that provided by the [FERC-approved] reliability standards."[23] We find that the IPEC Reliability Contingency Plan usefully defines measures needed to ensure safety, adequacy, and reliability, and may result in greater reliability in New York than would otherwise exist under the FERC-approved reliability standards. Accordingly, our

[21] PSL §66(2). The NYPSC has continuing jurisdiction over the "construction, operation and maintenance of all utility transmission lines." See, Matter of Stannard v. Axelrod, 100 Misc.2d 702 (Sup. Ct. Broome Co. 1979) (dismissing petition challenging the NYPSC's Order approving a 345 kilovolt transmission line).

[22] See, PSL §§25(4) and 25-a(5) (allowing the NYPSC to impose penalties upon a public utility that fails to comply with regulations related to reliability); see also, PSL §126(1)(d) (providing that before the NYPSC may site a major electric utility transmission facility, the Commission must find that such facility "will serve the interests of electric system economy and reliability").

[23] 16 U.S.C. §824o(i)(3).

authority to accept the IPEC Reliability Contingency Plan is not preempted by FERC or the NYISO planning process.

In addition, the Commission has authority to ensure that “[a]ll charges made or demanded by any...electric corporation or municipality for…electricity or any service rendered or to be rendered, shall be just and reasonable and not more than allowed by law or by order of the commission.”[24] As the April 2013 Order stated, the Commission possesses the “authority to develop a retail rate recovery mechanism that provides for the jurisdictional utilities to collect payments from their ratepayers for reliability-related activities.”[25] The Commission also concluded that “this funding may be used to support actions taken by NYPA in support of their reliability-related activities undertaken in conjunction with the Indian Point Contingency Plan.”[26] The Commission further noted that it was not “asserting jurisdiction over NYPA, the rates NYPA charges its customers, or wholesale transmission rates established by FERC.” We conclude that these findings continue to adhere to the rulings in this Order.

With respect to cost allocation and recovery for the TOTS projects, however, we do not need to exercise our legal authority to decide the cost allocation and recovery issues. We understand from the NYTO’s comments that the TOTS project developers, together with the other NYTOs which are proposed members of the NY Transco, intend to seek cost recovery for the TOTS through FERC-approved tariffs. The TOTS developers have also indicated that they intend to propose a cost allocation methodology to FERC that is consistent with the methodology developed by the NYTOs in connection with the NY Transco

[24] PSL §65(1).

[25] April 2013 Order, p. 10.

[26] Id.

concept. We concur with the NYTOs that cost recovery and allocation through a FERC tariff are appropriate for these projects, and we intend to support such an application regarding the TOTS projects in so far as the application's proposed revenue requirement reflects the cost estimates and cost allocation methodology set forth in the NYTOs' filings in this proceeding. We urge the NYTOs to proceed as quickly as possible at FERC. In connection with that application, we will direct Con Edison, in consultation with NYPA, to supply a report on the progress of this application on or before June 30, 2014, and every six months thereafter.

Identification of Reliability Needs

The reliability implications of retiring IPEC have been well documented by the NYISO. While the NYISO assumed that IPEC was available in the 2012 RNA base case, it performed a further analysis with IPEC unavailable. This analysis found that "reliability violations would occur in 2016 if the Indian Point Plant were to be retired by the end of 2015."[27] The NYISO's 2012 RNA transmission security analysis indicated that, without Indian Point, already constrained transfer limits into Southeastern New York would be further aggravated.[28] In order to mitigate these overloads, the NYISO stated that compensatory megawatts would be needed in Zones G, H, I, J, or the western

[27] New York Independent System Operator 2012 Reliability Needs Assessment, Final Report, dated September 18, 2012, p. 42.

[28] Specifically, a transmission security analysis indicated overloaded conditions on the Leeds-Pleasant Valley and Athens-Pleasant Valley 345 kV lines, the Fraser-Coopers Corners and Rock Tavern-Ramapo 345 kV lines, and the Roseton-East Fishkill 345 kV line.

portion of Zone K,[29] amounting to 1,000 MW in 2016, noting that the amount of compensatory megawatts could increase depending on the location of the resource.[30]

Finally, the NYISO's 2012 RNA Indian Point Plant Retirement Scenario showed significant Loss of Load Expectation (LOLE)/resource adequacy violations if Indian Point were not available. Using the base case load forecast, the 2016 LOLE would be 0.48 days per year. This represented a significant violation of the 0.1 days per year criterion.[31]

The Con Edison/NYPA February Filing stated that it relied on the NYISO's 2012 RNA base case as the starting point for its analysis, noting that it is the NYISO's most recent evaluation of the bulk power system over the next ten years.[32] According to the filing, the base case was then updated by adjusting for known additions and retirements since the NYISO analysis was performed. Specifically, the NYISO's 2012 RNA base case was adjusted by adding 320 MW associated with the rescission of a mothball notice by Astoria Generating Company, L.P.'s Gowanus barges 1 and 4, and reducing the reliability deficiency need amount to reflect the effect of the 100 MW EE/DR

[29] The location of these Zones in New York State can be understood from a map at the NYISO website. See, http://www.nyiso.com/public/markets_operations/market_data/maps/index.jsp.

[30] New York Independent System Operator 2012 Reliability Needs Assessment, Final Report, dated September 18, 2012, p. 43.

[31] The New York State bulk power system is planned to meet a LOLE that, at any given point in time, is less than or equal to a involuntary load disconnection that is not more frequent than 0.1 days per year. In other words, the bulk power system is planned so that there is sufficient transmission and generation such that the LOLE is no more than once every 10 years.

[32] Con Edison notes that the RNA model and assumptions were a result of extensive stakeholder review.

peak load reduction program proposed in the Con Edison/NYPA February Filing. The results of the analysis, as indicated in the Con Edison/NYPA February Filing, showed a deficiency of 950 MW, as compared to the NYISO 2012 RNA analysis, which showed a deficiency of approximately 1,000 MW.

As Con Edison’s analysis was nearing completion, however, the retirement of the Danskammer generating facility was announced. Based on this announcement in January 2013, the effect of this retirement was estimated by Con Edison to increase the reliability needs by an additional 400-425 MW, making the total deficiency approximately 1,450 MW (or approximately 1,350 MW accounting for the effect of the initial proposed 100 MW EE/DR program).

In order to conduct an independent analysis and update of the reliability deficiency needs and to perform other work which would be useful for Staff’s Contingency Plan analysis, as directed in the March 2013 Order, DPS Staff obtained the consulting services of Brattle. Thereafter, DPS Staff directed Brattle to analyze the reliability needs that would attend the retirement of the IPEC at the end of 2015. DPS Staff indicated that the updated base case in the analysis should model NRG Energy, Inc’s Astoria Gas Turbine Units 10 and 11, which are expected to return to service.[33] Based on the analysis, DPS Staff confirmed the validity of the reliability needs identified in the Con Edison/NYPA February Filing, and that if IPEC Units 2 and 3 were to retire upon the expiration of its current licenses in 2013 and 2015, respectively, Southeast New York would not have enough capacity to avoid reliability violations in the summer of 2016.

[33] On June 7, 2013, NRG Energy, Inc. filed, in Case 05-E-0889, a notice of intent to return Astoria Gas Turbine Units 10 and 11 to service.

Contrary to parties' claims, we find that the various analyses performed of the potential reliability impacts associated with the retirement of IPEC provide a sufficient record and a rational basis to identify a reliability deficiency need of approximately 1,450 MW. We reject, however, parties' suggestions that the Commission should rely on the NYISO planning process to resolve these potential reliability needs, or that we should not plan for the contingency that IPEC may be retired.[34] As observed in the March 2013 Order, the NYISO's process currently assumes that IPEC will remain available, and therefore, it is not conducting the reliability contingency planning that we are conducting now.[35] We disagree that a reasonable planning approach under the circumstances should rely solely on market-based projects to appear, or that we should wait for the NYISO to "trigger" the need for the implementation of a reliability solution. In the event IPEC were unable to obtain the necessary consents and approvals to continue operating, or if Entergy could decide that continued operation of IPEC is not in its interest,[36] there would unlikely be sufficient time to address the resulting reliability needs.

The requirement that the projects included in the IPEC Reliability Contingency Plan meet a firm in-service deadline of June 1, 2016 comports with the NYISO's identified reliability

[34] We reiterate that the Commission is not making any determinations or taking any positions regarding the potential closure of the IPEC. See, November 2012 Order, fn 3.

[35] Under the NYISO's procedures, it will not assume that IPEC will be unavailable until Entergy, the owner and operator of the IPEC, provides a retirement notice.

[36] Entergy recently announced that due to economic factors it was retiring its Vermont Yankee nuclear reactor by the end of 2014, leaving regulators with as little as 16 months to address any reliability needs associated with the retirement. See, http://www.nytimes.com/2013/08/28/science/entergy-announces-closing-of-vermont-nuclear-plant.html?_r=0

need date under the “IPEC retirement scenario”. Therefore, the in-service requirement based on this date is consistent with the need to maintain safe and adequate service in the event IPEC is retired.

We also reject parties’ arguments that we have failed to reflect or accommodate market-based projects that are currently under development that could, when completed, contribute to meeting the identified reliability needs. The analysis of need took into account the most recent information available regarding proposed projects. To the extent any proposed projects have met the milestones established by the NYISO’s planning criteria for inclusion in the RNA base case, those projects were assumed to be available.[37]

Reliability Contingency Plan - Portfolio of Projects

The components of the IPEC Reliability Contingency Plan portfolio which we accept here will, according to DPS Staff’s analysis, contribute toward the potential reliability need, while offering net benefits for ratepayers even if IPEC were to operate beyond December 2015. DPS Staff opines that it is in the public interest to pursue these projects, regardless of the contribution they make to the IPEC Reliability Contingency Plan.[38] These projects include the three TOTS, which are estimated to provide at least 600 MW of reliability relief.. DPS Staff also recommends that we advance the proposal in the

[37] Indeed, our decision to defer considerations of the proposals submitted under the NYPA RFP arises from our understanding that market conditions are changing and may result in the development of market-based solutions. See supra at Section I.

[38] Con Edison referred to some of these projects as “no regrets” solutions to the retirement of the IPEC, meaning that the projects provide net benefits to ratepayers even if IPEC does not retire. See, Con Edison Filing of Supplemental Information Regarding its Ramapo to Rock Tavern Project (filed May 20, 2013).

125 MW Revised EE/DR/CHP Program to achieve the estimated 100 MW associated with EE and DR programs and approximately 25 MW from new NYSERDA CHP programs, as being consistent with the public interest and prior Commission decisions.[39]

A. TOTS Projects

Under DPS Staff's direction, Brattle examined the benefits and costs of the three TOTS projects. For this assignment, Brattle was asked to assume that IPEC continued to operate in order to determine whether potential net benefits would be associated with the TOTS projects under this more conservative assumption. To complete this evaluation, independent estimates of the resource cost savings were derived for each of the TOTS projects individually, as well as for all three combined.

To compare the TOTS costs and benefits, DPS Staff directed Brattle to convert the TOTS investment costs, as estimated by Con Edison and NYPA, into typical utility annual revenue requirements.[40] The energy resource cost savings were modeled using General Electric's Multi-Area Production Simulations (GE MAPS). Capacity resource cost impacts were estimated by Brattle and DPS Staff based on the modeling of NY's existing and proposed capacity markets.

The net benefits of the TOTS were calculated as the difference between resource cost savings and the total revenue requirements associated with the projects. Because annual revenue requirements begin at their highest level and decrease

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[39] See, Case 10-M-0457, et al., System Benefits Charge IV, Order Continuing the System Benefits Charge and Approving an Operating Plan for a Technology and Market Development Portfolio of System Benefits Charge Funded Programs (issued October 24, 2011).

[40] The revenue requirement includes estimates of on-going operation and maintenance costs and property taxes.

each year, and because resource cost savings were estimated to increase over time, estimated net savings increase over time. Thus, for the first 15 years of asset life, DPS Staff estimated net benefits to have a net present value (NPV) of approximately $260 million in 2016 dollars. For the full 40 years of rate recovery, the NPV of net benefits was estimated to be approximately $670 million.[41] DPS Staff indicates that if IPEC were retired, the estimated net benefits of the TOTS projects are expected to be higher.

From this information, DPS Staff concluded that, even if IPEC is not retired, the benefits of each TOTS project would be greater than its costs individually, and that the benefits for all three projects together would exceed their combined costs. DPS Staff also determined that the net benefits of the TOTS projects would be even greater if IPEC were not available in 2016 and beyond. Based on its findings that either scenario would provide net benefits for ratepayers, DPS Staff recommends that the TOTS projects should be pursued.

Implementing the three TOTS projects is expected to contribute at least 600 MW toward the reliability relief which may be necessary if IPEC is shut down. The reliability benefits of the Ramapo/Rock Tavern line and the Marcy/Fraser project would be created in greater or lesser measure whether or not IPEC retires. Further, even if IPEC does not retire, and the TOTS are not required to avoid reliability violations, the increased transfer capability from these projects would still provide economic benefits by supplying lower cost energy from upstate sources to downstate consumers. The Staten Island unbottling project responds to Con Edison’s in-city contingency planning needs, by decreasing the amount of in-city capacity Con

[41] DPS Staff notes that the estimates of annual benefits are more uncertain as more distant time periods are analyzed.

Edison needs to operate its system securely. This will also allow certain generators to run more, saving system resource costs.

We agree with DPS Staff’s recommendation and accept the inclusion of the three TOTS projects in the portfolio for the IPEC Reliability Contingency Plan. Significantly, DPS Staff’s analysis shows that the net benefits for ratepayers are available even if IPEC is not retired. We expect that Con Edison, NYSEG, and NYPA will proceed with the necessary permitting and approvals to achieve the June 1, 2016 in-service date for each project.

We emphasize that the cost estimates provided by Con Edison, NYSEG, and NYPA for these projects were provided so that the projects could compete with the other projects that responded to the NYPA RFP. As such, the TOTS projects were proposed in a competitive environment, which we believe should have induced Con Edison, NYSEG, and NYPA to propose the most competitive price possible. We expect to retain the benefits of this competitive process for ratepayers. Therefore, Con Edison, NYSEG, and NYPA should hold their investment costs for these projects to the estimates which they supplied when the project proposals were made, and which are reported supra. The cost recovery sought for each project, as contemplated in this Order, should be limited to actual costs or to the estimates provided here, whichever is lower.

B. EE/DR/CHP Programs

In the 125 MW Revised EE/DR/CHP Program, Con Edison and NYSERDA, in consultation with NYPA, proposed a suite of new EE and DR projects designed to achieve 100 MW of peak demand reduction. They assessed these projects using a Total Resource Cost test, with adjustments, to determine the potential benefits compared to the costs.[42] The results of the test indicated that the benefits were equal to the costs, even assuming IPEC remains in service. The Revised EE/DR/CHP Program further indicated that with IPEC retired, the revised EE and DR programs would be more cost effective.

The costs of customer incentives are expected, on average, to constitute half of the revised EE and DR program costs. Con Edison and NYSERDA propose that a robust and detailed accounting would be maintained. However, the details regarding this accounting were not provided in the Revised EE/DR/CHP Program. Accordingly, we will require Con Edison to consult with NYSERDA and DPS Staff, and to develop detailed accounting procedures, reporting requirements, and an implementation plan, and to file such documents with the Secretary.

DPS Staff conducted a review of the benefit/cost analysis jointly performed by Con Edison and NYSERDA. After modifying the analysis to reflect a better forecast of the wholesale market price of energy, a year-round accounting of costs and benefits (rather than just on summer weekdays), and a more accurate estimate of the length of the programs, DPS Staff estimated that the benefits of the EE and DR programs, which were identified as part of the 125 MW Revised EE/DR/CHP Program, exceeded the costs assuming IPEC remained in service. The net resource cost savings were estimated to be approximately $182

[42] The test was set forth using the following formula:

$$\frac{\text{Benefit}}{\text{Cost}} = \frac{\text{NPV(Energy + LineLoss + Capacity + Environmental + T + D)}}{\text{NPV(UtilityCosts + CustomerCosts + ProgramAdmin)}}$$

We note that the “customer costs” in the above formula are not paid by utility ratepayer funds, but rather by customers’ own funds.

million over 15 years.[43] The estimated net resource cost savings were greater assuming IPEC is retired.

DPS Staff therefore recommends that these EE and DR programs be included in the IPEC Reliability Contingency Plan. We agree with DPS Staff that these EE and DR programs are worthwhile pursuing, given our expectation that the benefits of these projects will exceed the costs. Accordingly, we accept the EE and DR components (totaling 100 MW) of the 125 MW Revised EE/DR/CHP Program, as proposed by Con Edison and NYSERDA.

We disagree with parties that suggest the proposed EE and DR resources should be compared to the cost of the transmission and generation resources that were submitted for consideration as replacement resources for IPEC. Based on the cost effectiveness of the proposed EE and DR programs, such a comparison is unnecessary. These programs are reasonable to pursue, regardless of whether IPEC is retired.

An important consideration for some parties is the extent to which the EE and DR program’s peak demand reduction efforts would be coordinated with NYSERDA and Con Edison’s regular EE programs. We are persuaded that the programs will be appropriately coordinated. Moreover, the proposal has the characteristic that the incentives and program rules of the commercial and industrial programs will be uniform for both the Commission’s Energy Efficiency Portfolio Standard (EEPS) kWh incentives and the incentives for the EE and DR programs which we are considering here. Other elements of these EE and DR programs, such as thermal energy storage and battery arrays, are new programs that will not affect existing EEPS programs.

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[43] The benefits of the EE and DR programs identified in the Revised EE/DR/CHP Program exceeded the costs, even with the environmental components removed. Thus, the $182 million estimate would be even higher if the environmental components were included.

Entergy asserts that reliance on EE is a major deviation from reliability system planning that could threaten system reliability if the energy efficiency program does not achieve its projected gains. We agree that reliance on EE and DR programs is relatively new. Energy efficiency, however, is not so new as to be untested. New York and several other states have accumulated significant experience with EE over the last 20 years. In fact, EE results are routinely used in the NYISO planning process as load modifiers. We are confident that EE is a proven resource that can be relied upon for many purposes, including the one at hand – ensuring reliability in the event IPEC is retired.

Many other details have been suggested by commenters, including combining EE with renewable generation at a customer location, aggregation of small thermal storage projects, and providing extra incentives for “Made in New York” solutions. Our primary goal here, however, is to obtain the peak MW reductions needed by 2016 to help protect against reliability violations which could stem from the retirement of the IPEC. We will therefore accept the proposal, as put forward by Con Edison, NYSERDA, and NYPA, without further imposing specific requirements such as these.

We recognize that the EE and DR programs would be jointly implemented by Con Edison and NYSERDA, and we seek to ensure appropriate coordination between the two entities. The proposal to maintain a “single point of customer entry” should assist in eliminating duplicative procedures and confusion for customers. We anticipate that Con Edison and NYSERDA will develop appropriate agreements to facilitate the provision of any necessary customer information and program funds from Con

Edison to NYSERDA.[44] To the extent such agreements cannot be reached after consultation with DPS Staff, a petition should be filed with the Commission for resolution.

We also find that NYSERDA's Expanded CHP Program should be pursued to obtain 25 MW, which is in addition to the 30 MW that NYSERDA estimates will be achieved in Con Edison's service territory by June 2016 under the CHP Program already approved by the Commission. We recognize that promoting CHP resources has broad and deep support among environmental, governmental, and business interests. We find that committing further funding toward CHP projects will help to advance the Commission's objective of promoting CHP, and to reduce the reliability needs identified in the NYISO's September 18, 2012 RNA. We also concur with the parties that believe that DR and CHP should, in combination, form a substantial component of the resources that are developed as part of the response to the potential retirement of IPEC. To ensure proper accounting and reporting of the CHP aspects of the Revised EE/DR/CHP Program, Con Edison and NYSERDA should develop detailed accounting procedures, reporting requirements and an implementation plan, as we are requiring with respect to the EE and DR programs.

Finally, we acknowledge NYPA's Build Smart NY Program, and will count NYPA's 15 MW target toward the identified reliability needs under the IPEC Reliability Contingency Plan. However, because this program will be funded through NYPA low cost financing that is recovered from the direct program participants, we do not need to approve the program or the

[44] Con Edison shall establish by agreement with NYSERDA, procedures for the transfer of funds to NYSERDA to repay NYSERDA for the costs it incurs in implementing the portion of the Revised EE/DR/CHP Program for which NYSERAD has responsibility. The form of this agreement, and of any amendments to this agreement, shall be filed with the Secretary as a compliance filing.

associated funding. We expect that NYPA will update the Commission in the event that changed circumstances affect the achievement of the target amount within the necessary time frame.

In this Order, we accept the 125 MW EE/DR/CHP program set forth by Con Edison, NYSERDA and NYPA, and we take account of approximately 60 MW of peak demand reduction which these parties expect to achieve from existing programs. We recognize these are modest goals for programs of this type. We believe there continues to be unrecognized, cost-effective opportunities for EE, DR, and CHP programs to meet a greater portion of the reliability needs which the IPEC Reliability Contingency Plan describes. We direct Con Edison, working with DPS Staff, NYPA, and NYSERDA, to intensify its efforts to identify and exploit these additional opportunities, and direct Con Edison to report on these efforts by February 15, 2014.

## Cost Allocation

As noted above, DPS Staff, at our direction, prepared and filed a proposed methodology for allocating and recovering costs associated with the IPEC Reliability Contingency Plan, which was the subject of two technical conferences and various comments. In general, the DPS Staff’s June Straw Proposal recommended that the same cost allocation methodology should be used for each element of the IPEC Reliability Contingency Plan portfolio. In this Order, and as discussed below, we are sensitive to the particular characteristics of the various elements of the portfolio, and we do not conclude that the same cost allocation methodologies should be used for all portfolio elements. Instead, we prefer to tailor the cost allocation solutions in a more granular way so that each specific portfolio element uses the methodology that best suits its particular characteristics.

A. TOTS Projects

In conjunction with their proposal for the TOTS projects, Con Edison and NYPA, along with the other NYTOs, have urged that DPS Staff's June Straw Proposal methodology should not be used to allocate the costs associated with implementing those projects. Instead, Con Edison and NYPA urge that the TOTS costs should be allocated in proportion to the shares already agreed to by the NYTOs in the context of preparing their NY Transco proposal.[45] As noted above, Con Edison, NYPA and the other NY Transco participants have jointly identified 18 transmission projects throughout the State which, if approved, could be undertaken to improve the State's transmission system. The three TOTS projects were among those identified by the proponents of the NY Transco.

In response to the NYTOs' cost allocation proposal, various commenters argued that cost allocation should be based solely upon a reliability beneficiaries pay methodology and should be consistent with the NYISO approach for reliability solutions. Some commenters were specifically critical of the NY Transco approach based upon their belief that the benefits of the three TOTS projects will accrue to Southeastern New York alone, and, at the same time, will bring higher energy costs and emissions to Upstate New York. Commenters also argued that the derivation of the NY Transco method has not been explained, and

[45] The NYTOs have agreed to a NY Transco cost allocation as follows: 5.4% for Central Hudson Gas & Electric Corp. (CHG&E), 38.3% for Con Edison, 16.7% for Long Island Power Authority (LIPA), 10.4% for Niagara Mohawk d.b.a. Nation Grid, 5.8% for New York State Electric & Gas (NYSEG), 3.4% for Orange & Rockland Utilities (O&R), 16.9% for NYPA, and 3.1% for Rochester Gas & Electric Corp. (RG&E). See, NYTO comments, dated July 22, 2013.

that its sponsors have not demonstrated that the method aligns allocated costs with benefits. Further, concerns were raised that the NY Transco method will lead to inconsistencies between TOTS solutions and non-TOTS solutions, thereby resulting in an unlevel playing field and divergence from the NYISO reliability cost allocation approach. Others contended that the NY Transco cost allocation method was previously rejected by the Commission in the April 2013 Order. Finally, some commenters urged that the public policy that is needed to define and sanction the benefits claimed for the TOTS projects has not been developed and that this proceeding was not intended as the forum in which this policy should be developed.

While we understand the commenters' concerns regarding the potential for different cost allocation methods for different solutions, we recognize several factors which weigh in favor of utilizing the proposed NY Transco approach for the three TOTS projects. Specifically, the NY Transco allocation was voluntarily developed and approved by all of the NYTOs. We acknowledge that the NYTOs have achieved a significant milestone in reaching this consensus, as they have solved a problem that can hinder the construction of infrastructure across utility service territories. In this instance, however, that barrier has been surmounted. In addition, based upon the IPEC Reliability Contingency Plan analysis, the three proposed TOTS projects were found to provide net benefits both with and without IPEC in service. We also recognize that the benefits from resource adequacy solutions for the replacement of the IPEC, such as the TOTS, do not accrue solely to downstate consumers. Rather, we agree with the NYTOs that these solutions should also provide some reliability benefits statewide. Based on these factors, we find the proposed allocation of costs and benefits to be reasonable, and support the use of the proposed NY Transco cost allocation methodology.

Finally, we note that the proposed NY Transco approach, which provides that a share of the project costs will be assumed by LIPA and NYPA, achieves a broader distribution of project costs than have been achieveable in the past. In this regard, it is significant that LIPA has already indicated its agreement with the NY Transco approach.[46] For this reason, it appears unlikely that a jurisdictional challenge from LIPA will be made.

B. EE/DR/CHP Programs

DPS Staff's June Straw Proposal was silent on cost allocation for EE, DR, and CHP projects. However, the EE/DR/CHP submissions by Con Edison and NYPA urge that the costs of these programs should be allocated to Con Edison's ratepayers, just as the costs of similar utility EE, DR, or CHP programs have been allocated in the past. No commenters raised specific opposition to Con Edison's proposal. While some commenters favored a single cost allocation approach for all solutions, some favored Con Edison's cost allocation proposal for these programs. NYC stated that cost allocation of EE/DR/CHP projects need not be the same as that afforded to generation and transmission projects. Rather, NYC contends that the "benefits associated with EE/DR/CHP projects are so specific to the utility service territory in which they are located that costs associated with those measures should not be spread to other utilities."[47]

Con Edison will have the ability to target its EE/DR program to help relieve its local distribution system, thereby

[46] NYTO comments on behalf of the NY Transco with respect the IPEC Reliability Contingency Plan, p.9 (filed July 22, 2013)(indicating LIPA's willingness to accept a proposed cost allocation of 16.7%).

[47] Initial comments of NYC at page 7.

deriving specific local benefits. The Revised EE/DR/CHP Program will also provide specific and direct benefits to Con Edison customers in the form of reduced obligations to procure resource capacity.

We agree that, as recommended by Con Edison and supported by NYC and other commenters, the proposed cost allocation treatment, as submitted by Con Edison and NYSERDA, should be adopted. Accordingly, we determine that all of the costs for the Revised EE/DR/CHP Programs implemented by Con Edison and NYSERDA, as discussed herein, should be allocated to Con Edison customers, as proposed in the 125 MW Revised EE/DR/CHP Program. The costs allocated hereunder are referred to as the "Energy Efficiency/Demand Reduction/Combined Heat and Power Program Costs."

## Cost Recovery

### A. TOTS Projects

For TOTS projects, DPS Staff proposed that cost recovery be provided through rate base treatment of the transmission plant in the rate case of the TO building the project. Through that process, the developer TO would place the plant in service and then earn a return on and of its investment. DPS Staff initially proposed that the revenue requirement associated with the plant would be offset by payments from other beneficiary utilities over a term of 15-years (to match the term of the generation Power Purchase Agreement (PPA) in the RFP). Based on verbal comments received during its first technical conference, DPS Staff subsequently proposed that the payments would continue until the original book cost of the project was fully depreciated. DPS Staff further offered that, as an alternative to this proposal, a final “exit payment” could be made by the beneficiary utility to the TO in a manner that does not increase costs to ratepayers.

Once costs are allocated to the other beneficiary utilities, DPS Staff proposed that the allocation of costs to service classes within each utility shall be conducted in the same manner as other transmission capital and operating costs. Once allocated to the service class, DPS Staff proposed that the cost be recovered through class specific volumetric (kWh) and demand (kW) surcharges.

The NYTOs, however, disagree with DPS Staff’s proposed approach and claim that the use of the NYISO tariff to allocate and recover transmission costs is more efficient. The NYTOs argue that the NY Transco charge will be recovered from retail ratepayers in a manner that resembles the current way investor owned NYTOs recover other NYISO charges, such as NYISO Rate Schedule 1 and the NYPA Transmission Adjustment Charge. The NYTOs further contend that their method provides greater certainty and transparency than the June Straw Proposal.

We commend DPS Staff’s significant efforts in developing the June Straw Proposal. However, for the reasons discussed above, and for purposes of cost recovery for the TOTS projects, we support the NYTOs’ proposed cost allocation/recovery approach for these projects. We expect the NYTOs will file an allocation and recovery mechanism which reflects their allocation/recovery approach for review and approval by FERC. We also expect that this application will seek recovery of the initial planning costs, up to $10 million, authorized in the April 2013 Order, and other related costs in developing the IPEC Reliability Contingency Plan.

B. EE/DR/CHP Programs

As discussed above, the 125 MW Revised EE/DR/CHP Program costs will be allocated to Con Edison. Con Edison and

NYSERDA proposed that Con Edison delivery customers pay a surcharge to cover the cost of these projects, after those costs have been incurred, through the Monthly Adjustment Clause (MAC) charge, as is done for its Targeted Demand Side Management Program and other demand response programs, exclusive of NYPA's governmental customers who receive delivery service under the Company's PSC No. 12 - Electricity.[48] Con Edison and NYSERDA estimate that the cost of the Revised EE/DR/CHP Program will be approximately $285 million. While some of these costs, such as portions of the costs associated with measurement and verification and with reporting will be incurred after implementation of the employed program measures, it is reasonable to expect that the majority of the 125 MW Revised EE/DR/CHP Program costs will be incurred from 2014 through 2016. The resulting cost impact in a given year, depending on the timing of the cost incurrence, could be as high as $100 million for Con Edison's delivery customers.

To better match the time when costs of the 125 MW Revised EE/DR/CHP Program are incurred with the time when its benefits will occur, DPS Staff recommends that the costs be amortized over a ten year period. This approach would also mitigate the potential rate increases associated with recovering the costs on an as-incurred basis. We are mindful of the immediate rate impacts associated with the many initiatives that are before us, both in this proceeding and in other on-going proceedings. Accordingly, we authorize Con Edison to amortize the cost of the 125 MW Revised EE/DR/CHP Program over ten years in order to mitigate its immediate rate impacts.

The MAC is used to collect various costs from all of Con Edison's delivery customers. Its use, as proposed here for a similar purpose, is appropriate and therefore adopted. To

[48] See, Revised EE/DR/CHP Program, pp. 20-21.

implement this directive, Con Edison shall file the requisite tariff leaves to allow for cost recovery of the 125 MW Revised EE/DR/CHP Program. In addition, however, we may revisit this cost recovery and amortization period when making final decisions in other proceedings that have an impact on rates, with the goal of minimizing the overall customer impacts.

State Environmental Quality Review Act

Earlier in this proceeding, the Commission considered its obligations under the State Environmental Quality Review Act (SEQRA) and directed DPS Staff to prepare a Generic Environmental Impact Statement (GEIS). Notice of our Determination of Significance was issued on May 21, 2013. DPS Staff subsequently developed a Draft GEIS, which we accepted as complete by Order issued July 18, 2013.[49] As required by SEQRA, a Notice of Completion of the Draft GEIS was published in the Environmental Notice Bulletin (ENB) on July 24, 2013, and comments were accepted until the close of business on August 23, 2013.

Two sets of comments were received through the public comment process. The Final GEIS summarizes all of the substantive comments and reflects revisions made in response to them. Specifically, the following substantive changes were made to the Draft GEIS following the review of the comments:

1. Descriptions of the US Power Generating Company’s generation projects were clarified in Section 2.4.1.3 (Proposed Electricity Generation Projects).

[49] Case 12-E-0503, Generation Retirement Contingency Plans, Order Adopting and Approving Issuance of a Draft Environmental Impact Statement (issued July 18, 2013).

2. Disclosure that the FERC has approved a new local capacity zone covering NYISO Zones G-J was added to Section 4.15.6 (Electric Rates).
3. Discussion of the New York State Energy Plan was added as Section 4.11.4.
4. New subsections were added (Sections 4.11.5 and 5.4.13) to address the impacts of power outages on customers with special needs.
5. A new section in Chapter 6, Cumulative Impacts, was added to specifically address the potential overlap between Energy Highway projects and the IPEC Contingency Plan components.
6. The list of required generalized permits and approvals in Table 7-1 was expanded.

We then determined that the Final GEIS presented a complete and comprehensive assessment of the significant adverse environmental impacts, as well as the benefits, that could arise with the implementation of the IPEC Reliability Contingency Plan; that it conformed to the requirements of SEQRA; and that it adequately responded to all the substantive comments provided on the Draft GEIS. Therefore, on September 19, 2013, we accepted it as the Final GEIS for the proposed adoption of an IPEC Reliability Contingency Plan and directed that the Notice of Completion of the Final GEIS be published in the ENB in accordance with 6 NYCRR Part 617.[50]

The Final GEIS describes the possible environmental impacts associated with the proposed action that includes acceptance of the IPEC Reliability Contingency Plan. The Final GEIS study shows that construction and operation of the projects contemplated in the Contingency Plan may have impacts on environmental resources in New York. The resources that may be

[50] Notice was published in the ENB on September 25, 2013.

affected, depending on the ultimate design of the projects and the construction methods employed, could include land use patterns, water resources, plants and animals, agricultural resources, aesthetic resources, historic and archaeological resources, open space and recreation, critical environmental areas, air quality, transportation, energy, noise and odor, public health, community character, and socioeconomics. The exact extent of these impacts is not quantifiable due to: (1) the complexity of the multiple factors affecting electric system operations in New York; (2) the interaction of New York's power grid with those of other states; (3) the timing of and types of possible market responses; and, (4) the geographically distributed nature of the portfolio of transmission and generation projects included in the IPEC Reliability Contingency Plan, and the likelihood that future regulatory actions will impact the final layout and design of those facilities.

However, the Final GEIS allows us to evaluate the environmental impacts of the proposed action in the context of the conditions that are likely to exist if we did not provide for a Reliability Contingency Plan. By ensuring the reliable delivery of electricity in the event that the IPEC is retired, the IPEC Reliability Contingency Plan minimizes the economic, social, and environmental effects which could result from the loss of that particular source of supply.

We further find that, even if the IPEC remains available, the Final GEIS demonstrates that the likely environmental impacts of implementing the IPEC Reliability Contingency Plan are the typical impacts associated with generation and transmission facilities, and that well-accepted mitigation techniques may be utilized in the design and construction processes to minimize their effects.

We note that these new projects may be subject to site-specific licensing and permitting requirements, and that individualized environmental assessments would be conducted in those other proceedings.[51]

On the basis of the foregoing, and the discussion set forth in the Final GEIS, we make the findings stated above regarding the environmental impacts of the proposed action and certify that:

(1) the requirements of the State Environmental Quality Review Act, as implemented by 6 NYCRR Part 617, have been met;

(2) consistent with social, economic, and other essential considerations, from among the reasonable alternatives available, the action being undertaken is one that avoids or minimizes adverse environmental impacts to the maximum extent practicable, and that adverse environmental impacts will be avoided or minimized to the maximum extent practicable by incorporating as conditions to the decision those mitigative measures that were identified as practicable; and

(3) as applicable to the coastal area, the action being undertaken is consistent with applicable policies set forth in 19 NYCRR §600.5, regarding development, fish and wildlife, agricultural lands, scenic quality, public access, recreation, flooding and erosion hazards, and water resources.

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[51] Specifically, the details of the Ramapo/Rock Tavern project, for which this Commission previously issued an Article VII certificate, will receive scrutiny in DPS Staff’s review of Con Edison’s Environmental Management and Construction Plan (EM&CP). The Marcy/Fraser project will also be evaluated by DPS Staff upon submittal of an EM&CP for the Marcy South elements, and the reconductoring component will be subject to SEQRA review prior to construction. The Staten Island project will also undergo SEQRA review.

Requests for Rehearing

A. March 2013 Order

The March 15 Order accepted the Con Edison/NYPA February Filing as “responsive” to the November 2012 Order and “consistent with Con Edison’s responsibilities to ensure safe and adequate service.”[52] In particular, the Commission accepted Con Edison and NYPA’s determination that the reliability need was 1,350 MW, net of Con Edison’s 100 MW EE and DR program. The Commission therefore approved the proposal, subject to certain modifications, for NYPA to issue an RFP in order to solicit projects for inclusion in the IPEC Reliability Contingency Plan that could assist in meeting this reliability need.

1. IPPNY

On April 5, 2013, IPPNY sought rehearing of the Commission’s March 2013 Order on the basis that the record was deficient and the Commission lacked a rational basis to proceed. IPPNY identified various “deficiencies” in the Con Edison/NYPA February Filing, including 1) the failure to take into account the status of proposed power plants and AC and DC transmission projects; 2) the failure to provide an analysis of the extent, timing, and characteristics of the reliability needs that would arise if IPEC were retired; 3) the failure to quantify the degree to which the TOTS would address the IPEC-related resource adequacy or reactive power impacts; 4) the failure to consider any alternative projects; 5) the failure to demonstrate that the TOTS are narrowly tailored to address IPEC-specific reliability needs; and, 6) the failure to protect New York consumers from unnecessarily incurring substantial costs.

IPPNY further claimed the Commission improperly assigned NYPA the role of initially screening RFP responses for completeness and conformance with RFP requirements. IPPNY

[52] November 2012 Order, p. 3.

contends that NYPA has a conflict of interest, given its involvement in the TOTS projects, which should preclude NYPA from serving any role in the review of the RFP responses.

In addition, IPPNY asserted that the Commission improperly favored the TOTS projects by establishing different cost recovery standards for the TOTS projects compared to the RFP respondents, and failing to recognize potential market-based solutions in accordance with the FERC-approved tariff. IPPNY also maintained that allowing the TOTS projects to provide “good faith estimates,” as a basis for recovering their costs, improperly favored the TOTS over RFP respondents that were required to submit “not-to-exceed-values.”

2. Entergy

On April 11, 2013, Entergy also sought rehearing based on the grounds that the Commission lacked a rational basis to proceed due to deficiencies identified in the February 2013 Contingency Plan Filing. Entergy suggested that the Con Edison/NYPA February Filing must be supplemented before the Commission can proceed, and that the Commission erred in concluding that the reliability deficiency should be “further updated and refined prior to the conclusion of DPS Staff’s evaluation of RFP responses.”[53]

3. Commission Determination

We reject the claims by IPPNY and Entergy that the Commission lacked a rational basis to issue the March 2013 Order, which accepted the Con Edison/NYPA February Filing as responsive to our November 2013 Order, and approved Con Edison and NYPA’s plan to issue an RFP for solutions to meet the reliability planning needs. Neither party disputes the NYISO’s analysis that “identified reliability violations of transmission security and resource adequacy criteria by the summer of 2016 if

[53] March 2013 Order, p. 12.

the IPEC units were retired at the expiration of their current licenses….”[54] The NYISO’s 2012 Reliability Needs Assessment, as updated by the Con Edison/NYPA February Filing, provided a rational basis for the Commission to proceed with the issuance of an RFP. IPPNY’s claimed deficiencies are summarized above and have been addressed in this Order.

With respect to the role of NYPA, we disagree that NYPA was improperly assigned the role of screening timely proposals for “completeness and conformance with the RFP requirements.” As we expected, DPS Staff conducted an independent review of all RFP responses in order to verify and confirm NYPA’s screening results. Because DPS Staff was expected to and, in fact, has provided an independent and unbiased verification of qualifying RFP responses, we reject IPPNY’s argument that NYPA was inappropriately allowed to act in this capacity.

Finally, we find that allowing the TOTS projects to proceed and to recover limited costs in advance of determining a preferred portfolio of resources was not discriminatory, or biased in favor of the TOTS projects. Allowing the TOs to recover some preliminary planning costs for the TOTS appropriately reflects the NYTOs’s statutory responsibilities to ensure safe and adequate service. Accordingly, the petitions for rehearing filed by IPPNY and Entergy with respect to the March 2013 Order are denied.

## B. April 2013 Order

The April 2013 Order approved, subject to conditions, Con Edison, NYSEG, and NYPA’s preliminary planning related to the three TOTS projects. The recovery of preliminary planning costs was approved, up to $10 million, for an initial period until the TOTS projects were analyzed further. Con Edison was

[54] March 2013 Order, p. 7.

also directed to work with NYSERDA and NYPA, and to file a revised plan to secure permanent peak reduction from incremental EE/DR and other resources. The Order also directed DPS Staff to propose a cost allocation and cost recovery mechanism for the Commission's consideration.

1. IPPNY

On May 17, 2013, IPPNY sought rehearing of the Commission's April 2013 Order, which it claimed improperly favored the TOTS projects and discriminated against RFP respondents. IPPNY claimed the Commission improperly authorized preliminary planning activities for the TOTS and the recovery of up to $10 million dollars in related costs. According to IPPNY, these actions provide the TOTS with a "head start" and a significant advantage when compared with RFP respondents. IPPNY further contended that the TOTS should be required to provide firm bids and prevented from recovering cost overruns.

2. Entergy

On May 20, 2013, Entergy filed its request for rehearing, which reiterated many of the same arguments it raised with respect to the March 2013 Order. Entergy continued to assert that the Commission could not rationally undertake any of its actions without curing the alleged "deficiencies" in the record. Entergy suggests that the Commission hold its actions "in abeyance until Con Edison and NYPA have fully identified and quantified the scope and magnitude of Indian Point-based system needs and the PSC has had an adequate opportunity to review those needs."[55]

Asserting that the Commission lacked a rational basis, Entergy also recognized that the 2012 RNA performed by the NYISO "reaffirmed that reactive power needs would also result if

[55] Entergy, p. 16.

Indian Point were required to cease operations."[56] Entergy suggested that the Commission cease reliability planning efforts in this proceeding until additional information is provided, including NYISO analyses "delineating the full nature and extent of Indian Point-related system needs...."[57]

In addition, Entergy submitted that the Commission lacked the statutory authority to allocate costs incurred by Con Edison to other utility customers in the State. Similarly, Entergy submitted that the Commission's authority prevented directing the utilities that were allocated costs from reimbursing NYPA.

3. Commission Determination

In large part, the arguments advanced on rehearing of our April 2013 Order are the same as were brought forward in the petitions for rehearing of the March 2013 Order. As noted above, we have, in considering the Petition for Rehearing for the March 2013 Order, addressed these objections and found they lack merit. We also find that our authority to ensure rates are just and reasonable necessarily entails ensuring costs are allocated appropriately. Accordingly, the petitions for rehearing filed by IPPNY and Entergy with respect to the April 2013 Order are denied.

## CONCLUSION

As stated in previous orders, the potential retirement of the IPEC raises unique and significant reliability issues. These reliability issues, which could threaten the public health, safety, and welfare, are compounded by the inability of existing processes and markets to fashion a timely response. In response to this problem, and, in particular, to fashion an

[56] Entergy, p. 17.

[57] Entergy, p. 25.

appropriate response to the uncertainties associated with the potential retirement of the IPEC as early as December 2015, we sought the development of an IPEC Reliability Contingency Plan.

In this Order, we reviewed the plan developed in response to the Commission’s earlier orders, and find that two components of this plan, i.e., the three Transmission Owners Transmission Solution projects and the 125 MW Revised EE/DR/CHP Program, should be accepted now and move as promptly as possible to implementation. We further find that the IPEC Reliability Contingency Plan, as proposed by Con Edison and NYPA, and as modified in this Order, and which includes these two components properly balances our reliability concerns with the costs to ratepayers, impacts on the environment, and other matters. Accordingly, we conclude that the acceptance of the IPEC Reliability Contingency Plan will support the continued provision of safe and adequate service, and is in the public interest.

Because of uncertainties in the generation market, DPS Staff recommends and we agree that no action should be taken at this time regarding the potential generation solutions identified through the NYPA RFP which was issued in furtherance of the Plan. Con Edison, in consultation with NYPA, should continue to monitor the status of projects which may enter or rejoin the generation market, and to assess whether changed circumstances would justify an expansion of the portfolio approved in this Order for the IPEC Reliability Contingency Plan.

Further, to support the implementation of the IPEC Reliability Contingency Plan, which we are accepting in this Order, this proceeding has described the methodologies that will be used for cost allocation and recovery for projects which are part of the plan. This Order concludes that these methodologies are just and reasonable and may be relied upon as the IPEC Reliability Contingency Plan is implemented.

The Commission orders:

1. The Indian Point Energy Center (IPEC) Reliability Contingency Plan (Plan), as described in the Consolidated Edison Company of New York, Inc. (Con Edison) and New York Power Authority (NYPA) February 1, 2013 Filing (Con Edison/NYPA February Filing), and as further described in the body of this Order, is an appropriate response to the potential reliability needs which could be associated with the retirement of the generation resources at IPEC, and such Plan, as modified through this Order, is accepted.

2. The portfolio currently accepted for the implementation of the IPEC Reliability Contingency Plan shall include two elements, i.e.:

a. The three Transmission Owner Transmission Solutions (TOTS) projects as described in the Con Edison/NYPA February Filing, as updated and discussed in the body of this Order; and

b. The 125 MW Revised Energy Efficiency/Demand Reduction/Combined Heat and Power (EE/DR/CHP) program, as described in the Con Edison/NYPA/New York State Energy Research and Development Authority (NYSERDA) filings, and discussed in the body of this Order.

3. Con Edison and New York State Electric and Gas Corporation (NYSEG) shall, and NYPA and NYSERDA are expected, to use their best efforts to undertake and timely complete their projects being undertaken as part of the IPEC Reliability Contingency Plan, as set forth in the body of this Order.

4. As set forth in the body of this Order, Con Edison and NYSEG, in consultation with NYPA, should proceed as quickly as possible with an application to the Federal Energy Regulatory Commission for approval for the cost allocation and cost recovery for the TOTS projects. Con Edison and NYSEG, in consultation with NYPA, shall supply a report on the progress of this cost allocation and cost recovery application on or before June 30, 2014, and every six months thereafter.

5. Con Edison is directed to file tariff amendments, to be become effective on a temporary basis on or before March 1, 2014, on not less than 30 days notice, as are consistent with the provisions of this Order and necessary to effectuate the recovery of the “Energy Efficiency/Demand Reduction/Combined Heat and Power Program Costs” that have been allocated to Con Edison in this Order. Con Edison shall serve copies of this filing on all parties to this case. Any comments on the filing must be filed within 14 days of service of such filing. The tariff amendments specified in the filing shall not become effective on a permanent basis until approved by the Commission.

6. Con Edison shall consult with NYSERDA and Department of Public Service Staff, and file detailed accounting procedures, reporting requirements, and an implementation plan regarding the Revised Energy Efficiency/Demand Reduction/Combined Heat and Power Programs with the Secretary, as discussed in the body of this Order, within 90 days of this Order. Con Edison shall serve copies of this filing on all parties to this case. Any comments on the filing must be filed within 14 days of service of such filing.

7. Con Edison shall consult with NYSERDA, NYPA, and Department of Public Service Staff, and file a report with the Secretary on the identification of additional cost-effective

opportunities for energy efficiency, demand reduction, and combined heat and power programs, as discussed in the body of this Order, by February 15, 2014.

8. The requirements of Section 66(12)(b) of the Public Service Law as to newspaper publication of the tariff amendments described in Ordering Clause No. 5 are waived.

9. The Secretary may extend the deadlines set forth in this order upon good cause shown, provided the request for such extension is in writing and filed on a timely basis, which should be on at least one day's notice.

10. The developer transmission owners for the TOTS projects identified in this order shall construct and operate the TOTS projects in compliance with any environmental impact mitigation requirements established through the site-specific environmental permitting for such projects.

11. The petitions of Independent Power Producers of New York, Inc. for rehearing are denied.

12. The petitions of Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, Entergy Nuclear Fitzpatrick, LLC, and Entergy Nuclear Operations, Inc. for rehearing are denied.

13. This proceeding is continued.

By the Commission,

(SIGNED) KATHLEEN H. BURGESS
Secretary

SUMMARY OF NOTICES

1. To seek comments in this Case 12-E-0503, the Department issued four notices pursuant to the State Administrative Procedure Act (SAPA). The date of publication for these notices and a summary of the SAPAs are:

1) 2/20/2013 - The Public Service Commission (Commission) is considering portions of a filing made by Consolidated Edison Company of New York, Inc. and the New York Power Authority on February 1, 2013, concerning reliability contingency plans to address the potential retirement of the Indian Point Energy Center (Filing). The Commission is considering whether to adopt, modify, or reject, in whole or in part, the aspects of the Filing identified as items 2(a) through 2(e) on pages 3 to 4, as discussed at those pages and elsewhere in the Filing.

2) 6/5/2013 - The Public Service Commission (Commission) is considering a filing made by the Department of Public Service on June 4, 2013, concerning a proposed method for allocating and recovering the costs associated with the reliability contingency plans to address the potential retirement of the Indian Point Energy Center (Filing). The Department of Public Service also included in the Filing a proposed Reimbursement Agreement to address the costs incurred by the New York Power Authority in connection with the Indian Point Energy Center reliability contingency plans. The Commission is considering whether to adopt, modify, or reject, in whole or in part, the Filing, and may address related matters.

3) 7/3/2013 - The Public Service Commission (Commission) is considering whether to adopt, modify, or reject, in whole or in part, proposed projects for inclusion in reliability contingency plan(s) to address the potential retirement of the Indian Point Energy Center, and may address related matters. The Commission is considering various proposed projects filed in Case 12-E-0503 between February 1, 2013, and June 13, 2013, by Consolidated Edison Company of New York, Inc., New York Power Authority and New York State Electric and Gas Corporation, Poseidon Transmission LLC, West Point Partners, LLC, Iberdrola USA Management Corporation,

Boundless Energy N.E., LLC, CPV Valley, LLC, Cricket Valley Energy Center LLC, GE Energy Financial Services, NRG Energy, Inc., US Power Generating Company, NYC Energy, LLC, Entergy Nuclear Power Marketing (on behalf of Entergy Nuclear Indian Point 2 LLC, Entergy Nuclear Indian Point 3 LLC, and Entergy Nuclear Operations, Inc.), CCI Roseton LLC, Selkirk Cogen Partners, L.P., and AES Energy Storage, LLC.

4) 7/17/2013 - The Public Service Commission (Commission) is considering whether to adopt, modify, or reject, in whole or in part, proposed energy efficiency, demand reduction, and combined heat and power projects filed in Case 12-E-0503 on June 20, 2013, by Consolidated Edison Company of New York, Inc., the New York Power Authority, and the New York State Energy Research and Development Authority (Filing). The Commission may address the June 20, 2013 Filing and related matters in developing reliability contingency plan(s) to address the potential retirement of the Indian Point Energy Center.

2. In addition, the Department issued its own notices for comments and to announce two technical conferences as follows:

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|---|---|---|
| 2/13/2013 | Notices | Generation Retirement Contingency Plans, Notice Soliciting Comments |
| 6/5/2013 | Notices | Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans, Notice Soliciting Comments and of Technical Conference |
| 6/20/2013 | Notices | Generation Retirement Contingency Plans, Notice of Updated Information for Technical Conference |
| 7/2/2013 | Notices | Generation Retirement Contingency Plans, Notice of Second Technical Conference and Revised Comment Schedule |

3. The Department also sought comments in connection with its draft Generic Environmental Impact Statement as follows:

| | | |
|---|---|---|
| 7/18/2013 | Notices | Generation Retirement Contingency Plans, Notice of Completion of Draft Generic Environmental Impact Statement |

SUMMARY OF COMMENTS

African American Environmentalist Association:

The African American Environmentalist Association expresses support for the continued operation of IPEC.

Boilermakers Local Lodge No. 5 (Boilermakers):

The Boilermakers urge the Commission to abandon the development of a contingency plan for the retirement of the IPEC, and instead pursue needed investment in New York's energy infrastructure.

Boundless Energy NE, LLC:

Boundless Energy asserts that the NYTO proposal to cost allocate NYTO projects in the IPEC Contingency Plan in the same way as projects in the AC Transmission Proceeding (Case 12-T-0502) is premature and unfair. It suggests that inappropriate distinctions in cost allocation should not be made between NYTO projects and other transmission developers.

Business Council of New York State:

The Business Council of New York State requests that the Commission abandon its pursuit of an IPEC Reliability Contingency Plan and pursue a more deliberate, discerning approach towards planning for the retirement of New York’s electric generating units.

Business Council of Westchester:

The Business Council of Westchester expresses its opposition to burdening Westchester County and New York City ratepayers with the $811 million cost to develop projects in compliance with the Indian Point contingency plan.

Bronx Chamber of Commerce:

The Bronx Chamber of Commerce maintains that the June Straw Proposal delivers only questionable benefits for the downstate regions, while placing an undue, harmful burden on the local economy.

Brookfield Renewable Energy Group (Brookfield):

Brookfield supports the IPEC contingency planning effort, but maintains that the plan did not provide an opportunity for the market to provide solutions to meet the potential need. Brookfield is concerned that out-of-market approaches to planning have the potential to result in adverse consequences on the markets, impairing investor confidence and significantly increasing the risk profile of merchant generators that are crucial to the functioning of New York's electricity system. Overall, Brookfield believes that the State should endeavor to address identified or contingent needs within market structures wherever possible.

Central Hudson Gas & Electric (Central Hudson):

Central Hudson asks the Commission to consider other benefits in cost allocation besides reliability. It asserts that the use of the new ICAP zone (NCZ) and the indicative Locational Capacity Requirements (LCR) as the basis for the allocation of transmission solutions is a misapplication of the NCZ LCR. Central Hudson maintains the TOTS projects provide the same benefits as AC Transmission and should be cost allocated as per the NY Transco method.

Cogen Technologies Linden Venture, LP (Cogen):

Cogen agrees that it is prudent for the Commission to work with stakeholders to develop a reliability contingency plan to address issues which may arise upon the closure of the IPEC.

Cogen supports the consideration of existing resources in the contingency plan and the availability of natural gas in developing the plan.

Consolidated Edison Company of New York, Inc. (Con Edison):

In its reply to comments on the Con Edison/NYPA February Filing, Con Edison stated that: 1) it appropriately identified the impact from on-going EE and CHP activities, 2) its proposed EE/DR program does target incremental reductions to peak demand, 3) the EE/DR program will allow a clear market signal to develop that encourages peak demand reduction, 4) the proposed incentive structure is complementary to existing utility and NYSERDA EEPS programs, 5) it has evaluated likely opportunities where the market can quickly deliver peak demand reductions, 6) program costs will be collected in arrears, and will cost between $150 to $300 million. Con Edison also provided additional details regarding its proposed Cost/Benefit test.

Consolidated Edison Solutions, Inc.:

Con Edison Solutions notes that the collection of transmission costs from all Load Serving Entities through a NYISO charge would be a departure from the historical practice of having the individual transmission owner recover its transmission costs as part of its delivery service charge from all its customers, regardless of whether such customers are purchasing their electricity from the utility or a competitive supplier such as Con Edison Solutions. In addition, transmission costs are not something that competitive suppliers can hedge or readily predict. Therefore, to the extent that the Commission approves the Filing, Con Edison Solutions requests that the Commission direct the various utilities participating in these projects to work with the NYISO to provide periodic estimates of the anticipated revenue requirements and resulting transmission rates that LSEs would be charged and that customers can expect to pay.

Consumer Power Advocates (CPA):

CPA argues for a balanced approach to address any reliability needs including a strong EE/DR program, with "market pricing mechanisms for EE/DR as the best way to insure balance between demand side and supply side solutions." CPA also argues that Distributed Generation and Combined Heat and Power systems also be included in the EE/DR program.

Cricket Valley Energy Center LLC (Cricket Valley):

Cricket Valley generally supports the Con Edison/NYPA Contingency Plan, but requests revisions to the proposed in-service date making it farther out in time. Cricket Valley also suggests the Plan is biased toward the TOTS and EE/DR programs, and seeks to have generation projects compete on an equal basis.

Empire Generating Co., LLC, et al.[58]:

The New York Generators argue that FERC has exclusive jurisdiction over the interstate transmission projects and wholesale generation projects proposed in this proceeding, thereby precluding the Commission’s jurisdiction. The Straw Proposal, according to the New York Generators threatens to preclude or interfere with NYISO operations and planning process. They maintain that the Commission’s jurisdiction over cost allocation has not been established.

[58] Empire Generating Co, LLC, TC Ravenswood LLC, US Power Generating Company (parent company of Astoria Generating Company, L.P), PSEG Power New York LLC and PSEG Energy Resources and Trade LLC submitting jointly as the “New York Generators”.

Entergy Nuclear Indian Point 2, LLC, et al. (Entergy):

Entergy argues that the Con Edison/NYPA February Filing does not indicate the full nature of the reliability impacts that would be caused by an IPEC shutdown. Entergy notes that the NYISO's 2012 RNA indicates that there would be both resource adequacy and reactive power implications if Indian Point was required to cease operations, and points out that the Filing only quantifies the resource adequacy related needs.[59]

Entergy strongly opposes adoption of the IPEC Reliability Contingency Plan. Entergy first argues that the Plan has failed to provide all the information identified in the Commission's April 19, 2013 Order, and thus the Commission lacks basis for approving the plan. Entergy argues that insufficient system planning and analysis has been completed and in particular there is a lack of information about the extent, timing, and characteristics of system needs related to a possible IPEC closure. Entergy points out that IPEC retirement needs, as identified in the NYISO's 2012 Reliability Needs Assessment, include resource adequacy needs, transmission security needs and reactive power considerations. It argues the Con Edison/NYPA February Filing failed to consider transmission security needs and reactive power considerations. Further, Entergy argues the Commission's March 2013 Order (approving the RFP process) and April 19, 2013 Order (advancing transmission and EE/DR/CHP projects) were both issued irrespective of these non-resource considerations. Entergy also points out that although DPS staff confirmed at the July 15, 2013 Technical Conference that transmission security needs have been completed, no analyses were provided, including a quantification of the estimated level of transmission security violations that would occur with an IPEC retirement. Entergy points out that resource adequacy

[59] Entergy comments, February 22, 2013, p. 11.

estimates provided by DPS Staff at the Technical Conference differed from the earlier Joint Plan calculation, providing further support, Entergy argues, that the "core information" identified in the Commission's November 2012 Order (i.e. "the full extent, timing and characteristics of system needs") is lacking. Entergy concludes this point by arguing that absent this information, adoption of the EE/DR/CHP program would be arbitrary and capricious.

Entergy argues there is a lack of information regarding whether the Revised EE/DR/CHP Program, together with the TOTS projects, addresses IPEC-specific system needs. Entergy's view is that the TOTS projects and EE/DR/CHP plan do not address the full scope of the system resource adequacy, transmission security, and reactive power considerations. Entergy opines that there has been a lack of portfolio-based analysis and that the TOTS projects and EE/DR/CHP plans, as well as the earlier plan, have failed to properly assess other alternatives and whether such alternatives could be "implemented at a later time and/or at a lower cost to better protect New York consumers." Entergy concludes by reiterating its view that the Commission lacks a rational basis to approve the EE/DR/CHP plan absent a full assessment of system needs, the quantification of the proposed solutions towards the needs and an assessment of alternatives, including timing and costs.

Entergy also suggests that even if the record was sufficient, the Revised EE/DR/CHP Program requires changes. Entergy argues that the EE/DR/CHP plan should be properly evaluated within a broader competitive process. Entergy argues the EE/DR/CHP plan was erroneously separated from the RFP process required from the Commission's November 2012 Order. While the earlier Con Edison/NYPA February Filing proposed that the TOTS Projects would subsequently be compared against RFP procured projects, Entergy argues that there have not been any provisions for the EE/DR/CHP plan to be evaluated against other options. Entergy recommends that the EE/DR/CHP plan also be assessed using the “Comparative Evaluation Process” for evaluating the TOTS Projects and RFP Projects against each other.

Entergy argues that the EE/DR/CHP plan must not supplant the EEPS Program. Entergy argues that further review is required to ensure the EE/DR/CHP plan would foster, and not supplant, existing EEPS programs and why those EEPS programs have not focused on the proposed incremental savings.

Entergy argues the projected schedule of MW reductions should be further reviewed. Entergy points out that the originally filed Joint Plan presented, in Entergy’s opinion, an overly aggressive MW reduction schedule that projects the 100 MW reduction from EE/DR/CHP to be accomplished by the end of 2015. In particular, Entergy points out that the Joint Plan plans to achieve 34% of the MW savings during the first 21 months of the program with the remaining balance to be achieved during the 12 months of calendar year 2015. Entergy echoes the initial comments of New York City which opines that trends in efficient lighting programs suggest most efficiency gains from lighting come early in a program and then are increasingly difficult to attain. This, in Entergy’s view, conflicts with the projections of the Joint Plan, and Entergy recommends that the Commission, therefore, carefully scrutinize the reasonableness of the proposed MW attainment schedule.

Entergy requests that the Commission: (1) reject Section 2(e) of the Joint Plan, which finds the TOTs project meet public policy requirements, because neither the November 2012 Order, which defines the scope of this proceeding nor the EHI Task Force Blueprint, establish "public policy requirements" as defined by the NYISO in its October Compliance Filing even if the FERC ultimately accepted the NYISO's expansive definition in this regard; (2) direct Con Edison (with NYPA, to the extent deemed necessary) to expeditiously supplement the Joint Plan to provide information: (i) identifying in detail the full scope and nature of the reliability needs that would be triggered if the Indian Point facilities were required to cease operations; (ii) quantifying the degree to which each of its proposed solutions addresses each identified need; and (iii) identifying the timing and costs of other alternatives that also are viable options to address each identified need; and (3) defer any action on the Notice as it pertains to Sections2(a) through (d) of the Joint Plan until Con Edison supplements the Joint Plan.

Entergy argues that FERC has exclusive jurisdiction over rates, terms, and conditions of transmission service and wholesale generation service, and State law provides no basis for the Commission to implement the June Straw Proposal. It maintains two flawed assumptions exist in the Straw Proposal: (1) markets forces will fail to provide a solution if IPEC ceases operations; and (2) the NYISO’s reliability planning process will fail to address the problem. Entergy suggests the NYISO gap solutions are intended to solve this problem. It suggests there are no current reliability needs, and no proof that the IPEC can’t be relicensed.

Environmental Defense Fund (EDF):

EDF commends the Commission for its vision in recognizing that energy efficiency, distributed renewable generation, demand response, and combined heat-and-power represent resources that can play a critical role in meeting system needs.

Hudson Valley Gateway Chamber of Commerce:

The Hudson Valley Gateway Chamber of Commerce raises concerns with the financial impacts of the June Straw Proposal.

H.Q. Energy Services (HQ):

HQ urges the Commission to adopt a RFP process that allows developers to propose in-service dates for their respective projects later than June 2016. Allowing for alternative in-service dates, HQ asserts, will encourage more developers to participate in the RFP process, thereby driving competition, lowering project costs and increasing options to alleviate reliability concerns.

Ian Ramcharitar:

Opposes the development of the IPEC Reliability Contingency Plan because it would add a surcharge to the existing rates, which he maintains are already too high.

Ice Energy Holdings Inc. (Ice Energy):

Ice Energy, which manufactures and develops thermal (ice) storage systems, strongly supports the Contingency Plan and the inclusion of thermal energy storage systems in the Plan. Ice Energy recommends the Plan be further modified as follows; Ice Energy argues that enhanced payments be added for projects or technologies that combine energy efficiency or demand response with customer-side distributed renewable energy resources, such as photovoltaic energy. Ice Energy takes exception to footnote 8 on page 9 of the Plan where Con Edison and NYSERDA state that further discussion is needed before Renewable Portfolio Standard-eligible renewables can be included. Ice Energy argues that innovation now allow multiple technologies to be deployed in a single project and that such combined systems should be "entitled to enhanced payments to provide appropriate incentives for such clean energy transition."

Ice Energy recommends that the aggregation of smaller projects into one or more larger projects be explicitly allowed. Ice Energy notes that the Plan language may be interpreted as implicitly allowing this but they recommend that aggregation be explicitly added to the Plan. They cite the language on page 4 of the Plan, which states the incentives will include a bonus for “large projects and project aggregations by large customers”. Ice Energy also notes the statement on page 5 of the Plan which indicates Con Edison will focus its recruitment on large commercial and industrial customers. Ice Energy comments that program objectives can also be accomplished by focusing on many smaller commercial and industrial customers and aggregating small projects into larger projects that can be monitored and controlled as one project. Ice Energy states, for example, that the definition of a large project could be one customer in excess of 1MW or more peak day demand, or could alternatively be defined as an aggregation of smaller customers into 1MW or more of peak day demand. Ice Energy further states that incentives should be payable to either an eligible electric customer paying into the IPEC Reliability Surcharge or to a project developer that aggregates multiple host sites in which all of the electric customers within the aggregation would otherwise qualify for individual payments.

Ice Energy recommends extra benefits for made in New York Solutions. Ice Energy argues that solutions manufactured in New York State provide “substantial additional benefits” that merit enhanced benefit premium payments. Procuring locally sourced equipment provides benefits, in Ice Energy’s opinion, of enhancing clean energy innovation, reducing greenhouse gases used in out of state shipping, and enhancing the states struggling tax base.

Ice Energy argues that where a technology or project provides more benefits to Con Edison than to a distributed host customer, Con Edison should pay more than the proposed 50-50 cost share allocation. Ice Energy takes exception to the Plan’s “implicit” assumption, in its opinion, that customer benefits from a project will, at all times, be equal to or greater than Con Edison’s benefits. This, in Ice Energy’s view, is the basis for the footnote 6 on page 8 which states “cost share for participants represents approximately half of total project costs.” Ice Energy posits that this implicit assumption is not always true and cites an example where a customer installs a thermal storage system which allows for more efficient air conditioning operation. Ice Energy argues that in cases like these the energy savings and lower bill benefits to the customer can often be far outweighed by the benefit to the utility in terms of peak demand reduction, reduced need for transmission and distribution infrastructure, and environmental benefits from less fossil fuel consumption for required peaking generation. Ice Energy concludes that Con Edison would be a “free rider” in these cases and that the proposed 50/50 sharing in these cases would lead to the project being non-cost-effective from the customer side, potentially killing such projects. Ice Energy recommends, therefore, that incentive payments are allowed to be graduated to increase customer payments in cases where the utility benefits more than the customer.

Ice Energy further argues that renewable energy should be included. Ice Energy reiterates that the peak day demand reduction benefits of renewable energy technology is well proven and should be included in the Plan, and that this should be done without the need for exhaustive study or further delay.

<u>Independent Power Producers of New York, Inc. (IPPNY)</u>:

IPPNY, similar to Entergy, also argues that the Con Edison/NYPA February Filing fails to indicate the full nature of the reliability impacts that would be caused by an IPEC shutdown. IPPNY further states that Con Edison’s proposal does not give market-based solutions an opportunity to respond to the IPEC reliability deficiency need. IPPNY contends that the IPEC

Contingency Plan harms the competitive market and it is substantively deficient.

Jan Mayer:

Opposes the development of the IPEC Reliability Contingency Plan, which she contends will increase rates and have no benefits.

Long Island Power Authority (LIPA):

LIPA notes the Commission’s limited jurisdiction over LIPA. LIPA asserts DPS Staff’s Straw Proposal has various differences from the NYISO’s reliability cost allocation approach and does not address the beneficiaries pay principle.

Mary Ellen Furlong:

Ms. Furlong questions the timing of the IPEC Reliability Contingency Plan, which she characterizes as an attempt to “sneak” a ratepayer fee.

Matthew Fiorillo:

Mr. Fiorillo opposes the IPEC Reliability Contingency Plan and the June Straw Proposal as an unnecessary increase in electric rates.

Multiple Intervenors (MI):

MI argues that the Con Edison/NYPA February Filing fails to include an analysis, for planning purposes, of the extent, timing, and characteristics of the reliability needs that would arise if Indian Point Units 2 and 3 were retired, as required by the November 2012 Order. MI requests that the Commission reject the contingency plan submitted by Con Edison and NYPA as deficient. Additionally, if and when cost allocation issues are ripe for resolution in this proceeding, MI asks the Commission to adhere to the same “beneficiaries pay” principles that it has enumerated and followed very recently when confronted with the exact same issue (i.e., the incurrence of costs to solve a potential reliability problem created by the proposed closure of a generation facility).

MI focused its reply comments on Staff's June Straw Proposal, arguing first that the Commission should refrain from the unnecessary imposition of exorbitant costs on retail electricity customers, especially based on the incomplete record in this proceeding. MI argues that the purported contributions of individual projects such as the TOTS, and presumably (but not explicitly stated) the energy efficiency plan, are "not clear and unproven." Secondly, MI argues that the NYTOs' arguments opposing the Commission's prior approval of "a reliability beneficiaries pay" cost allocation methodology should be rejected. In a point related to this, MI states the IPEC reliability proceeding falls short of the requirements of FERC Order No. 1000 on Transmission Planning and Cost Allocation, which directs that transmission planning and cost allocation initiatives be "broadly considered through legislative process or a broadly considered comprehensive regulated process." MI concludes that the Commission's possible approval of the TOTS projects or EE/DR/CHP plan is not being completed in response to a broad considered public process, but rather is being contemplated by a narrower desire to maintain reliability in the face of the possible closure of IPEC.

MI argues that the Commission should not approve the TOTS projects, but instead evaluate them thoroughly along with any RFP submitted projects. MI also continues to argue for the "beneficiaries pay" allocation policy. It also reiterates its initial comments that there was "inadequate justification for the proposed, substantial expenditures on energy efficiency ("EE") and demand response ("DR")."

MI argues against the NY Transco approach on the basis that: (a) the NY Transco concept has yet to be justified and does not yet exist; (b) it is unclear if NYPA or LIPA can participate in the NY Transco; (c) contrary to statements that NY Transco will be a public/private partnership, it appears to exclude any material private investment, thereby being funded primarily through ratepayers; (d) NY Transco has not been shown to be in the public interest; and, (e) the Commission has not approved the NY Transco concept. Therefore, MI posits that no basis exists to adopt the NY Transco cost allocation method.

MI argues the NY Transco cost allocation methodology in inconsistent with the Commission's prior ruling that allocation should be based upon reliability beneficiaries pay. The NY Transco cost allocation method, according to MI, is highly inequitable to Upstate NY customers as they are not beneficiaries of the IPEC Contingency Plan. It notes the Commission has allocated costs of Upstate NY generator closings to Upstate NY customers without considering allocating any costs to Downstate. It also suggests that benefits, other than reliability, are irrelevant to cost allocation given that the IPEC Contingency Plan was undertaken to address reliability concerns, and the Commission ruled that costs in this proceeding should be based on reliability beneficiaries pay. MI argues this proceeding is specifically limited to the potential closing of the IPEC, and as such is not invoking any statewide public policy, thereby making the argument that TOTS projects provide public policy benefits specious when no federal or State law or regulation or order has defined or sanctioned that public policy.

Municipal Electric Utilities Association (MEUA):

MEUA argues that the Commission should retain a beneficiaries pay model, such as the DPS June Straw Proposal. MEUA contends the NY Transco allocation directly violates the

April 2013 Order, which indicated that cost allocation should adhere to a beneficiaries pay principle. It also argues that NY Transco claims of benefits are unsupported on the record. Derivation of the NY Transco cost allocation method has not been explained. Further, MEUA asserts that the NYTOs have not demonstrated that the NY Transco cost allocation satisfies FERC's cost allocation requirements.

Natural Resource Defense Council and Pace Energy and Climate Center (NRDC):

NRDC asserts that this proceeding presents an opportunity for the State to set an example for the nation on how to responsibly confront the potential retirement of baseload generation in a manner that maintains reliability through an innovative portfolio of diverse resources—including a robust suite of investments in targeted energy efficiency, renewables, clean distributed generation, such as CHP, and demand response. NRDC is concerned that the Con Edison/NYPA February Filing relies primarily on the 20th century model of large central generation and upgrades to transmission infrastructure. NRDC argues that while these conventional resources will likely be a component of the final contingency plan, they should only be considered after all cost-effective energy efficiency, distributed and other renewable generation, CHP and demand response is achieved.

New York Affordable Reliable Electricity Alliance:

The New York Affordable Reliable Electricity Alliance opposes the June Straw Proposal cost allocation. It maintains that the continued operation of the IPEC makes good sense for the State's energy supply and economy.

New York Battery and Energy Storage Technology Consortium, Inc. (NY-BEST):

NY-BEST comments that distributed energy storage systems should be part of Con Ed's planned 100MW of Energy Efficiency/Demand Reduction/CHP. NY-BEST opines that distributed energy storage solutions are becoming commercially available, and offer the potential benefits of better balancing of transmission and distribution resources and deeper penetration of renewable resources. NY-BEST also points out that the generally smaller size of distributed storage systems compared to traditional generation and transmission and distribution solutions, and the ability to aggregate storage systems, offer advantages of easier and quicker deployment that can “substantially contribute to reducing demand reduction by 100 MW by the summer of 2015 in the Con Edison territory."

New York City Hispanic Chamber of Commerce, Inc.:

The NYC Hispanic Chamber of Commerce expresses deep concern and opposition with the proposal to require Con Edison to spend nearly $1 billion of ratepayer money to find a replacement for the IPEC.

New York City Office of Long-Term Planning and Sustainability (NYC):

NYC argues that the Con Edison/NYPA February Filing does not indicate the full nature of the reliability impacts that would be caused by an IPEC shutdown. NYC also comments on Con Edison’s filing pertaining to its analysis of the reliability needs that would arise from an IPEC shutdown stating that the “discussion is provided but limited to the reference to the NYISO 2012 Reliability Needs Assessment.”[60] NYC claims that Con Edison’s Plan does not include an “identification and assessment

[60] NYC comments, February 22, 2013, p. 13.

of the generation, transmission, and other resources."[61] NYC also contends that there is no need for the Commission to burden the State's ratepayers with hundreds of millions, or billions, of dollars of unnecessary costs on generation and transmission facilities that will not be needed in 2016.

With respect to EE/DR/CHP, NYC argues that the Commission should not apply the cost allocation methodology set forth in Staff's Straw Proposal to EE/DR/CHP projects. The City argues that EE/DR/CHP benefits projects are specific to the utility service territory in which they are located and that costs associated with those measures should not be spread to other utilities.

NYC argues that the Commission should not approve the Con Edison/NYPA February Filing. Instead, NYC recommends the following changes to the EE/DR program proposed in the contingency plan: 1) "before authorizing any expenditure of ratepayer funds, the PSC should direct Con Edison to engage in the preliminary fact-finding and analysis necessary to prove both the reasonableness of its proposals and that the load/demand reductions can actually be achieved;" 2) "if energy efficiency and demand response are to be part of the replacement for the output of IPEC, the most logical and appropriate approach would be to expand or increase funding for the [Energy Efficiency Portfolio Standard] programs, and to target such programs to affected downstate areas;" 3) "the PSC should not allow Con Edison to spend more on energy efficiency or other load reductions than it would cost to replace the capacity of IPEC;" 4) the "PSC [should] treat the [EE/DR] expense as a shareholder-provided capital investment for which its shareholders would receive the same rate of return applicable to its actual capital investments; 5) Should the PSC decide that

[61] MI comments, February 22, 2013, p. 6; NYC comments, February 22, 2013, p. 13.

Con Edison should proceed with the EE/DR program, "the City recommends that the Company’s effort be focused on supporting and incentivizing distributed generation (“DG”) projects throughout the City that could be completed by 2016 and that would, with greater likelihood, result in large-scale peak load reductions;" and, 6) Con Ed should continue to use the TRC test. In the City's words, "Given the higher costs of the proposed program, the use of less demanding standards to measure cost-effectiveness is inappropriate and should not be adopted."

NYC argues that FERC has exclusive jurisdiction over interstate transmission service, including the TOTS. It also asserts that no studies have been performed to indicate Zones G-J are the only beneficiaries of the IPEC Reliability Contingency Plan. It notes the DPS Staff June Straw Proposal does not allocate costs to municipalities or cooperatives. However, NYC suggests that the EE/DR/CHP programs are locational specific, are moving separately in this proceeding and do not compete with generation or transmission, and is therefore fair to allocate the costs of EE/DR/CHP to Con Edison’s service territory.

NYC also argues the Commission lacks jurisdiction over NYPA to recover NYPA costs incurred. NYC suggests that NYPA can procure new capacity on behalf of NYC only with NYC’s express consent.

New York Energy Consumers Council, Inc.:

The New York Energy Consumers Council hopes the Commission will act responsibly and refuse to order the expenditure of any unnecessary ratepayer funds while the closure of Indian Point remains inconclusive.

New York State Assemblyman Alfred Graf:

Assemblyman Graf is concerned about the potential cost-shifting to the already beleaguered ratepayers on Long Island as the New York Power Authority, with Con Edison move forward with

New York State Assemblyman McDonough:

Assemblyman McDonough expresses strong concerns with potential cost-shifting to Long Island.

New York State Assemblyman Joseph D. Morelle:

Assemblyman Morelle is concerned with the pace of this proceeding, and that ratepayers in one region of the State may wind up subsidizing ratepayers in another region of the State. He is also concerned about the effects of a rate increase on business, families, and the economy.

New York State Assemblyman William A. Barclay:

Assemblyman Barclay conveys his strong concerns regarding the implementation of the Indian Point Contingency Plan and the cost that such a plan will have on New York ratepayers.

New York State Assemblyman Andrew R. Garbarino:

Assemblyman Garbarino has concerns with potential cost-shifting to Long Island ratepayers as part of the IPEC Reliability Contingency Plan.

New York State Department of Environmental Conservation (DEC):

DEC requests that the Commission give priority to environmentally beneficial projects such as renewable energy and repowering existing generation facilities.  DEC also seeks to ensure adequate consideration of environmental factors.

New York State Energy Research and Development Authority (NYSERDA):

NYSERDA comments on the Con Edison/NYPA February Filing state that the proposed EE and DR programs include technology options and customer eligibility parameters that are inappropriately narrow while the proposed budget and ratepayer collections appear inappropriately expansive. While NYSERDA believes the 100 MW target is reasonable, it suggests options and opportunities to deliver 100 MW of EE and Load Management (LM) load reduction.

New York State Senator David Carlucci:

Senator Carlucci asserts that due to the uncertainty over the continued operation of Indian Point Energy Center, a comprehensive plan must be developed in the event the facility is retired.

New York State Senator George D. Maziarz:

Senator Maziarz expresses concern regarding the potential cost implications to ratepayer from the implementation of the IPEC Reliability Contingency Plan. In his view, these costs should not be allocated to Upstate ratepayers but should be focused on consumers in Westchester and New York City. He expresses additional concerns about the possibility that assets or resources of NYPA, which are created through the NYPA hydroelectric facilities in Western New York, will be directed to IPEC Reliability Contingency Plan investments, which are located in southeastern New York and which are unlikely to provide benefits to Western New York customers. Finally, Senator Maziarz objects to the magnitude of the costs of the facilities which could be a part of the Plan's portfolio, and especially where the recovery of some or all of these costs will require rate increases for NYPA customers. Senator Maziarz concludes by recommending that the investments approved in the Plan should be directed toward the construction of new transmission facilities so that power can more easily flow from Upstate and Western New York power plants to New York City customers.

New York State Senator Kevin S. Parker:

Senator Parker raises concerns regarding the proposal to require Con Edison ratepayers (along with other New York distribution utilities), to spend nearly $1 billion to find a replacement for the IPEC.

New York State Senator Mark Grisanti:

Senator Grisanti urges the Commission to consider the cost implications to the ratepayers of Upstate New York associated with the development and implementation of the IPEC Reliability Contingency Plan.

New York State Senator Ted O'Brien:

Senator O'Brien urges the Commission to consider the cost implications to Upstate New York ratepayers.

New York State Senator Timothy M. Kennedy:

Senator Kennedy argues that the contingency plan developed by Con Edison and the NYPA will burden ratepayers in Upstate New York with subsidizing projects that will solely benefit downstate customers.

New York Transmission Owners (on behalf of NY Transco):

The NYTOs argue that all NY Transco projects (with TOTS being a part) provide significant statewide benefits. The NYTOs maintain there are various benefits in the aggregate of all NY Transco projects in terms of added jobs, tax revenues, economic growth, emissions, energy market efficiency and reliability. The NY Transco adjusted load ratio share cost allocation, they maintain, accounts for all benefits that may accrue upstate and downstate. The adjusted load ratio share Transco cost allocation assumes 75% of befits accrue Downstate versus 60% for a straight load ratio share. The NYTOs argue that the same cost allocation for transmission, generation, and DR does not accommodate different benefits because each (or at least transmission versus generation/DR) impact the system in different ways.

The NYTOs urge the Commission to endorse the NY Transco cost recovery proposal. NY Transco cost recovery method via the NYISO Tariff will apply to all loads and will obviate the need for contracts; and therefore will be more efficient and less problematic administratively than the DPS Straw Proposal to recover transmission costs. Irrespective of the methods chosen, the NYTOs request that the Commission ensure full cost recovery.

NRG Energy, Inc. (NRG):

NRG states in its comments that it "understands that the New York Independent System Operator's 2012 Reliability Needs Assessment concluded that violations of transmission security and resource adequacy criteria would occur in 2016 if the 2,000 MW Indian Point Plant were to be retired at the end of 2015." NRG further notes that there would be "dramatic and immediate reliability impacts."[62]

Nucor Steel Auburn, Inc.:

Nucor Steel supports DPS Staff's cost recovery Straw Proposal. Nucor Steel agrees with a "beneficiaries pay" approach, and an allocation based upon peak coincident demand

[62] NRG comments, February 22, 2013, (no pages numbers on document but would be 2-3 if numbered).

and expanding it to non-transmission solutions (as opposed to the NYTO proposal which only applies to TOTS). Nucor Steel indicates there is a need to recognize and reconcile overlap between this proceeding and the AC Transmission upgrades case (12-T-0502) by affirming that reliability takes precedence for cost allocation. It also suggests that the exit payment mentioned in June Straw Proposal needs more detail.

Paul Heagerty:

Mr. Heagerty maintains that the possible addition of more electric generating plants in New York State could increase his power bill, while the IPEC already produces safe, reliable and clean energy already.

Pure Energy Infrastructure, LLC (Pure Energy):

Pure Energy proffers that the proposals for inclusion in the IPEC Reliability Contingency Plan need to be carefully managed and evaluated to ensure that low-cost, competitive and reliable transmission/generation solutions result. Pure Energy supports the use of the total resource cost test in conducting this evaluation. Pure Energy also advises that multi-unit, distributed generation resources offer unique reliability benefits, which the Commission should consider.

Queens Chamber of Commerce:

The Queens Chamber of Commerce expresses concern about the cost of the June Straw Proposal.

Retail Energy Supply Association (RESA):

RESA contends that this entire proceeding and the development and implementation of various transmission and generation reliability projects rest on the assumption and presumption that the Indian Point generating facility will fail to be relicensed and will be taken out of operation. Under these circumstances, RESA argues it would be prudent for the Commission to move in a cautious and deliberate manner that is reflective of the provisional nature of the entire need for these reliability projects. RESA supports the cost recovery methodologies presented in the DPS Staff June Straw Proposal. According to RESA, including cost recovery in delivery rates is consistent with previous Commission cost recovery approaches such as Renewable Portfolio Standards and Energy Efficiency Portfolio Standards and is administratively simpler/more efficient, as opposed to the approach advocated by Con Edison, et al.

Richard Roberts:

Mr. Roberts opposes the IPEC Reliability Contingency Plan, which he characterizes as a “dangerous and unnecessary path that would exacerbate the climate and air pollution challenges we already face, while at the same time costing us jobs and hurting New York's economy.”

Robert Licata:

Opposes the development of the IPEC Reliability Contingency Plan because it would increase rates, which he maintains are already too high, while the IPEC provides an available source of energy.

Rockland Business Association:

The Rockland Business Association is concerned about the cost of the June Straw Proposal. It argues that there is a fundamental need for the IPEC's continued operation and the multitude of benefits it provides.

Sierra Club:

Sierra Club endorses Con Edison’s aggressive approach to energy efficiency and demand resources. It urges the Commission to require a significantly robust approach to distributed renewable generation to fully capitalize on this useful and cost-effective resource. Sierra Club also encourages the Commission to ensure that the RFP is structured in a way that it will not result in a significant net increase in New York’s greenhouse gas emissions, by carving out a significant role for renewable energy.

Steamfitters Local Union 638:

The Union is dismayed that, with major warning signs about climate change, the Commission would be spending so much time and taxpayer dollars on efforts to close Indian Point -a significant source of carbon-free electricity.

Thomas McCaffrey, Russell Warren, Phil Quesnel, Stephen Juravich, John Kaczor, Christine Rorrenberk, Anthony DeDonato, Neil Burke, Thomas Pulcher, Dan Johnson, Mario Digenova, Joseph Bubel, Michael Delvin, Richard Drake, J.A. Tonkin, Maureen Bubel, Joe Pechacek, Debra Caltabiano, Edward DeGasperis, Roy Spangenberger, Thomas Opet, Lou Merlino, Rich Lamb, Stanhope Waterfield, Mike Harris, James Timone, Daniel Cooke, Leland Cerra, Joseph Rutz, Robert Herrmann, Harry Primrose, Tom Phillips, Cathy Izyk, Adam Kaczmarek, David Buyes, Benjamin Lawrence, Cheryl Croulet, Donald Croulet, Daniel Cooke, Theresa Motko, Tony Iraola, Brett Kenner, Peter Gunsch, Kelly Smith, Arun Thomas, Paul Platt, Kou John Hong, Deborah Fields, James Thompson, Robert Altadonna, Kai Lo, E. Dean Hewitt, Robert Heath, Dennis Skiffington, Ray Fucheck, et al.

These individuals urge the commission to abandon this proceeding as this process is not in the best interest of all New Yorkers. The potential costs in electric rates to plan for the potential closure of a facility that is intent on staying open for business is an inexcusable waste of our limited taxpayer dollars.

Town of Huntington, New York:

The Town supports the repowering of the existing Northport Power Station, which it argues should be included in the IPEC Reliability Contingency Plan.

Town of Putnam Valley, New York:

The Town requests that the Commission withdraw the contingency plan and the June Straw Proposal for cost recovery. It maintains that the consequences of this plan will worsen the current fiscal stress that local governments currently face, and transfer unnecessary cost burdens to ratepayers in the region.

US Power Generating Company, LLC (USPowerGen):

USPowerGen identifies several technical inaccuracies in the descriptions of the USPowerGen projects discussed in the Indian Point Contingency Plan, Draft Generic Environmental Impact Statement July 2013.

Utility Workers Union of America Local 1-2:

The Utility Workers Union of America Local 1-2 supports the continued operation of the IPEC.

Westchester County Association:

The Westchester County Association expresses its deep concern with the June Straw Proposal, and that ratepayers will be saddled with $811 million in added costs for projects that will likely be deemed unnecessary, especially if the plan was solely developed for the purpose of replacing the power from Indian Point.

West Point Partners, LLC (West Point):

West Point maintains that several modifications to the plan proposed in the Con Edison/NYPA February Filing are needed in order to satisfy the requirements of the November 2012 Order. First, West Point suggests that Con Edison should be directed to submit a supplement that assesses other projects now under development. Second, the plan should be modified so as to create a more level playing field between the TOTS and other projects.

White Plains Housing Authority:

The Housing Authority expresses its support that the IPEC should remain in service.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on December 11, 2014

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Patricia L. Acampora
Garry A. Brown
Gregg C. Sayre
Diane X. Burman

CASE 12-T-0502 - Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades.

CASE 13-E-0488 - In the Matter of Alternating Current Transmission Upgrades - Comparative Proceeding.

CASE 13-T-0454 - Application of North America Transmission Corporation and North America Transmission, LLC for a Certificate of Environmental Compatibility and Public Need Pursuant to Article VII of the Public Service Law for an Alternating Current Transmission Upgrade Project Consisting of an Edic to Fraser 345 kV Transmission Line and a New Scotland to Leeds to Pleasant Valley 345 kV Transmission Line.

CASE 13-T-0455 - Part A Application of NextEra Energy Transmission New York, Inc. for a Certificate of Environmental Compatibility and Public Need Pursuant to Article VII of the Public Service Law for the Marcy to Pleasant Valley Project.

CASE 13-T-0456 - The Part A Application of NextEra Energy Transmission New York, Inc. for a Certificate of Environmental Compatibility and Public Need Pursuant to Article VII for the Oakdale to Fraser Project.

CASE 13-M-0457 - Application of New York Transmission Owners Pursuant to Article VII for Authority to Construct and Operate Electric Transmission Facilities in Multiple Counties in New York State.

CASE 13-T-0461 - Application of Boundless Energy NE, LLC for a Certificate of Environmental Compatibility and Public Need Pursuant to Article VII for Leeds Path West Project.

ORDER ESTABLISHING MODIFIED PROCEDURES FOR COMPARATIVE EVALUATION

(Issued and Effective December 16, 2014)

BY THE COMMISSION:

## INTRODUCTION

The Commission initiated these proceedings to consider whether to address the persistent transmission congestion that exists at the Central East and Upstate New York/Southeast New York (UPNY/SENY) electrical interfaces. On August 13, 2014, a notice was issued seeking comments on certain Advisory Staff recommendations regarding: 1) the procedural steps for evaluating the proposed transmission projects; 2) the mechanism for recovering the costs; 3) the methodology for allocating those costs; and 4) how the risk of cost-overruns should be handled (collectively, Advisory Staff Recommendations). By this order, the Commission adopts Advisory Staff's recommended procedural steps, with modifications, as discussed herein. The order also identifies the Commission's preferred approaches for cost recovery, cost allocation, and risk-sharing.

A number of the comments question the need for a transmission solution to the identified congestion. The Commission responds to those concerns by expanding the process to address the issue of basis of the need before proceeding to a full Article VII review. Included in the approved process are requirements that Trial Staff prepare a report addressing the question and present its findings in a technical conference open to all the parties so that there can be a full airing and discussion among the stakeholders of the basis of the need for transmission facilities and the viability of potential alternatives.

## BACKGROUND

In the order instituting Case 12-T-0502, the Commission explained that the transmission corridors that include the Central East and UPNY/SENY electrical interfaces were persistently congested and contributing to higher energy costs and reliability concerns. The Commission recognized that upgrades to those sections of the transmission system could produce various benefits for New York, including: 1) enhancing system reliability, flexibility, and efficiency; 2) reducing environmental and health impacts; 3) increasing diversity in supply; 4) promoting job growth and the development of new efficient generation resources upstate; and, 5) mitigating reliability problems that may arise with expected generator retirements.[1]

The Commission sought Statements of Intent from transmission owners and other developers proposing projects to increase the UPNY/SENY transfer capacity by approximately 1,000 MW.[2] On January 25, 2013, six interested parties offered

[1] Case 12-T-0502, Order Instituting Proceeding (issued November 30, 2012), pp. 1-2.

[2] Case 12-T-0502, Order Instituting Proceeding (issued November 30, 2012), p. 2. A technical conference was held on December 17, 2012, in order to explain the purpose and information requirements for the Statements of Intent, and the process for reviewing specific projects. Case 12-T-0502, Notice of Technical Conference (issued November 30, 2012).

proposals intended to address the Commission's objectives.[3] Supplemental information related to the Statements of Intent was subsequently requested by February 15, 2013.[4]

On February 7, 2013, comments were sought on proposed rule changes to streamline the certification process under Article VII of the Public Service Law (PSL) by avoiding the need for future applicants to seek case-specific routine waivers, and to clarify certain regulatory requirements.[5] On April 22, 2013, the Commission adopted the proposed rule changes under PSL Article VII, with modifications, and established procedures for a comparative evaluation of proposed AC project applications, while outlining additional procedural steps.[6] The Commission also directed Department of Public Service Staff (Staff) to

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[3] Statements of Intent were filed by: 1) North America Transmission, LLC and North America Transmission Corporation (collectively, NAT); 2) Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc./ Orange & Rockland Utilities, Inc., Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric & Gas Corporation/ Rochester Gas and Electric Corporation, New York Power Authority, and the Long Island Power Authority (collectively, the New York Transmission Owners (NYTOs)); 3) West Point Partners, LLC; 4) Cricket Valley Energy Center, LLC; 5) NextEra Energy Resources, LLC (NextEra); and, 6) Boundless Energy NE, LLC (Boundless).

[4] Case 12-T-0502, Notice of Information Requirements (issued February 12, 2012).

[5] Case 12-T-0502, Notice Soliciting Comments (issued February 7, 2013).

[6] Case 12-T-0502, Order Establishing Procedures for Joint Review under Article VII of the Public Service Law and Approving Rule Changes (issued April 22, 2013) (April 2013 Order). A two-step review process was established involving the submission of initial application materials, scoping documents, and proposed schedules by October 1, 2013 (referred to as "Part A" application materials), and the submission of the remaining Article VII application materials (referred to as "Part B" application materials) on a schedule to be set by an Administrative Law Judge (ALJ).

develop a straw proposal addressing mechanisms for cost recovery, mechanisms for allocating cost-overrun risk between developers and ratepayers, and methods for allocating project costs among ratepayers. Further, the Commission advised that other rule changes might be necessary to facilitate the comparative evaluation and directed Staff to prepare a proposal identifying such changes.[7]

On May 29, 2013, a notice was issued seeking comments on Staff's proposed procedures to facilitate a comparative evaluation of multiple projects on a common record. Staff also proposed rule changes for how projects that are not subject to Article VII of the PSL would be reviewed, including the content for such applications (collectively, May 2013 Staff Proposal).[8]

On July 10, 2013, a notice was issued soliciting comments on a separate Staff proposal to address the allocation and recovery of project costs, and mechanisms for allocating risk between developers and ratepayers (collectively, July 2013 Staff Proposal).[9] The July 2013 Staff Proposal focused on the establishment of a State mechanism for allocating and recovering costs, while recognizing that an alternative cost recovery

[7] On May 14, 2013, Staff hosted a technical conference to discuss the process with potential applicants and other interested parties and to answer questions. Case 12-T-0502, Notice of Technical Conference (issued April 29, 2013); Case 12-T-0502, Technical Conference Agenda (issued May 10, 2013).

[8] Case 12-T-0502, Notice Soliciting Comments (issued May 29, 2013). On June 17, 2013, Staff convened an additional technical conference to further discuss the process set forth in the April 2013 Order and to answer questions. Case 12-T-0502, Notice of Technical Conference (issued May 31, 2013).

[9] Case 12-T-0502, Notice Soliciting Comments and Scheduling Technical Conference (issued July 10, 2013). The July 10, 2013 notice also advised interested parties of a technical conference to discuss the July 2013 Staff Proposal. The conference was subsequently held on August 1, 2013.

mechanism might be available pursuant to the New York Independent System Operator, Inc's (NYISO) transmission planning process to address Public Policy Requirements, as approved by the Federal Energy Regulatory Commission (FERC).[10]

On September 19, 2013, the Commission addressed the May 2013 Staff Proposal and adopted procedural and substantive rules to help expedite and process proposed solutions. The Commission also directed the assigned ALJ(s) to "consider, promptly after the initial applications are filed, whether an early screening would help streamline the process and serve the goal of obtaining congestion relief at the least cost to ratepayers, and in the 2014-2018 timeframe set out in the Energy Highway Blueprint."[11]

On October 1, 2013, four AC transmission developers submitted Part A application materials for consideration (i.e., NAT, NextEra, Boundless, and NYTOs). Thereafter, the ALJs analyzed and ruled on deficiencies alleged in the applications. On February 14, 2014, the NYISO filed an initial screening-level analysis of the incremental transfer capability of each project. At a technical conference held on March 19, 2014, the NYISO provided in-depth explanations of its process and results for the initial screening-level analysis.

On February 21, 2014, the Commission stated that it would accept proposals that contribute to the targeted level of

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[10] FERC Docket No. ER13-102 et al., New York Independent System Operator, Inc., Order on Rehearing and Compliance, 148 FERC ¶61,044 (issued July 17, 2014). The Commission issued a Policy Statement on August 15, 2014, in Case 14-E-0068, which established generic procedures that will be used to guide the implementation of the Commission's role in the NYISO's public policy planning process.

[11] Case 12-T-0502, Order Adopting Additional Procedures and Rule Changes for Review of Multiple Projects Under Article VII Of the Public Service Law (issued September 19, 2013), p. 11.

congestion relief, even if they do not, individually, provide the full 1,000 MW of additional transfer capability. The ALJs were also directed to establish a process that offers the current applicants an opportunity to "submit alternatives to their existing proposals, incorporating, to the maximum extent possible, projects that can be contained within the bounds of existing rights-of-way."[12]

The ALJs conducted a telephone conference on February 27, 2014 to discuss the establishment of such a process. Thereafter, on April 10, 2014, the parties were advised by the ALJs that further guidance on the next procedural steps would be forthcoming that would also address how the NYISO cost recovery mechanism for public policy requirements should apply to the ongoing AC Transmission proceeding. After considering various comments and requests for clarification made in the course of these proceedings, Advisory Staff developed recommendations regarding procedural matters, cost recovery, cost allocation, and risk-sharing. On August 13, 2014, the Commission sought comments on the Advisory Staff Recommendations.[13] The deadline for initial comments was September 2, 2014, and reply comments were due September 12, 2014.[14]

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[12] Case 12-T-0502 et al., Order Authorizing Modification Of The Process To Allow For Consideration Of Alternative Proposals (issued February 21, 2014) (February 2014 Order), p. 4.

[13] Case 12-T-0502 et al., Notice Seeking Comment on Attached Advisory Staff Recommendations (issued August 13, 2014).

[14] Case 12-T-0502 et al., Letter Ruling On Extension Request (issued August 27, 2014); Case 12-T-0502 et al., Notice Regarding Reply Comments (issued September 5, 2014).

## ADVISORY STAFF RECOMMENDATIONS

Procedural Matters

Advisory Staff recommends that the Commission conduct a comparative evaluation of the proposals in order to identify the project or group of projects that best meet the objectives of these proceedings and therefore should continue towards certification. To accomplish this, Advisory Staff would require applicants to submit their existing proposals, revisions to those proposals, or any alternatives developed in response to the Commission's February 2014 Order, for a comparative evaluation. Advisory Staff suggested a deadline of November 14, 2014, for applicants to file certain information identified in Appendix B of the Advisory Staff Recommendations and a deadline of January 19, 2015, for applicants to file additional materials identified in Appendix C. This information would be reviewed using the following criteria: (1) the amount of increased transfer capability that each proposal offers; (2) the cost of the proposal(s) to ratepayers; (3) electric system impacts, emissions reductions, and production cost impacts, measured in terms of overall changes to electric generation dispatch; (4) the extent of any additional rights-of-way (ROW) that the applicant(s) will need to acquire in order to build and operate the proposed facility(ies); (5) the application of innovative technologies to enhance transfer capability or reduce the physical footprint of the project; and, (6) an initial assessment of environmental compatibility, including visual impacts. An analysis of any alternative risk-sharing proposals would be used in assigning a cost to the potential for cost-overruns.

Trial Staff would submit the results of its comparative evaluation to the Commission in the form of a report and motion, upon which all parties would have the opportunity to comment. The motion portion of the document would contain Trial Staff's proposal as to which projects best meet the Commission's objectives and should therefore proceed, with an expectation of public policy benefit and cost recovery, and which projects should proceed on their own, at the developers' option, without any such expectations. At the time of considering the report and motion, the Commission would also consider whether it should request one or more of the applicants to propose their projects to the NYISO as potential transmission solutions under the NYISO's public policy planning process. The individual Article VII cases would thereafter proceed before the assigned ALJs under the Commission's existing regulations. A table of proposed milestones and deadlines is contained in Appendix A of the Advisory Staff Recommendations.

Cost Recovery

Advisory Staff recommends that the Commission decline, at this time, to adopt a State rate-based cost recovery mechanism, as had been suggested in the July 2013 Staff Proposal. Advisory Staff concludes that there is no compelling reason to adopt such a mechanism since the NYISO's tariff provides a cost recovery mechanism for transmission projects that meet certain Public Policy Requirements, which may well include the congestion relief being sought in these proceedings. Alternatively, a transmission developer could seek cost recovery under Section 205 of the Federal Power Act, by filing directly with FERC.

Advisory Staff recommends that the Commission coordinate the comparative evaluation phase of these proceedings with the NYISO public policy planning process so as to potentially afford applicants an opportunity for cost recovery through FERC.[15] The NYISO tariff provides for the recovery of costs incurred by an applicant in preparing a proposed transmission solution in response to a request by the Commission, regardless of whether the project is ultimately selected by the NYISO as the best solution. Moreover, Advisory Staff notes that a project that is ultimately granted a certificate under Article VII of the PSL and that has been identified as the most cost-effective or efficient by the NYISO would be able to recover its development costs under the NYISO tariff.

Cost Allocation

Advisory Staff recommends that 75% of project costs be allocated to the economic beneficiaries of reduced congestion, consistent with the methodology embodied in the NYISO's Congestion Assessment and Resource Integration Study process, and that the other 25% of the costs be allocated to all customers on a load-ratio share. The net result would be about 90% of the costs being allocated to customers in the downstate region, and about 10% to upstate customers, instead of a 79%/21% split previously proposed in a Straw Proposal issued on July 10, 2013, in Case 12-T-0502. According to Advisory Staff, this revision recognizes that the primary benefit of the projects will be reduced congestion into downstate load areas, but also acknowledges that there will be some benefits accruing to upstate customers in the form of increased reliability and reduced operational costs.

[15] On August 1, 2014, the NYISO commenced its public policy planning process by soliciting filings by parties proposing transmission needs believed to be driven by Public Policy Requirements.

Risk-Sharing

In order to balance the competing interests of ratepayers and developers, Advisory Staff recommends that the Commission treat project cost estimates as binding applicant bids subject to risk-sharing of cost over-runs or under-runs between ratepayers and independent developers/investor-owned utility shareholders. Specifically, Advisory Staff explains that the developer would bear 20% of the actual cost over-runs, while ratepayers would bear 80% of those costs. If actual costs come in below the bid, the developer would retain 20% of the savings.

In addition, as a component of the risk-sharing model, if the developer is seeking incentives from FERC above the base return-on-equity otherwise approved by FERC, Advisory Staff recommends that the developer not receive any incentives above the base return-on-equity on any cost overruns over the bid price. Applying the risk-sharing model, the bid price would cap the costs that may be proposed to FERC for incentives. The initial bid price, however, could be updated to reflect additional identifiable and verifiable costs associated with Commission-imposed modifications and mandates, the cost of which the developer could not have anticipated in formulating the initial bid price. These additional costs would need to exceed a materiality threshold of 5% above the initial bid price. Advisory Staff also recommends that developers be allowed to propose alternative risk-sharing proposals if they are submitted in addition to the developer's bid prepared on the partial pass-through model. Advisory Staff maintains that this approach would allow the projects to be evaluated on a comparable basis.

Advisory Staff recommends that the Commission adopt an approach whereby the NYISO would include the risk-sharing proposal as part of the cost allocation prescribed under the

Public Policy Requirement. Any successful developer would similarly include the risk-sharing proposal when filing at FERC for cost recovery.

## COMMENTS

Approximately 2,300 public comments have been received in these cases since their inception. The overwhelming majority of the comments are in opposition to building any overhead power lines because of adverse visual impacts that would occur in the Hudson Valley, the loss or impairment of agricultural uses, and resultant adverse impacts on property values or from the taking of land. In general, the people expressing opposition believe that the proposed projects are either unnecessary or will cost too much in relation to alternative technologies or resources such as undergrounding, local grid enhancements, demand-side management, and renewable resources. Many argue that undergrounding may have a higher initial cost, but will be less expensive to maintain in the long run considering the newly higher threat of severe storms due to climate change. Many argue that the need for more power should be addressed in the Reforming the Energy Vision (REV) proceeding or as part of the Clean Energy Fund. Another common concern is that property values are currently being harmed by the pendency of the proposed projects. A few people mentioned concerns about the potential health effects of power lines or the use of herbicides to treat the right-of-way.

### Procedural Matters

Several commenters raise issues, which they consider to be threshold matters, related to the need for 1,000 MW of AC transmission upgrades, and how this need relates to other Commission proceedings, such as the REV initiative in Case 14-M-

0101.[16] Scenic Hudson, Inc. (Scenic Hudson) suggests that the AC transmission upgrade proceeding should be suspended pending a determination of need for the proposed projects, as well as an analysis of alternative non-transmission congestion solutions.[17] Clinton similarly seeks to postpone the Commission's consideration of 1,000 MW of AC congestion relief until after the REV proceeding is completed.[18]

A concerned citizen urges the reconductoring of existing transmission lines to reduce line losses and increase capacity, while providing time to implement REV initiatives and integrate new renewable resources.[19] Congressman Gibson supports upgrades to the transmission system, but urges the Commission to examine all alternatives, such as buried cable, to minimize impacts.[20] Congressman Gibson also requests that the Commission conduct a full and transparent public comment process, and expeditiously address the concerns about the need for AC transmission upgrades. Assembly-member Barrett urges the Commission to close down the current AC Transmission proceedings and look at opportunities to be innovative and visionary in our energy policies in New York State to meet the real needs before moving forward.

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[16] Town of Clinton, Clinton Concerned Citizens, and Pleasant Valley Concerned Citizens comments (Clinton) (filed August 28, 2014); Town of Pleasant Valley and Farmers and Families of Livingston (Pleasant Valley) comments (filed September 2, 2014); Dutchess County of New York (Dutchess County) comments (filed August 20, 2014); Dutchess Land Conservancy comments (filed September 2, 2014); Farmers and Families for Claverack comments (filed August 26, 2014); Town of Milan comments (filed August 27, 2014).

[17] Scenic Hudson comments (filed September 2, 2014), pp. 1, 4.

[18] Clinton comments (filed August 28, 2014), p. 2.

[19] Todd M. Pfleger comments (filed August 26, 2014).

[20] Congressman Gibson comments (filed August 29, 2014).

The Department of Environmental Conservation (DEC) seeks clarification of the impact that the comparative evaluation process and the NYISO public policy transmission planning process will have upon the required statutory findings under Article VII of the PSL, such as the basis of need. DEC requests further clarification of the extent to which procedures previously adopted by the Commission will apply going forward. In establishing new procedures, DEC asks that the Commission define the scope, factual basis, and legal significance of the findings and determinations that will be made at each phase of these proceedings.

NextEra supports the Advisory Staff Recommendations in their entirety, but requests clarification whether the Part A cost estimates will be binding estimates for purposes of the comparative evaluation and for calculating the risk allocation mechanism. If so, NextEra asks for clarification as to how the cost estimates provided in Part B would differ.

Entergy supports the proposal to utilize the NYISO public policy planning process.[21] NextEra suggests that the Commission designate the relief of transmission congestion, through a 1,000 MW increase in transfer capability, as a Public Policy Requirement within the meaning of the NYISO's planning process.

Scenic Hudson suggests the timeframes proposed under the Advisory Staff Recommendation are unrealistically short. These include: 1) three weeks for the NYISO to conduct an analysis of Part A proposals; 2) four weeks for Trial Staff to prepare its report and motion ranking the proposals; and, 3)

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[21] Entergy Nuclear FitzPatrick, LLC, Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, and Entergy Nuclear Operations, Inc. (collectively, Entergy) comments (filed September 2, 2014), p. 2.

three weeks for public comment on the Trial Staff report and motion.[22] Scenic Hudson seeks to extend the public comment period to a minimum of 60 days.[23] DEC requests an additional week to review Trial Staff's report and motion. The Otsego County Conservation Association, Inc. (OCCA) also requests an extension of this deadline.[24] OCCA requests clarification that public comments will be sought on the Part A submissions due January 19, 2015.

Clinton notes the proposed time schedule significantly extends the length of these proceedings and that the delays have had adverse negative impacts on residents, including property values. Clinton also seeks additional time to receive intervenor funding and to hire experts to analyze the documents submitted by applicants, the NYISO, and Staff.

The NYTOs suggest that the deadline for providing notification that a System Reliability Impact Study (SRIS) is in progress should be extended to March 2, 2015 to align with the date for Trial Staff's submission of its report and motion.[25] According to the NYTOs, this extension will assist developers in assessing whether to incur SRIS costs, help the NYISO manage resources, and allow project details to remain confidential until after the January 2015 submittal. Further, the NYTOs request that developers be allowed to propose a process to protect the confidentiality of proposals during the project submittals. This would include prohibiting developers from

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[22] Dutchess County raises similar concerns with the proposed schedule.

[23] Scenic Hudson comments (filed September 2, 2014), p. 9.

[24] OCCA comments (filed September 3, 2014).

[25] On October 27, 2014, the ALJs issued a ruling indefinitely postponing the deadline for applicants to provide notice that an SRIS was in progress pursuant to the NYISO tariff, pending further guidance from the Commission on the future process.

substantially modifying or submitting alternative proposals beyond the submission due date.

The NYTOs also request clarification as to whom to submit the filings, and suggest that application materials should be submitted only in project-specific cases. Regarding service, the NYTOs maintain that an email filed with the Secretary and served upon all parties and the statutory service list should be sufficient, unless a party requested to be served by mail when they intervened. Further, the NYTOs suggest that the additional intervenor funding required under Article VII should be submitted with the applications for individual projects, which are projected to be submitted in May 2015.

In reply comments, Clinton criticizes the lack of involvement by the ALJs in the proposed comparative evaluation process. Clinton believes that the ALJs would ensure that the interests and concerns of the residents and municipalities most impacted will be acknowledged and responded to in a meaningful manner.

In reply to concerns DEC expressed about when further factual development on the issue of need would be appropriate in the proceedings, the Town of Pleasant Valley and Farmers and Families for Livingston (Pleasant Valley/Livingston) suggest that need should be established first and fully. Pleasant Valley/Livingston argues that there is no reliability need, that congestion has been decreasing annually, that there has been no showing that reduced congestion during peak periods would enable generally off-peak wind energy to reach downstate consumers, that REV will alleviate congestion, that generation attracted by the new capacity zone may render additional transmission unnecessary, and that pursuing energy efficiency is significantly more cost-beneficial than pursuing transmission. Scenic Hudson agrees with DEC that it is necessary for the

Commission to clarify when and how the need issues will be addressed in these proceedings. Boundless requests that all matters decided in these proceedings not be subject to re-litigation in the individual Article VII proceedings.

Pleasant Valley/Livingston also expresses concern that, since the NYISO would be doing electric system studies as part of the winnowing process, demand side management and energy efficiency solutions will be given short shrift because of the heavy influence of the transmission and generation owners in the NYISO governance structure, and because most parties do not understand the modeling used by the NYISO. Pleasant Valley/Livingston requests that the Commission establish a process to enable the parties to verify that the NYISO analyses are robust, independent, and produce reasonable results. Clinton raises similar concerns about the transparency of the NYISO study process.

Pleasant Valley/Livingston suggests that these proceedings are operating outside the confines of the FERC-approved and mandated NYISO transmission planning process, and as such, should be suspended until both the NYISO process and the REV proceeding have been completed. Clinton takes a similar position that these proceedings should be suspended. Scenic Hudson also believes that the proceedings should be suspended until the NYISO Public Policy Planning Process is complete. Scenic Hudson argues that proceeding with project evaluations would be inefficient because it does not believe that congestion relief meets the public policy standard and that non-transmission alternatives need to be given equal treatment with transmission. According to Scenic Hudson, congestion relief should not be designated as a public policy since it is not required by a law or regulation as required by the NYISO tariff.

In reply to the requests for suspension, NextEra asserts that no basis has been provided to conclude that an incremental increase in distributed generation will resolve the persistent congestion in the transmission system that resulted in the initiation of these proceedings, and that, in any event, the Commission will not issue an Article VII certificate without determining that there is a need for the facility.

In reply to the parties questioning need, Boundless submits that FERC established the lower Hudson Valley New Capacity Zone based on the existing limitation on the transfer capability across the UPNY/SENY interface due to a constraint across this interface of approximately 849 MW, and therefore these proceedings should be continued by the Commission without the extensive delay called for by certain parties.

NextEra agrees with the suggestion by the NYTOs that applicants be prohibited from substantially modifying their proposals or submitting alternative proposals for consideration in the comparative stage of the proceeding after the deadline for the revised submissions. In reply to a request for clarification made by the NYISO, NextEra argues that the Commission has made it clear that developers should be allowed to submit multiple alternative project designs/routes as part of their applications.

In response to the NYTOs’ suggestion that the deadline for applicants to have a System Reliability Impact Study in progress for each preferred and alternate project design be extended to March 2, 2015, NextEra recommends that it be extended to May 31, 2015, to accommodate the cumulative time necessary to complete all of the steps leading from the filing of an interconnection request to the start of an SRIS.

Evaluation Criteria

Regarding the criteria to be used in ranking the proposals, several parties request that specific weights be assigned to each criterion.[26] Scenic Hudson suggests eliminating any project from consideration that would result in construction outside of an existing transmission line footprint, in terms of length, height, and width. Clinton similarly interprets the February 2014 Order as requiring all proposals to stay within existing ROWs.[27] OCCA recommends that minimizing further ROW impacts should be a primary factor. Dutchess Land Conservancy maintains that visual impacts should be ranked as a top consideration.

New York State Senator Gipson supports the comparative evaluation process using the criteria proposed by Advisory Staff, but suggests the most important criteria should be public impacts from the physical footprint and environmental compatibility, including visual impacts.[28] Senator Gipson suggests that the cost to ratepayers should include the impact on property values.

DEC seeks clarification of the criteria that would be used in performing an initial environmental assessment. The Department of Agriculture and Markets (Ag & Mkts) maintains that it should be involved in the ranking of the proposals and the identification of mitigation steps related to agricultural resources.[29]

[26] Scenic Hudson comments (filed September 2, 2014), p. 10; Farmers and Families for Claverack comments (filed August 26, 2014); OCCA comments (filed September 3, 2014); Town of Milan comments (filed August 27, 2014); NAT comments (filed September 2, 2014).

[27] Clinton comments (filed August 28, 2014), p 3.

[28] Senator Gipson comments (filed August 26, 2014).

[29] Ag & Mkts comments (filed September 2, 2014).

The NYISO requests clarification as to: 1) the scope of the studies (i.e., the number of projects and studies for each project); 2) the timing of the studies, which may require more than three months to complete depending on the scope; and, 3) how the costs of the analyses would be recovered. The NYISO asks the Commission to provide for the NYISO's recovery of its actual costs in performing the requested studies.

The NYTOs note that the Transmission Owner Transmission Solutions (TOTS) proposed in these proceedings were previously selected as part of the Indian Point Contingency Plan approved by the Commission.[30] Accordingly, the NYTOs propose that the TOTS should not participate in the comparative evaluation process or be required to provide additional information.[31]

The NYTOs propose four additional criteria beyond the six criteria proposed by Advisory Staff for use in the comparative analysis phase. These include: 1) the project's resiliency and its impact on the total transmission system resiliency (i.e., storm hardening); 2) the project's impact on system reliability; 3) the project's robustness and expandability to provide the transmission system the long-term flexibility to respond to future load and generation needs; and, 4) economic benefits to the State (i.e., job growth, tax base expansion, more efficient use of existing generating resources, development of efficient and lower-cost new generating resources

[30] Case 12-E-0503, Generation retirement Contingency Plans, Order Accepting IPEC Reliability Contingency Plans, Establishing Cost Allocation And Recovery, And Denying Requests For Rehearing (issued November 4, 2013).

[31] NYTO comments (filed September 2, 2014), p. 8. On November 17, 2014, NYPA and NYSEG withdrew their respective portions of the Marcy South Series Compensation Project from further consideration in these proceedings.

in upstate areas, and fewer reliability issues resulting from retirement of existing upstate generators).

The NYTOs request that the NYISO perform a complete transfer analysis, including thermal and voltage impacts, on the interfaces subject to the original scope of study and on any additional interfaces affected by the proposals. The NYTOs also suggest additional information requirements to improve the quality of the cost estimates. In particular, they recommend that each estimate should include, by discrete transmission element (i.e., each transmission line, each substation addition), information regarding: 1) material cost; 2) labor cost broken out by engineering, construction, and survey; 3) regulatory permitting and legal fees; 4) property acquisition; 5) taxes; 6) program/project management; 7) Allowance for Funds Used During Construction (AFUDC); and, 8) risk and contingency. The NYTOs indicate these estimates should be provided in current year dollars and as-spent dollars.

NAT suggests a list of information requirements that include items identified by the NYTOs. NAT requests that estimates of this information be represented in total capital cost by year-of-occurrence dollars. In order to minimize risk premiums, NAT suggests allowing bids to be indexed to inflation and the costs of labor, steel, aluminum, and other construction materials.

NAT asks the Commission to identify the methodology and assumptions that will be used to identify the transfer capability under the first criterion. NAT suggests that the second criterion (cost) should be evaluated based on total cost, cost per MW of transfer capability, and cost relative to benefits. The third criterion (electric system impacts), according to NAT, should evaluate production cost energy savings, load energy savings, and load capacity market savings.

NAT also suggests that emissions reductions calculated under the third criterion should instead be considered as part of the sixth criterion (environmental compatibility).

Regarding the analysis of ROWs under the fourth criterion, NAT seeks clarification that some additional private ROWs would be acceptable, and that the analysis of additional ROWs would relate to private ROWs. NAT suggests that the fourth and sixth criterion (additional ROWs and environmental compatibility, respectively) be combined since additional ROW is one aspect of environmental compatibility. NAT further contends that the fifth criterion (innovative technologies) should be eliminated because innovative technology was not an original goal, or alternatively it should be reflected in the first and fourth criterion (transfer capability and additional ROWs, respectively).

Boundless argues that the appropriate studies should be performed under normal dispatch conditions. Boundless also contends that the NYISO should perform studies using the same approach the NYISO took in justifying the lower Hudson Valley capacity zone, which would provide a basis for seeking relief at FERC from the costs associated with the new zone. Boundless requests a technical conference to discuss modeling protocols and assumptions before the NYISO performs any additional analysis. Boundless maintains that the ALJs should rank the projects, rather than Trial Staff.

NextEra does not object to the proposals by the NYTOs and NAT that cost estimates be provided using certain categories, but does not believe that the NYTOs' suggestion to use the Association for the Advancement of Cost Engineering International Recommended Practice as a reference point is appropriate because that practice is relevant to process plants and is not used as an industry standard for estimating costs of transmission facilities. In addition, NextEra recommends that the parties be required to provide estimates escalated to the year in which the project will be built, as recommended by NAT, rather than current dollars, to allow a relevant comparison of the projects.

Boundless supports the suggestion that the project cost estimates should be of high quality, but opposes the detailed requirements proposed by the NYTOs because they would significantly raise the cost of preparing the estimates and the cost to Boundless and the other non-incumbent generators would outweigh the purported advantages of the more detailed information, unless reimbursement of the cost to prepare the estimates is provided to all parties.

In response to DEC's comments, Pleasant Valley/Livingston states that it agrees that the Part A evaluation needs to include environmental criteria. Pleasant Valley/Livingston also agrees with NAT that the relative weights assigned to evaluation criteria should be stated. Boundless also agrees with the comments of NAT and others on the criteria and with a request by Otsego County Conservation Association, Inc. that ROW impacts be given greater emphasis than other criteria.

In response to a proposal by the NYTOs that four additional criteria be added (resiliency, system reliability, robustness and expandability, and economic benefits to New York), NextEra believes them to be unnecessary, as the originally stated criteria appropriately reflect the key goals of the Energy Highway Blueprint and that supplementing the review process with these additional criteria, many of which are difficult or impossible to quantify, may make the comparison process unduly burdensome without a corresponding increase in the likelihood of identifying the project that best addresses the key goals of the Energy Highway Blueprint. In contrast, Boundless supports the additional criteria proposed by the NYTOs.

Boundless questions the proposal by Ag & Mkts that other State agencies participate in the ranking of proposals over concerns that such participation not be done in secret, but does not appear to oppose written input to DPS Staff by other State agencies in the form of comments.

In reply to comments filed by the NYTOs asserting that the Ramapo to Rock Tavern project and the Marcy South series compensation project (MSSC) have already been selected for construction by the Commission and therefore do not need to be comparatively evaluated in these proceedings, Entergy argues that the MSSC project (which had not yet been withdrawn from the AC Transmission proceedings at the time Entergy's comments were filed) should participate in the comparative evaluation portion of this proceeding. Boundless submits that the MSSC project should be voluntarily withdrawn or the Commission should remove the project from further consideration as a simplifying measure. Boundless also seeks a clarification as to how the withdrawn projects will be treated for system modeling purposes.

Cost Recovery and Cost Allocation

Dutchess County supports cost recovery through FERC authorized tariffs, but opposes allowing a developer, which is ultimately not selected to build a project, to recover its costs in proposing a solution to the NYISO. Dutchess County seeks an evaluation of cost impacts on ratepayers by utility franchise, broken down for residential, commercial, and industrial customers.

Multiple Intervenors (MI) opposes Advisory Staff’s recommended cost recovery approach and maintains that the proposal is not consistent with cost causation principles and fails to ensure customer rate impacts are adequately minimized. According to MI, recovering costs on a volumetric MWh basis is contrary to cost causation principles and the Commission's precedence, and is inequitable to high-load-factor customers.

MI supports the July 2013 Staff Proposal to allocate costs among utility service classes based on class contribution to peak demand, and then recovered on a per kW basis from demand-metered customers. MI further supports recovery of costs over the projected service life of the transmission facility in order to minimize rate impacts on customers.

The NYTOs support cost recovery through FERC-approved tariffs, but suggest that they should be allowed to propose a State-based cost recovery mechanism where it may be reasonable, such as where an upgraded project replaces pre-existing facilities.

Entergy supports adoption of the proposal to file a cost recovery and allocation methodology with FERC as the entity with jurisdiction over such matters.

Dutchess County argues that there is no basis to include it within the downstate region that is expected to be the primary beneficiary. Accordingly, if a transmission project moves forward, Dutchess County seeks to ensure Zone G would be considered in the upstate region.[32] Senator Gipson supports a 90% allocation of costs to downstate customers, and proffers to define downstate to include Nassau, Suffolk, Westchester, and New York City.

MI supports Advisory Staff's allocation of approximately 90% of the costs to SENY customers and 10% to UPNY customers. This approach, MI asserts, is consistent with the

[32] Dutchess County comments (File August 20, 2014).

beneficiaries pay principle given that the primary benefits of the transmission project would be reduced congestion and economic benefits for downstate load areas.

The NYTOs maintain that their rights under the Federal Power Act allow them to propose their own cost allocation methods, and ask the Commission to clarify that such alternative cost allocation methods are acceptable.

In response to comments that oppose cost recovery for projects that are not ultimately selected, NextEra argues that the competition provided by non-winning bidders is what keeps the ultimate project costs at a level that reflects effective competition, and that new entrants/non-incumbents will not be attracted to add to the competition if incumbent transmission owners can likely recovery their prudent development costs but new entrants/non-incumbents cannot. NextEra believes that the financial and other benefits that will accrue to ratepayers from preserving a competitive dynamic in these proceedings will far outweigh the expense to consumers of the cost recovery mechanism recommended by Advisory Staff.

In response to the NYISO’s comments as to what development costs may be recoverable under its tariff, Boundless submits that the language of the tariff provision is better read as covering cost recovery for the development of the project which was selected by the Commission for submission to the NYISO. According to Boundless, even if the cost directly associated with participation in these proceedings before the Commission are excluded, as presumably would meet the NYISO’s interpretation, the tariff section would provide for more extensive cost recovery than suggested by the NYISO.

In reply to the NYISO’s request for compensation for studies it would perform at the request of the Commission, Boundless challenges the NYISO's authority to charge the

Commission for such study work, argues that transferring such costs to applicants is contrary to the policy and goals of FERC which has encouraged the regional independent system operators to undertake such a planning function, and notes that the NYISO has a tariff which permits it to collect all of its planning expenses at no risk. Boundless notes that the NYISO submitted the Screening-Level Analysis on February 14, 2014 in these proceedings, without reimbursement. Boundless also argues that nothing in Article VII of the PSL authorizes the Commission to assess charges on developer-applicants for the processing of their applications. According to Boundless, the Commission cannot simply accept the submission of certain charges from the NYISO and then impose them on the current parties as a condition of continuing in these proceedings. In addition, Boundless cautions that if the Commission were to allow these costs to be charged to applicants, such charges would unfairly and greatly exacerbate the distinction between incumbent and non-incumbent developers because incumbents may be able to recover their prudently incurred development costs from ratepayers, whereas no vehicle has been established for non-incumbents to recover such development costs.

Boundless states its understanding is that a successful developer will be able to recover its development costs under a FERC cost recovery order. Therefore, Boundless suggests that the NYISO prepare cost records of its studies for developers in these proceedings in sufficient detail so that a developer which seeks a cost recovery order from FERC will be able to include the NYISO's study costs in its presentation to FERC as an element of cost to be recovered.

Pleasant Valley/Livingston believes that developers should pay for the NYISO study costs based on their opportunity to gain; unsuccessful developers should not be allowed to shift their business risk of participating to ratepayers. Clinton echoes those concerns, finding it completely unacceptable to allow developers to proceed without any significant financial risk. Scenic Hudson also believes that developers, not ratepayers, should pay for NYISO study costs given that developers stand to gain if successful, and therefore have also assumed the risk of not being selected.

Pleasant Valley/Livingston also believes that DPS Staff needs to tightly define the study work scope of the NYISO to ensure the process is manageable and not unduly burdensome, and that such continuing and open-ended incremental costs can be avoided by placing the proceeding on hold until the REV proceeding concludes and the need for more overhead AC transmission is established.

The NYTOs agree with the NYISO that the NYISO should be compensated for its study costs, but urges that mechanisms be adopted to reduce those costs by eliminating redundant studies and allowing developers to self-perform some of the studies. NAT believes that the NYISO study costs should be paid proportionally by the developers selected by the Commission at the conclusion of the comparative evaluation phase of the proceedings, with payment due within 30 days of the Commission order. NextEra suggests that following completion of studies by NYISO, the developers/applicants participating in that stage of the proceedings should reimburse NYISO for its study costs on an equal per capita basis.

The New York Municipal Power Agency (NYMPA) supports Advisory Staff's proposed 75%/25% CARIS/Load Ratio Share cost allocation as more closely based on the quantifiable economic benefits of congestion relief than the initial Straw Proposal, even though NYMPA believes that Advisory Staff failed to satisfactorily quantify how generic (non-congestion reduction) benefits would benefit upstate when most such dispatch cost savings would likely accrue to downstate loads. In response to the NYTOs' comments regarding alternate, case-specific cost allocation methodologies, NYMPA states that it favors a pre-determined single cost allocation methodology rather than a flexible method as proposed by the NYTOs because the pre-determined method has been fully vetted and is consistent with FERC's policy that there be transparency in determining the chosen methodology. Alternately, NYMPA supports imposing a high burden of proof, including a precise quantification of benefits, for any other individually proposed cost allocation methodology.

Risk-Sharing

Pleasant Valley and Scenic Hudson object to the Advisory Staff Recommendation to adopt an 80%/20% risk allocation because it incentivizes cost overruns and makes ratepayers responsible for 80% of cost overruns. Farmers and Families for Claverack take the same position. Dutchess County similarly maintains that the Advisory Staff Recommendations allow too much of a return on cost overruns for developers, and thus expresses a preference for a fixed price bid, without sharing, but the possibility of a tightly controlled verifiable price true-up if "material" or above 5%.

MI supports the Advisory Staff Recommendations with respect to risk-sharing as a reasonable approach.

The NYTOs argue that Advisory Staff's recommendation to deny cost recovery for certain cost over-runs contradicts with FERC's approach, which provides full cost recovery of prudently incurred investments. The NYTOs contend that assuming the risks of cost overruns will lead to higher capital costs. The NYTOs advocate that any risk-sharing mechanism should be consistent with FERC's policies and subject to FERC's approval.

In reply to comments that seek to shift more risk onto the developers, the NYTOs reiterate that any risk-sharing which does not allow full recovery of prudently incurred costs would be inconsistent with FERC policy. According to the NYTOs, FERC already includes risk-sharing by making projects with cost over-runs subject to loss of transmission return equity adders. The NYTOs oppose the risk-sharing proposal made by Advisory Staff as being inconsistent with FERC policy and also believe that it would result in higher capital costs. Boundless agrees with the Indicated NYTOs on this point.

NextEra, responding to the NYTOs, argues that FERC did not intend to preclude innovative risk and reward-sharing arrangements that might be proposed pursuant to FERC Order No. 1000, and has explicitly approved transmission provider proposals to allow participants in competitive transmission proceedings to include binding cost containment measures to enhance the attractiveness of their bids, which could preclude some degree of cost recovery.[33] In reply to other comments suggesting that the risk-sharing model will incentivize cost overruns because a developer’s penalty in the event of an overrun would be limited to 20%, NextEra argues that a 20% overrun penalty eliminates the possibility of cost recovery for a significant portion of overages and will therefore operate as an incentive for developers to avoid cost overruns.

The NYTOs opposes NextEra’s proposal that the Part A project estimates be binding for the purposes of comparison evaluations and for allocating risk-sharing. The NYTOs caution that these cost estimates are necessarily preliminary and should not be accorded great weight because of uncertainties as to interconnection costs, detailed construction costs, local

[33] NextEra cites California Independent System Operator Corporation, 143 FERC ¶ 61,057, at P 233 (2013).

government compliance costs, and necessary environmental mitigation measures, all of which cannot be accurately determined at this stage in the development process. Boundless similarly opposes the concept of binding bids given the potential of unforeseen contingencies at this early stage of development and the potential for fluctuations in commodity prices. Boundless is also concerned that developers that are large corporations can likely assume more cost risk than developers like Boundless, such that the risk-sharing provision may drive Boundless out of the competition.

## DISCUSSION

The various comments provided by interested parties, stakeholders, and State agencies have significantly contributed to the development of the record in these proceedings. This input is truly appreciated and serves to better inform the Commission’s decision-making. Upon considering these comments, the Commission adopts a comparative evaluation process and schedule for these proceedings that is to be coordinated with the process and schedule for the Commission's determination as to whether transmission congestion at the Central East and UPNY/SENY interfaces creates a transmission need driven by Public Policy Requirements.

In response to the substantial number of comments that question the need for a transmission solution to the identified congestion, the Commission is supplementing the process to address the basis of the need in the comparative evaluation phase of these proceedings. The Commission is requiring that Trial Staff prepare a report addressing the need question and present its findings in a technical conference open to all the parties so that there can be a full airing and discussion among the stakeholders of the basis of the need for transmission facilities and the viability of potential alternatives. The Commission expects all the parties to cooperate and assist Trial Staff in the creation of a record on these issues for the Commission's consideration.

The Commission also adopts methodologies for cost recovery, cost allocation, and risk-sharing. As also discussed below, the Commission clarifies several matters raised in the comments.

Procedural Matters

A comparative evaluation of the proposed projects is necessary to determine which project, or combination of projects, will best achieve the Commission's objectives. The Commission also notes that the question of whether any projects should be evaluated under the NYISO's tariff is presently before the Commission in Case 14-E-0454, where the Commission will consider whether Central East and UPNY/SENY congestion relief should be designated as a Public Policy Requirement driving a need for transmission within the meaning of the NYISO's public policy planning process.[34] The Commission's determination on that issue should be informed by the analyses being conducted in the comparative evaluation phase of the AC Transmission proceedings, and conversely analyses made in the AC Transmission proceedings should inform the decision in the Public Policy Requirements process. Therefore, the Commission will direct Trial Staff to consider comments in Case 14-E-0454 and provide an overall assessment of the benefits and costs of congestion relief as part of the Trial Staff report. The Table of Milestones and Deadlines, attached as Appendix A, identifies the

[34] The procedures to be followed in Case 14-E-0454 comport with the Policy Statement on Transmission Planning for Public Policy Purposes (Policy Statement). Case 14-E-0068, Policies and Procedures Regarding Transmission Planning for Public Policy Purposes, Policy Statement (issued August 15, 2014).

key deliverables and the timing to help guide the completion of the comparative process. These steps, which supplant the procedures previously adopted, are also discussed below.

The milestones and deadlines proposed in the Advisory Staff Recommendations have been revised to accommodate certain additional procedural steps and to reflect an updated time schedule. The four developers shall therefore submit, by January 7, 2015, the information identified in Appendices B and C, which is needed to commence the comparative evaluation, including the powerflow analyses. No substantial modifications of the proposals will be allowed after the submissions due January 7, 2015 until the comparative evaluation process is completed. The additional information identified in Appendix D, which is needed to complete the evaluation, will be due on January 19, 2015. The Commission notes that the information to be submitted in both instances has been augmented to require more specific information from the developers and to place a greater portion of the burden of developing the record on them rather than on Trial Staff. The deadline to provide notification that an SRIS is in progress will be February 27, 2015. That date preserves the confidentiality of the revised proposals prior to their submittal deadlines, but also requires submission of the notification prior to the deadline for parties to comment, and substantially before Trial Staff has to complete its comparative evaluation. The Commission adopts the suggestion to allow comments on these submissions, and establishes deadlines for parties to submit such comments, and for replies. Parties that have information to contribute to the record on these issues should avail themselves of the comment opportunity provided.

The Commission anticipates that the powerflow analyses will be completed by May 13, 2015, and that the production simulations will be completed by May 20, 2015. Trial Staff should thereafter rank the proposals according to the criteria and present a Report and Motion[35] by June 10, 2015, for the Commission's consideration. In addition, to be responsive to the comments received about transparency and the basis of the need for any facilities, Trial Staff should plan to host a technical conference on or about June 17-18, 2015, in order to explain the results in the Report and Motion and answer questions about the modeling and analyses that went into the results. The NYISO, and any other entity that assisted, should also participate in the technical conference. The technical conference will also serve the dual purpose of informing the Public Policy Requirements process. It is anticipated that the information available at the time of the technical conference will also inform parties of the potential need for congestion relief. After the technical conference, interested parties will be afforded an opportunity to submit comments on the Trial Staff Report and Motion in these proceedings, and supplemental comments in the Public Policy Transmission Planning Process proceeding. The schedule also provides for replies to the comments submitted.

This schedule will allow the Commission to consider the Trial Staff Motion in August or September 2015, including determining which project(s) best meets the overall objectives of these proceedings such that they should continue in the Article VII process following our decision. The Commission recognizes the concerns raised in comments that the mere

[35] The Report and Motion should contribute towards a winnowing process to identify the most beneficial project or projects of the group, and provide Trial Staff's recommendations regarding whether transmission facilities are needed to address the identified congestion as compared to other non-transmission solutions that might be available as an alternative.

pendency of these proceedings may adversely affect property values and real estate transactions. By reducing the projects for consideration in as timely a manner as possible given the necessity of making an informed decision, the Commission intends to provide some level of certainty to the potentially affected communities and landowners.

Consideration of the Trial Staff Report and Motion will enable the Commission to consider whether to request the developers of any of the proposals submitted in the comparative process to propose their solution(s) to the NYISO for further evaluation.[36] In the event such request is made by the Commission, the costs incurred by a developer in preparing its proposed transmission solution would be recoverable under the NYISO tariff.[37] The Commission finds that allowing the recovery of these preparation costs would be reasonable under the circumstances because it encourages competition among the proposals that is ultimately more beneficial to ratepayers than the costs to be recovered, and therefore rejects the arguments to the contrary.

Following the comparative evaluation phase and the Commission's determination as to Public Policy Requirements, it is expected that if the Commission determines projects should proceed, the developer(s) of the preferred projects will pursue the completion of the Article VII process, while the NYISO completes its analysis required under the Public Policy Transmission Planning Process.[38] The Public Policy Transmission

[36] The results of those studies may also further inform the record in the certification proceedings.

[37] NYISO Open Access Transmission Tariff, Attachment Y, §31.4.3.2.

[38] Any projects that are ultimately selected by the NYISO as more efficient or cost-effective would require siting approvals from the Commission before they could be constructed.

Planning Process also provides an additional mechanism for studying generation and demand response alternatives to the AC transmission upgrades.[39]

In pursuing a comparative evaluation of projects to relieve congestion, the Commission is cognizant of other related proceedings. While many comments refer to the REV initiative, the Commission views this proceeding as complementary to the goals of REV. Achieving the objectives of the REV proceeding will not, at any time in the foreseeable future, eliminate the need for more robust and flexible transmission infrastructure linking the upstate regions to downstate through the Mohawk and Hudson Valleys. At the same time, improving the existing infrastructure will support some of the REV goals. It will allow for more efficient dispatch of bulk system resources to complement the activation of distribution-level resources, and it will facilitate the development of new renewable resources, such as wind, most of which will be sited upstate on the constrained side of the congested interfaces. The Commission therefore declines to hold these proceedings in abeyance until the completion of the REV initiative.

As requested by DEC, the Commission notes that the investigation of transmission solutions through a comparative evaluation process, and in the public policy planning process, is not the full equivalent to the statutory findings required under the PSL for granting an Article VII certificate. These investigations however will contribute to the record that informs the Commission in making the Article VII statutory findings for issuance of an Article VII certificate, which include, among other matters, the basis of the need for a

[39] NYISO Open Access Transmission Tariff, Attachment Y, §31.4.6.2.

particular facility and the degree of environmental compatibility.

The concept of environmental compatibility and public need requires the Commission to "protect environmental values, and take into account the total cost to society of such facilities."[40] The relevant considerations include, without limitation, the electric system requirements, the cost, the environmental impact, the availability and impact of alternatives, undergrounding considerations, conformance to long-range plans, State laws and local laws, and the public interest, convenience, and necessity. These Article VII findings can only be made after considering the totality of all relevant factors related to the environmental compatibility and public need for a particular facility.

The Commission finds that the comparative evaluation should proceed because there is sufficient evidence of significant constraints at the Central East and UPNY-SENY interfaces to support the decision to investigate possible transmission solutions, and because resolving that congestion could produce significant benefits for ratepayers. But the Commission has heard the concerns of the many parties that question the need for a transmission solution. As noted above, Commission is requiring that the need question be addressed beginning with a Trial Staff report and a technical conference. The parties remain free to develop arguments that alternative non-transmission congestion solutions rebut the need for designating the congestion relief as a Public Policy Requirement, or for the granting of an Article VII certification

[40] Chapter 272 of the Laws of 1970, Section 1, Legislative Findings.

to a proposed AC transmission project.[41] The Commission also invites those commentators who question whether any such solutions are necessary, to also participate and offer their views in Case 14-E-0454, as that proceeding is an appropriate

forum for comments[42] relating to the scope and significance of the Central East and UPNY/SENY congestion problem and to the necessity and effectiveness of a transmission solution.

Evaluation Criteria

As noted above, Trial Staff will be tasked with ranking the proposals. The ranking should take into account the six criteria identified in the Advisory Staff Recommendations, including: 1) the relative contribution to transfer capability; 2) the costs to ratepayers; 3) electric system impacts, emissions reductions, and impacts on production costs, measured in terms of overall changes to generation dispatch; 4) the extent of any additional right-of-ways that may be needed; 5) the integration of innovative technologies to enhance transfer capability or reduce the physical footprint of the project; and, 6) an initial assessment of environmental compatibility, including visual impacts. The four additional criteria proposed by the NYTOs are not adopted because they are largely redundant with the concept of electric system impacts and would remove focus from the key issue of increasing transfer capability in a manner that is cost efficient and environmentally compatible.

[41] In addition, the NYISO may be requested to evaluate alternative options to address the transmission needs. NYISO Open Access Transmission Tariff, Attachment Y, §31.4.2.1.

[42] Initial comments in that proceeding are due on December 29, 2014, but the schedule set forth in Appendix A attached to this order anticipates another round of comments at a later date.

The Commission declines to assign weights to the criteria at this time, as suggested by various parties. While each criterion should be given due consideration, Trial Staff will be given latitude in the first instance to look at the completeness, quality and verifiability of the information that is received and thereafter shall consider the feasibility of assigning weights to the criteria as part of its Report and Motion. Trial Staff, after reviewing the information received, will also devise what units of measurement will be used for the comparative evaluation in the first instance. The Commission appreciates the offer of Ag & Mkts to assist in the ranking, and expects Trial Staff will carefully consider any comments it receives from other State agencies and interested parties and explain its considerations for our review.

Regarding right-of-ways, the Commission clarifies that its objective is to encourage innovation and the use of existing rights-of-way so that the State experiences smart growth of the electric grid with the least impact to the environment and our communities. Therefore, the Commission desires, to the degree possible consistent with other policy objectives, to minimize the acquisition of additional lands for right-of-ways and the construction of major electric transmission facilities that are out of scale or character with existing facilities already in the landscape. While it is unfortunately impractical and would be unduly restrictive to impose an outright ban on all new right-of-way acquisition, the degree of necessity for such acquisition will be a key distinguishing factor affecting the viability of project proposals. The Commission recognizes that some additional private lands may be needed, but encourages developers to limit such requirements to the degree possible.

The NYTO’s TOTS projects have been withdrawn from these proceedings, so they will not be considered in the comparative evaluation process. The TOTS projects have already been accepted as part of the Indian Point Reliability Contingency Plan and their contribution toward the 1,000 MW target of congestion relief should be identified by Trial Staff and reflected in the baseline used to evaluate the incremental contribution of the remaining projects.

Regarding the NYISO's request for clarification as to the scope of the studies (i.e., the number of projects and studies for each project), the Commission recognizes that if too many variations are received, it may be necessary to limit each applicant to a single preferred proposal for full study purposes so as to not unreasonably delay the comparative evaluation process. The timing of the studies has been revised in the adopted schedule along with the insertion of intermediate milestones that reflect the need to obtain information from the powerflow analysis to use as modeling inputs in the analysis of production cost savings using General Electric's Multi-Area Production Simulation (GE MAPS). The Commission expects the NYISO to work cooperatively with DPS Staff and provide whatever assistance is necessary.

Cost Recovery and Cost Allocation

The comments are generally supportive of ensuring cost recovery through FERC-approved tariffs. Coordinating the comparative evaluation phase with the NYISO's public policy planning process would establish a mechanism for such cost recovery. The Commission adopts this approach.[43]

The Commission declines to address requests for an evaluation of ratepayer impacts by customer classifications

[43] This approach does not foreclose the possible consideration of an alternate method for cost recovery under State-approved mechanisms in the event recovery through FERC rates proves to be infeasible.

within each utility franchise, or to ensure cost allocation based on the contribution of each customer class to peak load, since these are matters best addressed in a ratemaking proceeding. Similarly, it is not appropriate to address at this time whether the period for cost recovery should extend over the projected service life of a project or a shorter period.

The Commission supports a "beneficiaries pay" approach for allocating costs, whereby those that derive the benefits of a project should bear the costs. Although a precise calculation of the projected benefits has not been completed, the cost allocation proposed in the Advisory Staff Recommendations is roughly commensurate with the anticipated beneficiaries. The Commission therefore adopts an approach whereby 75% of project costs are allocated to the economic beneficiaries of reduced congestion, while the other 25% of the costs are allocated to all customers on a load-ratio share. This would result in approximately 90% of the project costs being allocated to customers in the downstate region, and about 10% to upstate customers. This allocation reflects that the primary benefit of the projects will be reduced congestion into downstate load areas, but also recognizes that some benefits accrue to upstate customers in the form of increased reliability and reduced operational costs.

In the event the Commission designates Central East and UPNY/SENY congestion relief as a transmission need driven by a Public Policy Requirement under the NYISO's planning process, the Commission intends to prescribe the above-described cost allocation methodology in connection with such public policy determination. Parties that dispute they are beneficiaries, or that they are assigned a reasonable portion of the costs, would then be able to raise their objections before FERC.

The Commission notes that under the NYISO tariff, the NYISO would file with FERC any cost allocation prescribed under the Public Policy Requirement.[44] The NYISO tariff further provides that nothing therein "shall deprive a Transmission Owner or Other Developer of any rights it may have under Section 205 of the Federal Power Act to submit filings proposing any other cost allocation methodology to [FERC]…"[45] While the Commission does not take a position on the NYTOs' rights under the Federal Power Act, it appears the clarification requested by the NYTOs is already contained in this provision of the NYISO tariff.

Cost Estimates and Risk-sharing

Because the costs to ratepayers will be one of the criteria that Trial Staff will utilize in preparing its Report and Motion during the comparative evaluation process, the developers are expected to provide reliable and binding cost estimates or bids. All costs shall be stated in nominal (year of occurrence) dollars.

Upon considering the various requests to require additional information in the developer's cost estimates, the Commission adopts the following items, consistent with what would similarly be required to satisfy the provisions in the NYISO tariff.[46] In particular, each developer should provide credible capital cost estimates for its proposed project, with itemized supporting work sheets that identify all material and labor cost assumptions. The work sheets should include an estimated quantification of cost variance, providing an assumed plus/minus range around the capital cost estimate. Each

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[44] NYISO Open Access Transmission Tariff, Attachment Y, §31.5.5.4.1.

[45] Id.

[46] NYISO OATT, Attachment Y, §31.4.8.1.

developer should itemize: material and labor cost by equipment, engineering and design work, permitting, site acquisition, procurement and construction work, and commissioning needed for the proposed solution, all in accordance with Good Utility Practice.

For each of the above cost categories, the developer should specify the nature and estimated cost of all major project components, and estimate the cost of the work to be done at each substation and/or on each feeder to physically and electrically connect each facility to the existing system. The work sheets should itemize, to the extent applicable, all equipment for: (i) the proposed project, (ii) interconnection facilities (including Attachment Facilities and Direct Assignment Facilities), and (iii) System Upgrade Facilities, System Deliverability Upgrades, Network Upgrades, and Distribution Upgrades.

To help ensure the quality and comparability of the bids, and that ratepayers retain the benefit of this comparative evaluation process, the Commission finds that a risk-sharing mechanism is appropriate. The Commission anticipates that the successful developer or developers will seek cost recovery from FERC. Therefore, the Commission's policy approach to risk-sharing necessarily considers FERC policies and balances ratepayer interests with a developer’s expectation that it will earn a regulated rate-of-return on an approved transmission project.

The Commission believes a transmission developer who intends to seek regulated rates should be incented to produce accurate cost estimates in the Article VII process, and then to meet them, particularly since cost is one of the criteria by which projects will be selected or rejected. The developer should be entitled to a reasonable base rate-of-return up to the amount of its estimates, but should not receive compensation at the same level for the actual costs that exceed those estimates. The Advisory Staff recommendation, which recognizes this principle, is a reasonable approach for risk-sharing and is therefore adopted. Accordingly, if actual costs come in above a bid, the developer should bear 20% of the cost over-runs, while ratepayers should bear 80% of those costs. If actual costs come in below a bid, then the developer should retain 20% of the savings. Furthermore, if the developer seeks incentives from FERC above the base return-on-equity otherwise approved by FERC, then the developer should not receive any incentives above the base return-on-equity on any cost overruns over the bid price. The bid price would therefore cap the costs that may be proposed to FERC for incentives. The Commission believes this approach to be consistent with FERC policies and reflects FERC's underlying objectives of balancing customer and utility interests, and FERC's policies encouraging innovative risk and reward sharing arrangements.

Regarding comments that suggest a risk-sharing approach is inconsistent with FERC policies and should be modified to ensure consistency (i.e., to allow cost over-runs and full recovery of prudently incurred investment), the Commission notes that FERC has accepted "specific, binding cost control measures that the transmission developer agrees to accept, including any binding agreement by the transmission developer and its team to accept a cost cap that would preclude project costs above the cap from being recovered...."[47] The Commission finds that the risk-sharing approach proposed in the Advisory Staff Recommendations is reasonable and appropriate,

[47] Docket Nos. ER13-103-000 et al., California Independent System Operator Corporation, Order on Compliance Filing (issued April 18, 2013), 143 FERC ¶61,057, ¶233.

and is generally consistent with FERC precedent. Accordingly, the Commission will expect any developer submitting a project for consideration in the comparative evaluation process to be willing to accept the risk-sharing proposal adopted herein. The Commission expects this approach will ultimately be subject to FERC's approval.

The Commission also acknowledges that a developer may incur additional, identifiable, and verifiable costs necessary to comply with Commission-imposed modifications and mandates that could not have been reasonably anticipated in formulating the initial bid price. These additional qualifying costs would need to exceed a materiality threshold of 5% above the initial bid price to be recoverable. To encourage further creativity, developers will be allowed to propose alternative risk-sharing proposals if they are submitted in addition to the developer's bid prepared on the above-described partial pass-through model. Developers are also free to propose methods to index their bid prices to changes in the cost of key elements so long as the indexes chosen are governmental in origin and not subject to influence or manipulation by developers.

## CONCLUSION

As discussed above, the Commission adopts a comparative evaluation process and expanded procedural schedule contained in Appendix A. The Commission also adopts the Advisory Staff Recommendations with respect to cost recovery, cost allocation, and risk-sharing. Any developer that may be selected should file with FERC the cost allocation and risk-sharing methodologies we adopt herein. In the event we designate the congestion relief being investigated in these proceedings as a Public Policy Requirement under the NYISO's planning process and our Policy Statement, the Commission expects that the NYISO will file these methodologies with FERC on behalf of any selected developer(s).

The Commission orders:

1. The Commission adopts the cost allocation and risk-sharing mechanisms, and cost recovery approach, as discussed in the body of this order.

2. The Commission adopts the procedural processes and schedule set forth in Appendix A. North America Transmission, LLC and North America Transmission Corporation (NAT), the New York Transmission Owners (NYTOs); NextEra Energy Resources, LLC (NextEra) and, Boundless Energy NE, LLC (Boundless) shall file with the Secretary in the application-specific docket to which the filing pertains (Cases 13-T-0454, 13-T-0455, 13-T-0456, 13-M-0457 and 13-T-0461), the information identified in Appendices B and C by January 7, 2015, and the information identified in Appendix D by January 19, 2015. Any information filed in any one of these cases shall be part of the common-record of all of these cases as well as of Cases 12-T-0502 and 13-E-0488. NAT, NextEra and Boundless shall file with the Secretary on or before February 27, 2015, in the application-specific docket to which the filing pertains, a notice that a System Reliability Impact Study (SRIS) was in progress pursuant to the tariff requirements of the New York Independent System Operator, Inc. (NYISO).

3. Trial Staff shall be designated prior to the January 7, 2015 deadline set forth above.

4. The Secretary, in sole discretion, may extend the deadlines set forth in this order relating to the AC Transmission Process. Any request for an extension must be in writing, include a justification for the extension, and be filed at least one day prior to any affected deadline. The deadlines in Appendix A for the "NYISO PPR Process" are merely anticipated

at this time and will be subject to further notification in that proceeding.

5. All intervenor funding matters shall be addressed directly to the Administrative Law Judges.

6. These proceedings are continued.

By the Commission,

(SIGNED) KATHLEEN H. BURGESS
Secretary

APPENDIX A

Table of Milestones and Deadlines

| **AC Transmission Process** | | **NYISO PPR Process** | |
|---|---|---|---|
| **Milestone** | **Deadline** | **Milestone** | **Deadline** |
| | | NYISO Receives Public Policy Requirements Proposals | September 30, 2014 |
| | | NYISO Submits any Proposed Public Policy Requirements to the Commission | October 3, 2014 |
| | | SAPA Notice Published in State Register | November 12, 2014 |
| Commission Decision on Advisory Staff Process Proposal | December 2014 Session* | | |
| Deadline for Applicants to Submit Part A Data Required for NYISO Analysis at Request of DPS | January 7, 2015 | | |
| | | Deadline for SAPA Comments | December 29, 2014 |
| Deadline for Applicants to Submit Remainder of Part A Proposals Offered for Comparative Evaluation | January 19, 2015 | | |
| Deadline for Applicants to give notice that their SRIS is underway | February 27, 2015 | | |
| Deadline for Parties to Submit Written Comments on the Part A Submittals | March 4, 2015 | | |
| Deadline for Replies | March 19, 2015 | | |
| Part A MAPS Inputs Completed | April 15, 2015 | | |
| Part A Power Flow Analyses Completed | May 13, 2015 | | |

* Note: The date for any action intended to occur at a Commission Session is to be established at the discretion of the Chair.

Table of Milestones and Deadlines
(Continued)

| AC Transmission Process | | NYISO PPR Process | |
|---|---|---|---|
| **Milestone** | **Deadline** | **Milestone** | **Deadline** |
| Part A MAPS Runs Completed | May 20, 2015 | | |
| Deadline for DPS Trial Staff Report and Motion | June 10, 2015 | | |
| Technical Conference | June 17-18, 2015 | Technical Conference | June 17-18, 2015 |
| Deadline for Responses to DPS Trial Staff Report and Motion | July 15, 2015 | Deadline for Supplemental Comments on Proposed Public Policy Requirements | July 15, 2015 |
| Deadline for Replies | July 30, 2015 | Deadline for Replies | July 30, 2015 |
| Commission Decision on DPS Motion | August or September 2015 Session* | Commission Decision on Public Policy Requirements; Commission Requests Winning Developers to Propose Transmission Solutions | August or September 2015 Session* |
| Comparative Phase Ends; Individual Article VII Cases Resume; Part B Scoping Process Commences | September 2015 | NYISO Solicits Transmission Solutions | September 2015 |
| | | NYISO Receives Transmission Solutions Proposals | November 2015 |
| Part B Applications Submitted | To Be Determined by ALJs | NYISO Begins Review of Solutions | To Be Determined by NYISO |

* Note: The date for any action intended to occur at a Commission Session is to be established at the discretion of the Chair.

APPENDIX B

Part A Data to be filed by Applicants on January 7, 2015

(1) Modeling data that has been identified (see Appendix C).

(2) Provide the information identified in the New York Independent System Operators Open Access Transmission Tariff Attachment Y Sections 31.4.4.1 Developer Qualification and Timing and 31.4.5.1 Project Information Requirements, as follows:

**31.4.4.1 Developer Qualification and Timing**

The ISO shall provide each Developer with an opportunity to demonstrate that it has or can draw upon the financial resources, technical expertise, and experience needed to develop, construct, operate, and maintain a transmission solution to a Public Policy Transmission Need. The ISO shall consider the qualification of each Developer in an evenhanded and non-discriminatory manner, treating Transmission Owners and Other Developers alike.

The ISO shall make a determination on the qualification of a Developer to propose to develop a transmission project as a transmission solution to a Public Policy Transmission Need based on the following criteria:

31.4.4.1.1 The technical and engineering qualifications and experience of the Developer relevant to the development, construction, operation and maintenance of a transmission facility, including evidence of the Developer's demonstrated capability to adhere to standardized construction, maintenance, and operating practices and to contract with third parties to develop, construct, maintain, and/or operate transmission facilities;

31.4.4.1.2 The current and expected capabilities of the Developer to finance, develop and construct a transmission facility and to operate and maintain it for the life of the facility. For purposes of this criteria, the Developer shall provide the ISO a description of transmission facilities (not to exceed ten) that the Developer has previously developed, constructed, maintained or operated and the status of those facilities, including whether the construction was completed, whether the facility entered into commercial operations, whether the facility has been suspended or terminated for any reason, and evidence demonstrating the ability of the Developer to address and timely remedy any operational failure of the facilities; and

31.4.4.1.3 The Developer's current and expected capability to finance, or its experience in arranging financing for, transmission facilities. For purposes of the ISO's determination, the Developer shall provide the ISO:

(1) evidence of its demonstrated experience financing or arranging financing for transmission facilities, including a description of such projects (not to exceed ten) over the previous ten years, the capital costs and financial structure of such projects, a description of any financing obtained for these projects through rates approved by the Commission or a state regulatory agency, the financing closing date of such projects, and whether any of the projects are in default;

(2) its audited annual financial statements from the most recent three years and its most recent quarterly financial statement or equivalent information, if available;

(3) its credit rating from Moody's Investor Services, Standard & Poor's, or Fitch or equivalent information, if available;

(4) a description of any prior bankruptcy declarations, material defaults, dissolution, merger or acquisition by the Developer or its predecessors or subsidiaries occurring within the previous five years; and

(5) such other evidence that demonstrates its current and expected capability to finance a project to solve a Public Policy Transmission Need.

Any Developer seeking to be qualified may submit the required information, or update any previously submitted information, at any time. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any non-public financial qualification information that is submitted to the ISO by the Developer under Section 31.4.4.1.3 and is designated by the Developer as "Confidential Information." The ISO shall within 15 days of a Developer's submittal, notify the Developer if the information is incomplete. If the submittal is deemed incomplete, the Developer shall submit the additional information within 30 days of the ISO's request. The ISO shall notify the Developer of its qualification status within 30 days of receiving all necessary information. A Developer shall retain its qualification status for a three-year period following the notification date; provided, however, that the ISO may revoke this status if it determines that there has been a material change in the Developer's qualifications and the Developer no longer meets the qualification requirements. A Developer that has been qualified shall inform the ISO within thirty days of any material change to the information it provided regarding its qualifications and shall submit to the ISO each year its most recent audited annual financial statement when available. At the conclusion of the three-year period or following the ISO's revocation of a Developer's qualification status, the Developer may re-apply for a qualification status under this section.

Any Developer determined by the ISO to be qualified under this section shall be eligible to propose a regulated transmission project as a transmission solution to a Public Policy Transmission Need and shall be eligible to use the cost allocation and cost recovery mechanism for regulated transmission projects set forth in Section 31.5 of this Attachment Y and the appropriate rate schedule for any approved project.

**31.4.5.1 Project Information Requirements**

Any Developer seeking to offer a transmission solution for Public Policy Transmission Needs must provide, at a minimum, the following details: (1) contact information; (2) the lead time necessary to complete the project, including, if available, the construction windows in which the Developer can perform construction and what, if any, outages may be required during these periods; (3) a description of the project, including type, size, and geographic and electrical location, as well as planning and engineering specifications as appropriate; (4) evidence of a commercially viable technology; (5) a major milestone schedule; (6) a schedule for obtaining any required permits and other certifications; (7) a demonstration of Site Control or a schedule for obtaining such control; (8) status of any contracts (other than an Interconnection Agreement) that are under negotiations or in place; (9) status of ISO interconnection studies and interconnection agreement; (10) status of equipment availability and procurement; (11) evidence of financing or ability to finance the project; (12) capital cost estimates for the project; (13) a description of permitting or other risks facing the project at the stage of project development, including evidence of the reasonableness of project cost estimates all based on the information available at the time of the submission; and (14) any other information requested by the ISO.

A Developer shall submit the following information to indicate the status of any contracts: (i) copies of all final contracts the ISO determines are relevant to its consideration, or (ii) where one or more contracts are pending, a timeline on the status of discussions and negotiations with the relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any contract that is submitted to the ISO and is designated by the Developer as "Confidential Information."

A Developer shall submit the following information to indicate the status of any required permits: (i) copies of all final permits received that the ISO determines are relevant to its consideration, or (ii) where one or more permits are pending, the completed permit application(s) with information on what additional actions must be taken to meet the permit requirements and a timeline providing the expected timing for finalization and receipt of the final permit(s). The final permits shall be submitted to the ISO when available.

A Developer shall submit the following information, as appropriate, to indicate evidence of financing by it or any Affiliate upon which it is relying for financing: (i) evidence of self-financing or project financing through approved rates or the ability to do so, (ii) copies of all loan commitment letter(s) and signed financing contract(s), or (iii) where such financing is pending, the status of the application for any relevant financing, including a timeline providing the status of discussions and negotiations of relevant documents and when the negotiations are expected to be completed. The final contracts or approved rates shall be submitted to the ISO when available.

Failure to provide any data requested by the ISO within the timeframe provided in Section 31.4.4.3 of this Attachment Y will result in the rejection of the proposed solution from further consideration during that planning cycle.

APPENDIX C

## IDENTIFIED DATA REQUIRED FOR POWERFLOW MODELING

(To be filed by Applicants on January 7, 2015)

The following data is required to model each portfolio. Additional data may be requested as necessary to accurately model the proposed projects.

**AC Transmission**

For each new or modified circuit, provide:

- From Bus, To Bus: Substations at which the circuit terminates
- Base kV: Nominal operating voltage in kV
- R, X: Line impedance in per unit on 100 MVA system base
- B: Total line charging susceptance in per unit on 100 MVA system base
- Normal rating: Summer peak 24 hour thermal rating in MVA
- LTE rating: Summer peak 4 hour long term emergency thermal rating in MVA
- STE rating: Summer peak 15 minute short term emergency thermal rating in MVA
- Common tower: Identify all other circuits that will share common towers with the circuit

**Series Compensation**

For each new series capacitor, provide:

- Circuit: Identify circuit to be compensated
- Location: Specify location of series compensation (e.g., which end of the circuit)
- X: Percentage compensation of the line
- Normal rating: Summer peak 24 hour thermal rating in MVA
- LTE rating: Summer peak 4 hour long term emergency thermal rating in MVA
- STE rating: Summer peak 15 minute short term emergency thermal rating in MVA

**Transformers**

For each new or modified transformer, provide:

- From Bus, To Bus: Substations at which the transformer terminates
- Voltage ratio: Nominal operating high side and low side voltages in kV
- R, X: Transformer impedance in per unit on 100 MVA system base
- Control Type: Fixed tap or voltage control
- Fixed Taps: Tap positions available

* Vmax, Vmin: Upper and lower voltage limits at the controlled bus
* Normal rating: Summer peak 24 hour thermal rating in MVA
* LTE rating: Summer peak 4 hour long term emergency thermal rating in MVA
* STE rating: Summer peak 15 minute short term emergency thermal rating in MVA

**Substations**

For each new substation, provide a breaker diagram depicting the connection of each element to the substation and corresponding breaker locations.

For each modified substation (e.g., new line connecting to existing substation) provide a breaker diagram depicting the connection of each element to the substation and corresponding breaker locations, OR provide a detailed description as to the modifications to the substation. Specifically identify other circuits in breaker positions adjacent to new or modified circuits.

APPENDIX D

Part A Materials to be filed by Applicants on January 19, 2015
(Remainder of proposals offered for comparative evaluation)

Part A Article VII application must include:

a. Payment for Intervenor Fund (85-2.4):
b. Application content (85-2.8(a), (b), (d) and (f)):
    i. Proposed Facility (85-2.8)
        1. a description of the proposed facility,
        2. location of proposed facility or right-of-way,
        3. explanation of need for the proposed facility, and
    ii. such other information as the applicant deems necessary or desirable.
c. Notice of Application, newspaper publication and proof of service (85-2.10)
d. General requirements for each exhibit (86.1)
e. Exhibit 1: General Information Regarding Application (86.2): Two additional requirements:
    i. applicant must include an e-mail address with applicant's contact information.
    ii. corporate applicant must identify whether it is incorporated under the Transportation Corporation Law.
f. Exhibit 2: Location of Facilities (86.3)(a)(1): Detailed maps, drawings and explanations showing the ROW,[1] including GIS shapefiles of facility locations and:
    i. NYSDOT 1:24,000 topographic edition showing:
        1. proposed ROW (indicating control points) covering an area of at least 5 miles on either side of the proposed centerline.
        2. Cross Sections of typical ROW depicting location and configuration of proposed and all existing overhead and underground facilities with typical design detail including height of structures and configuration of circuits for overhead facilities and diameter of pipe or conduit for underground facilities. geologic, historic resources listed on the state or national register of historic places, or scenic area, park, or wilderness within three miles on either side of the proposed

[1] Aerial photo requirement (86.3(b)) shifts to Part B as long as applicant uses 2010 or newer USGS topo for 1:24,000 mapping required by 86.3(a)(1).

centerline for an overhead facility; or within one mile of the proposed centerline for an underground or sub-aquatic segment.

ii. (86.3)(a)(2) – NYSDOT 1:250,000 scale or other recent edition topographic maps showing the relationship of the proposed facility to the applicant's overall system, with respect to:
1. the location, length and capacity of the proposed facility, and of any existing appurtenances related to the proposed facility.
2. the location and function of any structure to be built on, or adjacent to, the right-of-way (including switchyards; substations; series compensation station facilities; microwave towers or other major system communications facilities; etc.)
3. the location and designation of each point of connection between an existing and proposed facility, and
4. nearby, crossing or connecting rights-of-way or facilities of other utilities.

g. Exhibit 5: Design Drawings (86.6(a) and (b)): design, profile and architectural drawings and descriptions of proposed facility, including:
  i. the length, width and height of any structure, and
  ii. the material of construction, color and finish

h. Exhibit 7: Local Ordinances (86.8(4)):[2] Recent edition 1:24,000 topos with overlays showing:
  i. zoning; and
  ii. flood zones (include 100 year (1%) and 500 year (0.2%) flood hazard areas, and floodway locations, as available)

i. Exhibit E-1: Description of Proposed Transmission Line (88.1(a)-(d)): detailed description of proposed line, including:
  i. design voltage and voltage of initial operation
  ii. type, size, number and materials of conductors
  iii. insulator design
  iv. length of the transmission line

[2] Applicants are encouraged to show zoning districts as overlays on 1:24,000 scale topo maps, but may use other appropriate mapping that clearly relates the proposed facilities locations to zoning district maps.

j. Exhibit E-4: Engineering Justification (88.4)and new section of 85-2.8 addressing compatibility of the facility with the goals and benefits to New York's ratepayers identified in the Blueprint:
    i. summary of engineering justification for proposed line, showing its relation to applicant's existing facilities and the interconnected network, with full justification to be submitted in Part B;
    ii. summary of anticipated benefits with respect to reliability and economy to applicant and interconnected network. Specific benefits to be submitted in Part B;
    iii. proposed completion date, and impact on applicant's systems and of others' of failure to complete on such date;
    iv. appropriate system studies (see SIS notice requirement below);
    v. a general demonstration of how, and to what extent, the proposed transmission project meets the congestion relief, system reliability, reduction in regional air pollution and greenhouse gas emissions and the other benefits and objectives identified by the Commission in Case 12-T-0502; details of this demonstration shall be provided with Part B filing, along with the results of the NYISO studies required by 16 NYCRR 88.4 (a)(4);

k. Pre-Filed direct testimony of applicant's witnesses supporting Part A exhibits

2. Factual evidence showing how the project utilizes existing ROW and what additional land rights will need to be acquired.

3. Information on the use of any advanced technologies that are proposed to apply to facility design, construction or operations.

4. Notice that the SIS/SRIS studies are in progress (study scope accepted and work underway pursuant to a Study Agreement with the NYISO); and

5. Scoping statement and schedule: Describing how and when the applicant will produce the exhibits required for the Part B filing:

i. Exhibit 3 (86.4): Alternatives: applicant may use recent edition topographic maps (1:24,000). If any alternative is sub aquatic, applicant should use recent edition nautical charts to show any alternative route considered.(86.4)

ii. Exhibit 4 (86.5): Environmental Impact must include: assessment of impacts on ecological, land use, cultural and visual resources; noise analysis; coastal zone consistency (including local waterfront revitalization programs and designated inland waterway areas); efforts, if any, to minimize the emissions of greenhouse gases during the construction, operation and maintenance of the proposed facility; plans to ensure facility resilience to rising water tables, flooding, ice storms, coastal storm surges, and extreme heat.

iii. Exhibit 6 (86.7): Economic Effects of Proposed Facility

iv. Exhibit 7(86.8 (1),(3),(5) and (6): Local Ordinances where Facility modifications being made, including statement of consultations with municipalities and local agencies, summary table of all substantive requirements, zoning designation or classification, and list of regulatory approvals.

v. Exhibit 8(86.9): Other Pending Filings

vi. Exhibit 9(86.10): Cost of Proposed Facility modifications.

vii. Exhibit E-1 (88.1(e)(f)): Facility Description

viii. Exhibit E-2 (88.2): Other Facilities

ix. Exhibit E-3 (88.3): Underground Construction

x. Exhibit E-5 (88.5): Effect on Communications

xi. Exhibit E-6 (88.6): Effect on Transportation

a. Notice of Application and proof of notice and service (85-2.10)

**Part A Initial Applications for projects that are not subject to Article VII must include:**

1. Links to the full text and figures of all applications submitted to any state, local or federal agency related to the proposed project.
2. A list of the permits and approvals that the project sponsor is required to obtain for the construction and operation of the project, and a schedule for the submission of any applications or other filings not provided under item 1.
3. Where a lead agency has been identified and has made a determination of significance pursuant to SEQRA, a copy of the lead agency's determination.
4. A copy of the EAF reviewed by the lead agency in making its determination, or, if a determination has not been made, a copy of the Part 1 EAF submitted to the involved agency or agencies.
5. If the lead agency's determination of significance was positive, a schedule for the preparation and submission of a DEIS or a copy of the DEIS submitted to the lead agency.
6. If an applicant has yet to receive the lead agency's determination, a description of the status of the SEQRA review (including a proposed schedule for preparation and submission of a DEIS, assuming the determination will be positive).
7. A demonstration of how and to what extent the proposed project meets the congestion relief objectives identified by the PSC in Case 12-T-0502.
8. Factual evidence showing how the project utilizes existing ROW and what additional land rights they will need to acquire.
9. Information on the use of any advanced technologies that they propose to apply.

**Additional information to be included in the Part A Materials to be filed by Applicants on January 19, 2015 (as a result of comments received):**

Provide tables and summary information, and narrative description of facility impacts and compatibility with existing environmental conditions and land uses in the various project locations. Tables should address project total as well as segments individually (e.g., individual terminal facilities, and transmission line right-of-way from substation to substation).

Land Cover and Land Use

Land Cover Type Categories – Provide a table listing standard classifications (USGS NLCD 2011 mapping) and identify by classification the distance crossed, acres of areas included (a) in affected ROW and (b) within 500 feet of ROW limits.

Land Use Categories – Provide a table listing real property classifications codes based on NYS ORPS Land Use Classifications, identify by classification the distance crossed in miles, acres of areas included (a) in affected ROW and (b) within 500 feet of ROW limits.

Agricultural Lands – Provide a table indicating ROW Distance, area, acres of disturbance as either permanent or temporary impacts (include facility footprint for: transmission structures (indicating temporary and permanent installations); associated facilities (substations, etc. ); access roads; staging or laydown areas; identify impacted lands using criteria above for the following categories:

Agricultural Lands crossed – identify specific categories including:

Use categories: croplands, haylands, pasture lands, reserve lands;

Agricultural Districts: including 'use categories' above and Farm Woodlands;

Orchards and Vineyards;

'Sugar Bush' woodland (managed for maple syrup production); and

Prime Soils; Soils of Statewide Significance.

Residential Areas – Provide a table listing by Towns crossed (and Cities or Villages as appropriate) the number of existing residences within 500 feet of the proposed facility by distance zones: 1 to 100 feet; 101 to 250 feet; 251 to 500 feet. Specify the location, number and type of any buildings and structures (residences, barns, garages, swimming pools) that may need to be acquired to accommodate facility construction and operation.

Population Densities: provide mapping of project location showing population density by municipality, using US Census Bureau, Census 2010 Demographic Profile Data.

Natural and Ecosystem Resources

Wetlands – Identify potential impact areas for facility footprints including structures and access roads for total mapped wetlands areas (using NYSDEC mapping for NYS-regulated wetlands; and USDI-NWI for federally identified wetlands; supplemented by ground survey information or remote-sensing techniques as applicable); provide tables listing individual wetlands distances crossed by facility ROW in feet; and total in miles; ROW in wetland area crossed in acres; anticipated number of structures within wetlands (based on site survey or typical design criteria based on structure type, height and span lengths anticipated); expected areas of wetland cover type conversions, specifying temporary and permanent impacts (e.g. wetland forest clearing and conversion to scrub-shrub or emergent marsh, etc.); and a characterization of probable impacts to significant wetlands benefits.

Rivers and streams: Provide a table identifying NYS Water Quality classification, number and distance crossed for river and stream crossings; number, length and acreage of proposed access road construction or improvements within river and streams crossed (bed and banks disturbance); provide a narrative discussion and tabular summary of cumulative effects on watershed areas for stream impacts within a common watershed.

Significant Coastal Habitats & Significant Natural Ecological Communities: Provide a table listing NYS DOS Significant Coastal Habitats and NYS DEC Significant Natural Ecological Communities within proposed facility ROW limits, indicating the distance of crossing; an estimate of the extent of disturbance anticipated due to facility construction including acres of clearing, length and acreage of access road improvements, number of transmission structures to be installed, and extent of excavation within the communities, if any.

Rare, Threatened or Endangered Species Habitats: Provide a table identifying and listing RT&E species locations and habitats for listed State and Federal Plants and Animals potentially crossed by or affected by transmission facilities and associated access roads and related facilities; indicate the distance of crossing; an estimate of the extent of disturbance anticipated due to facility construction including acres of clearing, length and acreage of access road improvements, number of transmission structures to be installed, and extent of excavation within the habitats, if any. Provide a confidential report addressing the nature of locations and habitats identified, potential impacts to RT&E species, feasible mitigation measures and the nature of probable impacts and avoidance strategies and mitigation measures.

Cultural Resources

For each designated or pre-determined eligible NRHP historic property and district in the project area, indicate:

(a) the distance and acreage directly crossed by the proposed facility ROW or permanent associated facilities (separately addressing any permanent or temporary access roads);

(b) distance to historic properties and districts not directly crossed by the facilities; and

(c) potential for visibility from the resource to the facilities.

Provide assessment of project visual impact on NRHP listed and eligible properties as per the Visual Assessment criteria below.

Visual Resources

Identify Visual resources within 3 miles study area; provide map of preliminary viewshed area based on assumed structure heights and screening by vegetation (specifying assumptions and applicable criteria); for facility locations within 5 miles of Dept. of State designated Scenic Areas of Statewide Significance (SASS), extend study area to 5 miles; list number of visual resources by category within projected areas of project visibility; and assess the degree of project visibility and probable extent of visual contrast change from existing conditions based on classes listed below. Provide narrative assessment of visual contrast including rating of photosimulation depictions of facility appearance from representative visual receptor locations. Describe mitigation measures appropriate to minimize adverse visual impacts.

Areas in Visibility classes:

A. no change in extent of visibility – new structures at same height as existing or shorter than existing;
B. minor change - structures height increase by 10 feet or less;
C. structure height increase by more than 10 feet.

Areas in Qualitative Change classes:

A. no significant change in structure design (e.g., re-conductoring; lattice tower replaced by similar lattice tower);
B. structure change potentially significant (e.g. lattice replaced by monopoles with other lattice facilities remaining on ROW).

Sound Environment and Noise Assessment

For projects proposing the upgrade of existing or construction of new terminal or associated facilities such as substations, provide a preliminary assessment of the existing sound environment identifying the characteristics of the facility area and surrounding setting, distances from noise sources to surrounding critical noise sensitive receptors and site boundary lines. Report existing daytime and nighttime residual ambient (L90) sound levels based on field noise surveys performed during a representative period of time in line with applicable and relevant ANSI standards. Indicate potential for noise producing equipment (transformers, reactors, emergency generators, etc.) to increase existing residual ambient sound levels; and specify design goals and criteria for minimizing adverse environmental noise impacts on identified noise sensitive receptor locations (residences, property lines, public use areas, etc.). Provide a preliminary assessment of potential annoyance or community noise response associated with design goals and/or expected noise levels including the effect of any prominent tones as well as any limitations on future use of adjacent properties caused by noise emissions. Identify any local laws, noise ordinances or regulations applicable to noise levels due to operation or construction of the proposed terminal or associated facilities.

Storm Resiliency & Climate Change

Provide a table identifying the number and distance of river and stream flood hazard areas crossed (specify Floodways, Flood Hazard Zone A through E, etc.); and estimated number of permanent structures within river or stream flood hazard areas (specify estimates for transmission facility structures, access roads, culverts, and fill areas).

Provide a narrative description for each major flood hazard area (e.g., Mohawk River – Erie Barge Canal; Hudson River; Susquehanna River; Schoharie Creek) crossed by proposed facility, indicating characteristics of setting and proposed facility design measures to avoid or minimize potential impacts on facility reliability due to flooding and severe storm events.

| | Company | CIQ ID | Moody's Rating | S&P Rating | Dividend Paying? | Not in M&A Activity? | Proxy Group |
|---|---|---|---|---|---|---|---|
| 1 | ALLETE, Inc. | IQ289272 | A3 | BBB+ | Yes | Yes | selected |
| 2 | Alliant Energy Corp. | IQ312949 | A3 | A- | Yes | Yes | selected |
| 3 | Ameren Corp. | IQ373264 | Baa2 | BBB+ | Yes | Yes | selected |
| 4 | American Electric Power Co. Inc. | IQ135470 | Baa1 | BBB | Yes | Yes | selected |
| 5 | Avista Corp. | NYSE:AVA | Baa1 | BBB | Yes | Yes | selected |
| 6 | Black Hills Corp. | IQ255902 | Baa1 | BBB | Yes | Yes | selected |
| 7 | CenterPoint Energy Inc. | IQ279513 | Baa1 | A- | Yes | Yes | selected |
| 8 | Cleco Corp. | IQ259829 | Baa2 | BBB+ | Yes | No | |
| 9 | CMS Energy Corp. | IQ257682 | Baa2 | BBB+ | Yes | Yes | selected |
| 10 | Consolidated Edison Inc. | IQ263295 | A3 | A- | Yes | Yes | selected |
| 11 | Dominion Resources, Inc. | IQ267105 | Baa2 | A- | Yes | Yes | selected |
| 12 | DTE Energy Co. | IQ266598 | A3 | BBB+ | Yes | Yes | selected |
| 13 | Duke Energy Corp. | IQ267850 | A3 | BBB+ | Yes | Yes | selected |
| 14 | Edison International | IQ301891 | A3 | BBB+ | Yes | Yes | selected |
| 15 | El Paso Electric Co. | IQ268503 | Baa1 | BBB | Yes | Yes | selected |
| 16 | Empire District Electric Co. | IQ269306 | Baa1 | BBB | Yes | Yes | selected |
| 17 | Entergy Corp. | IQ269764 | Baa3 | BBB | Yes | Yes | selected |
| 18 | Exelon Corp. | IQ296181 | Baa2 | BBB | Yes | No | |
| 19 | FirstEnergy Corp. | IQ293515 | Baa3 | BBB- | Yes | Yes | selected |
| 20 | Great Plains Energy Inc. | IQ282981 | Baa2 | BBB+ | Yes | Yes | selected |
| 21 | Hawaiian Electric Industries Inc. | IQ277854 | Baa2 | BBB- | Yes | No | |
| 22 | IDACORP Inc. | IQ280458 | Baa1 | BBB | Yes | Yes | selected |
| 23 | Integrys Energy Group Inc. | IQ315149 | A3 | A- | Yes | Yes | selected |
| 24 | ITC Holdings Corp. | IQ6565801 | Baa2 | A- | Yes | Yes | selected |
| 25 | MGE Energy, Inc | MGEE | NR | NR | Yes | Yes | |
| 26 | NextEra Energy, Inc. | IQ270586 | Baa1 | A- | Yes | Yes | selected |
| 27 | Northeast Utilities | IQ292525 | Baa1 | A- | Yes | Yes | selected |
| 28 | Northwestern Corporation | IQ184841 | A3 | BBB | Yes | Yes | selected |
| 29 | OGE Energy Corp. | IQ293569 | A3 | A- | Yes | Yes | selected |
| 30 | Otter Tail Corp. | IQ294269 | Baa2 | BBB | Yes | Yes | selected |
| 31 | Pepco Holdings Inc. | IQ297660 | Baa3 | BBB+ | Yes | No | |
| 32 | PG&E Corp. | NYSE:PCG | Baa1 | BBB | Yes | Yes | selected |
| 33 | Pinnacle West Capital Corp. | IQ296957 | Baa1 | A- | Yes | Yes | selected |
| 34 | PNM Resources Inc. | IQ298441 | Baa3 | BBB | Yes | Yes | selected |
| 35 | Portland General Electric Co. | IQ297526 | A3 | BBB | Yes | Yes | selected |
| 36 | PPL Corp. | IQ185508 | Baa3 | BBB | Yes | Yes | selected |
| 37 | Public Service Enterprise Group Inc. | IQ298482 | Baa2 | BBB+ | Yes | Yes | selected |
| 38 | SCANA Corp. | IQ188244 | Baa3 | BBB+ | Yes | Yes | selected |
| 39 | Sempra Energy | IQ120622 | Baa1 | BBB+ | Yes | Yes | selected |
| 40 | Southern Co. (The) | IQ120623 | Baa1 | A | Yes | Yes | selected |
| 41 | TECO Energy Inc. | IQ306596 | Baa1 | BBB+ | Yes | Yes | selected |
| 42 | UIL Holdings Corp. | IQ310736 | Baa2 | BBB | Yes | Yes | selected |
| 43 | Unitil Corp. (UTL) | NYSE:UTL | NR | BBB | Yes | Yes | |
| 44 | Vectren Corp. | IQ411206 | A3 | A- | Yes | Yes | selected |
| 45 | Westar Energy Inc. | IQ283024 | Baa1 | BBB+ | Yes | Yes | selected |
| 46 | Wisconsin Energy Corp. | IQ315117 | A2 | A- | Yes | Yes | selected |
| 47 | Xcel Energy Inc. | IQ527542 | A3 | A- | Yes | Yes | selected |
| | **Total Selected** | | | | | | **41** |

## Staff Proxy Group Stock Prices & Dividend
### 6 Month Average Price Data

| | Company | 2014 Annual Dividend (Value Line) | Annual Dividend | Six-month Average Price | Jul-14 | | Aug-14 | | Sep-14 | | Oct-14 | | Nov-14 | | Dec-14 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | High | Low | High | Low | High | Low | High | Low | High | Low | High | Low |
| 1 | ALLETE, Inc. | 1.96 | 3.95% | $49.56 | 51.56 | 46.90 | 48.80 | 46.14 | 48.82 | 44.39 | 52.68 | 44.19 | 53.26 | 49.56 | 57.97 | 50.49 |
| 2 | Alliant Energy Corp. | 2.04 | 3.40% | $59.96 | 60.89 | 56.50 | 58.51 | 55.04 | 59.36 | 54.69 | 62.30 | 55.38 | 63.73 | 61.35 | 69.78 | 61.94 |
| 3 | Ameren Corp. | 1.61 | 3.93% | $40.94 | 40.96 | 38.44 | 39.99 | 36.65 | 40.31 | 37.53 | 42.71 | 38.25 | 44.22 | 41.89 | 48.14 | 42.15 |
| 4 | American Electric Power Co. Inc. | 2.03 | 3.68% | $55.22 | 55.91 | 51.96 | 53.71 | 49.06 | 53.88 | 51.58 | 58.61 | 51.97 | 59.84 | 55.90 | 63.22 | 56.97 |
| 5 | Avista Corp. | 1.27 | 3.84% | $33.09 | 33.60 | 31.02 | 32.47 | 30.35 | 32.88 | 30.45 | 35.96 | 30.55 | 35.98 | 33.19 | 37.37 | 33.20 |
| 6 | Black Hills Corp. | 1.56 | 2.93% | $53.28 | 62.13 | 52.70 | 53.89 | 50.39 | 54.05 | 47.87 | 55.11 | 47.11 | 57.17 | 53.57 | 55.59 | 49.82 |
| 7 | CenterPoint Energy Inc. | 0.95 | 3.96% | $24.02 | 25.62 | 24.30 | 24.91 | 23.47 | 25.09 | 23.73 | 24.84 | 21.07 | 25.56 | 23.85 | 24.38 | 21.41 |
| 8 | CMS Energy Corp. | 1.08 | 3.45% | $31.35 | 31.20 | 28.87 | 30.54 | 27.90 | 30.83 | 29.15 | 32.91 | 29.59 | 33.46 | 32.05 | 36.87 | 32.79 |
| 9 | Consolidated Edison Inc. | 2.52 | 4.21% | $59.80 | 57.85 | 55.28 | 57.90 | 54.58 | 58.12 | 55.80 | 64.00 | 56.40 | 64.73 | 61.45 | 68.92 | 62.62 |
| 10 | Dominion Resources, Inc. | 2.40 | 3.39% | $70.74 | 71.62 | 67.58 | 70.38 | 64.71 | 71.33 | 67.29 | 72.24 | 65.53 | 74.59 | 71.34 | 80.89 | 71.34 |
| 11 | DTE Energy Co. | 2.69 | 3.40% | $79.06 | 78.10 | 73.74 | 78.26 | 71.60 | 78.89 | 74.62 | 82.33 | 75.76 | 84.42 | 79.54 | 90.77 | 80.71 |
| 12 | Duke Energy Corp. | 3.15 | 4.09% | $76.98 | 74.48 | 70.81 | 74.00 | 69.48 | 75.21 | 72.95 | 82.68 | 74.33 | 83.90 | 78.51 | 87.29 | 80.16 |
| 13 | Edison International | 1.45 | 2.43% | $59.61 | 58.11 | 54.72 | 59.18 | 54.32 | 59.54 | 54.12 | 62.90 | 55.88 | 63.66 | 61.39 | 68.74 | 62.78 |
| 14 | El Paso Electric Co. | 1.11 | 2.91% | $38.09 | 40.43 | 36.81 | 39.42 | 35.39 | 39.41 | 36.05 | 38.26 | 35.34 | 39.63 | 37.37 | 42.17 | 36.77 |
| 15 | Empire District Electric Co. | 1.03 | 3.88% | $26.54 | 25.87 | 24.36 | 26.00 | 24.02 | 25.95 | 24.00 | 29.24 | 24.09 | 28.87 | 27.52 | 31.20 | 27.40 |
| 16 | Entergy Corp. | 3.32 | 4.16% | $79.74 | 82.48 | 72.81 | 77.45 | 70.70 | 78.37 | 75.29 | 84.58 | 76.51 | 84.44 | 80.04 | 92.02 | 82.18 |
| 17 | FirstEnergy Corp. | 1.44 | 4.12% | $34.98 | 34.76 | 31.12 | 34.25 | 29.98 | 34.95 | 33.35 | 37.64 | 33.04 | 37.72 | 35.69 | 40.84 | 36.47 |
| 18 | Great Plains Energy Inc. | 0.94 | 3.63% | $25.91 | 26.95 | 24.71 | 25.91 | 24.09 | 25.80 | 23.91 | 27.00 | 24.11 | 27.38 | 25.63 | 29.46 | 25.94 |
| 19 | IDACORP Inc. | 1.76 | 3.00% | $58.67 | 58.79 | 53.55 | 56.80 | 51.70 | 56.97 | 53.20 | 64.12 | 53.39 | 63.52 | 60.55 | 70.05 | 61.35 |
| 20 | Integrys Energy Group Inc. | 2.72 | 3.90% | $69.76 | 71.10 | 65.51 | 67.93 | 63.59 | 68.55 | 64.48 | 73.12 | 64.63 | 74.12 | 70.75 | 80.88 | 72.47 |
| 21 | ITC Holdings Corp. | 0.61 | 1.63% | $37.47 | 37.22 | 35.03 | 37.71 | 34.60 | 38.14 | 35.14 | 39.94 | 34.05 | 40.67 | 37.71 | 42.01 | 37.38 |
| 22 | NextEra Energy, Inc. | 2.90 | 2.94% | $98.72 | 102.46 | 93.80 | 98.63 | 91.79 | 98.52 | 92.57 | 100.51 | 90.33 | 105.94 | 99.65 | 110.84 | 99.57 |
| 23 | Northeast Utilities | 1.57 | 3.31% | $47.49 | 47.37 | 43.78 | 45.90 | 41.92 | 46.57 | 43.88 | 49.98 | 44.37 | 50.92 | 48.65 | 56.66 | 49.93 |
| 24 | Northwestern Corporation | 1.60 | 3.19% | $50.23 | 52.70 | 46.21 | 48.76 | 45.24 | 49.55 | 45.12 | 53.45 | 45.14 | 54.42 | 51.40 | 58.70 | 52.02 |
| 25 | OGE Energy Corp. | 0.95 | 2.62% | $36.19 | 39.29 | 35.95 | 37.60 | 34.88 | 37.76 | 35.15 | 37.56 | 33.06 | 37.90 | 35.64 | 36.70 | 32.85 |
| 26 | Otter Tail Corp. | 1.21 | 4.16% | $29.06 | 30.43 | 27.90 | 28.91 | 27.16 | 28.70 | 26.67 | 31.20 | 26.53 | 31.40 | 28.66 | 32.72 | 28.40 |
| 27 | PG&E Corp. | 1.82 | 3.80% | $47.84 | 48.09 | 44.65 | 46.48 | 42.92 | 48.24 | 43.76 | 50.36 | 44.17 | 51.46 | 48.92 | 55.24 | 49.79 |
| 28 | Pinnacle West Capital Corp. | 2.33 | 3.96% | $58.85 | 57.95 | 53.29 | 56.97 | 52.13 | 57.74 | 54.13 | 61.56 | 54.59 | 63.50 | 60.61 | 71.11 | 62.60 |
| 29 | PNM Resources Inc. | 0.74 | 2.70% | $27.40 | 29.94 | 25.64 | 26.25 | 24.26 | 26.97 | 24.76 | 29.33 | 24.81 | 29.62 | 28.19 | 31.60 | 27.41 |
| 30 | Portland General Electric Co. | 1.12 | 3.22% | $34.78 | 34.74 | 31.93 | 34.47 | 31.41 | 34.55 | 31.70 | 36.86 | 32.07 | 37.29 | 35.50 | 40.31 | 36.51 |
| 31 | PPL Corp. | 1.49 | 4.33% | $34.39 | 35.52 | 32.65 | 34.64 | 31.79 | 34.72 | 32.41 | 35.02 | 32.09 | 36.81 | 34.78 | 38.14 | 34.11 |
| 32 | Public Service Enterprise Group Inc. | 1.48 | 3.82% | $38.73 | 40.68 | 35.11 | 37.41 | 34.05 | 38.32 | 36.04 | 41.63 | 36.37 | 42.06 | 39.04 | 43.77 | 40.31 |
| 33 | SCANA Corp. | 2.10 | 3.93% | $53.40 | 53.89 | 50.78 | 51.94 | 48.53 | 52.23 | 48.81 | 55.25 | 47.77 | 57.39 | 54.83 | 63.41 | 56.02 |
| 34 | Sempra Energy | 2.64 | 2.49% | $105.84 | 104.60 | 99.60 | 106.09 | 96.13 | 107.81 | 102.34 | 111.36 | 98.34 | 114.50 | 108.22 | 116.30 | 104.75 |
| 35 | Southern Co. (The) | 2.08 | 4.57% | $45.56 | 45.47 | 43.22 | 44.40 | 41.87 | 44.82 | 43.04 | 47.69 | 43.55 | 47.97 | 46.30 | 51.28 | 47.07 |
| 36 | TECO Energy Inc. | 0.88 | 4.74% | $18.56 | 18.48 | 17.42 | 18.10 | 16.91 | 18.14 | 16.98 | 19.87 | 17.35 | 20.17 | 19.12 | 21.29 | 18.89 |
| 37 | UIL Holdings Corp. | 1.73 | 4.48% | $38.62 | 38.89 | 35.11 | 37.34 | 34.34 | 37.93 | 35.35 | 41.87 | 35.33 | 42.56 | 39.10 | 46.33 | 39.25 |
| 38 | Vectren Corp. | 1.45 | 3.45% | $41.98 | 42.74 | 38.06 | 41.25 | 35.11 | 41.89 | 39.09 | 45.28 | 39.67 | 45.96 | 43.50 | 48.28 | 42.96 |
| 39 | Westar Energy Inc. | 1.39 | 3.73% | $37.24 | 38.23 | 36.04 | 37.09 | 34.53 | 37.07 | 33.76 | 37.91 | 33.73 | 39.62 | 37.24 | 43.15 | 38.52 |
| 40 | Wisconsin Energy Corp. | 1.56 | 3.34% | $46.77 | 47.02 | 43.56 | 45.37 | 41.90 | 45.60 | 42.53 | 49.84 | 43.01 | 50.54 | 47.50 | 55.39 | 49.03 |
| 41 | Xcel Energy Inc. | 1.20 | 3.70% | $32.44 | 32.26 | 30.73 | 32.06 | 29.60 | 32.48 | 30.12 | $33.76 | $30.18 | $34.10 | $32.95 | $37.58 | $33.49 |

**Data Source**
Prices from S&P CapitalIQ, a business unit of Standard and Poor's
Dividend from Latest Value Line Investment Survey

# PSC STAFF DCF ANALYSIS USING FERC COST OF EQUITY MODEL

| | Company | Moody's Rating | S&P Rating | Dividend Yield | I/B/E/S Growth Rate | GDP Growth Rate | Composite Growth Rate | Adj. Div. Factor | Adj. Div. Yield | DCF Result |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ALLETE, Inc. | A3 | BBB+ | 3.95% | 6.00% | 4.33% | 5.44% | 1.027 | 4.06% | 9.51% |
| 2 | Alliant Energy Corp. | A3 | A- | 3.40% | 4.90% | 4.33% | 4.71% | 1.024 | 3.48% | 8.19% |
| 3 | Ameren Corp. | Baa2 | BBB+ | 3.93% | 8.90% | 4.33% | 7.38% | 1.037 | 4.08% | 11.45% |
| 4 | American Electric Power Co. Inc. | Baa1 | BBB | 3.68% | 5.20% | 4.33% | 4.91% | 1.025 | 3.77% | 8.68% |
| 5 | Avista Corp. | Baa1 | BBB | 3.84% | 5.00% | 4.33% | 4.78% | 1.024 | 3.93% | 8.71% |
| 6 | Black Hills Corp. | Baa1 | BBB | 2.93% | 7.00% | 4.33% | 6.11% | 1.031 | 3.02% | 9.13% |
| 7 | CenterPoint Energy Inc. | Baa1 | A- | 3.96% | 3.87% | 4.33% | 4.02% | 1.020 | 4.03% | 8.06% |
| 8 | CMS Energy Corp. | Baa2 | BBB+ | 3.45% | 6.60% | 4.33% | 5.84% | 1.029 | 3.55% | 9.39% |
| 9 | Consolidated Edison Inc. | A3 | A- | 4.21% | 2.38% | 4.33% | 3.03% | 1.015 | 4.28% | 7.31% |
| 10 | Dominion Resources, Inc. | Baa2 | A- | 3.39% | 6.67% | 4.33% | 5.89% | 1.029 | 3.49% | 9.38% |
| 11 | DTE Energy Co. | A3 | BBB+ | 3.40% | 6.17% | 4.33% | 5.56% | 1.028 | 3.50% | 9.05% |
| 12 | Duke Energy Corp. | A3 | BBB+ | 4.09% | 4.79% | 4.33% | 4.64% | 1.023 | 4.19% | 8.82% |
| 13 | Edison International | A3 | BBB+ | 2.43% | 3.38% | 4.33% | 3.70% | 1.018 | 2.48% | 6.17% |
| 14 | El Paso Electric Co. | Baa1 | BBB | 2.91% | 7.00% | 4.33% | 6.11% | 1.031 | 3.00% | 9.11% |
| 15 | Empire District Electric Co. | Baa1 | BBB | 3.88% | 3.00% | 4.33% | 3.44% | 1.017 | 3.95% | 7.39% |
| 16 | Entergy Corp. | Baa3 | BBB | 4.16% | 0.39% | 4.33% | 1.70% | 1.009 | 4.20% | 5.90% |
| 17 | FirstEnergy Corp. | Baa3 | BBB- | 4.12% | -2.80% | 4.33% | -0.42% | 0.998 | 4.11% | |
| 18 | Great Plains Energy Inc. | Baa2 | BBB+ | 3.63% | 5.00% | 4.33% | 4.78% | 1.024 | 3.72% | 8.49% |
| 19 | IDACORP Inc. | Baa1 | BBB | 3.00% | 4.00% | 4.33% | 4.11% | 1.021 | 3.06% | 7.17% |
| 20 | Integrys Energy Group Inc. | A3 | A- | 3.90% | 5.00% | 4.33% | 4.78% | 1.024 | 3.99% | 8.77% |
| 21 | ITC Holdings Corp. | Baa2 | A- | 1.63% | 11.76% | 4.33% | 9.28% | 1.046 | 1.70% | 10.99% |
| 22 | NextEra Energy, Inc. | Baa1 | A- | 2.94% | 6.68% | 4.33% | 5.90% | 1.029 | 3.02% | 8.92% |
| 23 | Northeast Utilities | Baa1 | A- | 3.31% | 5.88% | 4.33% | 5.36% | 1.027 | 3.39% | 8.76% |
| 24 | Northwestern Corporation | A3 | BBB | 3.19% | 7.05% | 4.33% | 6.14% | 1.031 | 3.28% | 9.43% |
| 25 | OGE Energy Corp. | A3 | A- | 2.62% | 7.05% | 4.33% | 6.14% | 1.031 | 2.71% | 8.85% |
| 26 | Otter Tail Corp. | Baa2 | BBB | 4.16% | 6.00% | 4.33% | 5.44% | 1.027 | 4.28% | 9.72% |
| 27 | PG&E Corp. | Baa1 | BBB | 3.80% | 8.51% | 4.33% | 7.12% | 1.036 | 3.94% | 11.06% |
| 28 | Pinnacle West Capital Corp. | Baa1 | A- | 3.96% | 3.61% | 4.33% | 3.85% | 1.019 | 4.04% | 7.89% |
| 29 | PNM Resources Inc. | Baa3 | BBB | 2.70% | 9.86% | 4.33% | 8.02% | 1.040 | 2.81% | 10.83% |
| 30 | Portland General Electric Co. | A3 | BBB | 3.22% | 7.97% | 4.33% | 6.76% | 1.034 | 3.33% | 10.09% |
| 31 | PPL Corp. | Baa3 | BBB | 4.33% | -2.10% | 4.33% | 0.04% | 1.000 | 4.33% | |
| 32 | Public Service Enterprise Group Inc. | (P)Baa2 | BBB+ | 3.82% | 2.68% | 4.33% | 3.23% | 1.016 | 3.88% | 7.11% |
| 33 | SCANA Corp. | Baa3 | BBB+ | 3.93% | 5.35% | 4.33% | 5.01% | 1.025 | 4.03% | 9.04% |
| 34 | Sempra Energy | Baa1 | BBB+ | 2.49% | 7.71% | 4.33% | 6.58% | 1.033 | 2.58% | 9.16% |
| 35 | Southern Co. (The) | Baa1 | A | 4.57% | 3.34% | 4.33% | 3.67% | 1.018 | 4.65% | 8.32% |
| 36 | TECO Energy Inc. | (P)Baa1 | BBB+ | 4.74% | 6.43% | 4.33% | 5.73% | 1.029 | 4.88% | 10.61% |
| 37 | UIL Holdings Corp. | Baa2 | BBB | 4.48% | 5.37% | 4.33% | 5.02% | 1.025 | 4.59% | 9.62% |
| 38 | Vectren Corp. | NR | A- | 3.45% | 4.50% | 4.33% | 4.44% | 1.022 | 3.53% | 7.97% |
| 39 | Westar Energy Inc. | Baa1 | BBB+ | 3.73% | 3.37% | 4.33% | 3.69% | 1.018 | 3.80% | 7.49% |
| 40 | Wisconsin Energy Corp. | A2 | A- | 3.34% | 5.44% | 4.33% | 5.07% | 1.025 | 3.42% | 8.49% |
| 41 | Xcel Energy Inc. | A3 | A- | 3.70% | 4.33% | 4.33% | 4.33% | 1.022 | 3.78% | 8.11% |
| | **Min** | | | | | | | | | **5.90%** |
| | **Max** | | | | | | | | | **11.45%** |

Norminal GDP($billions)

| | | | |
|---|---|---|---|
| | | | Compound Annual |
| **Source** | **2015** | **2040** | **Growth Rate** |
| U.S. Energy Information Administration | | | |
| Real Gross Domestic Product | 14,693 | 26,670 | 2.41% |
| GDP Deflator | 1.211 | 1.913 | 1.85% |
| **Nominal GDP** | | | **4.26%** |

| | | | |
|---|---|---|---|
| Blue Chip Economic Indicators(October 2014 Edition) | | | |
| Real GDP consensus long range forecast(2021-25) | | | 2.30% |
| GDP Deflator (2021-25) | | | 2.10% |
| **Nominal GDP** | | | **4.40%** |

**Average GDP Growth Rate** **4.33%**

## PSC Staff Proxy Group and NYTO Statistics: Common Equity Ratio ($ Millions)

| | Company | Long-term Debt (LTD) | Current portion of LTD | Total Long-term Debt | Preferred Stock | Minority Interest | Customer Deposits | Common Equity | Total Capital | Common Equity Ratio | Moody's Rating | S&P Rating |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ALLETE, Inc. | $1,083 | $27 | $1,110 | $0 | $0 | $0 | $1,343 | $2,453 | 54.74% | A3 | BBB+ |
| 2 | Alliant Energy Corp. | $2,978 | $359 | $3,336 | $0 | $202 | $0 | $3,281 | $6,820 | 48.12% | A3 | A- |
| 3 | Ameren Corp. | $5,210 | $529 | $5,739 | $0 | $142 | $105 | $6,544 | $12,530 | 52.23% | Baa2 | BBB+ |
| 4 | American Electric Power Co. Inc. | $16,828 | $1,549 | $18,377 | $0 | $1 | $299 | $16,085 | $34,762 | 46.27% | Baa1 | BBB |
| 5 | Avista Corp. | $1,320 | $17 | $1,337 | $0 | $36 | $88 | $1,298 | $2,759 | 47.06% | Baa1 | BBB |
| 6 | Black Hills Corp. | $1,403 | $3 | $1,406 | $0 | $0 | $0 | $1,308 | $2,714 | 48.19% | Baa1 | BBB |
| 7 | CenterPoint Energy Inc. | $7,817 | $497 | $8,314 | $0 | $0 | $0 | $4,329 | $12,643 | 34.24% | Baa1 | A- |
| 8 | CMS Energy Corp. | $7,101 | $541 | $7,642 | $0 | $37 | $0 | $3,454 | $11,133 | 31.02% | Baa2 | BBB+ |
| 9 | Consolidated Edison Inc. | $10,489 | $487 | $10,976 | $0 | $0 | $321 | $12,245 | $23,542 | 52.01% | A3 | A- |
| 10 | Dominion Resources, Inc. | $18,214 | $1,519 | $19,733 | $0 | $0 | $95 | $11,642 | $31,470 | 36.99% | Baa2 | A- |
| 11 | DTE Energy Co. | $6,723 | $891 | $7,614 | $0 | $33 | $0 | $7,921 | $15,568 | 50.88% | A3 | BBB+ |
| 12 | Duke Energy Corp. | $38,160 | $2,123 | $40,283 | $0 | $78 | $0 | $41,330 | $81,691 | 50.59% | A3 | BBB+ |
| 13 | Edison International | $9,825 | $601 | $10,426 | $0 | $1,753 | $201 | $9,938 | $22,318 | 44.53% | A3 | BBB+ |
| 14 | El Paso Electric Co. | $1,000 | $0 | $1,000 | $0 | $0 | $0 | $944 | $1,943 | 48.56% | Baa1 | BBB |
| 15 | Empire District Electric Co. | $739 | $0 | $739 | $0 | $0 | $13 | $750 | $1,502 | 49.94% | Baa1 | BBB |
| 16 | Entergy Corp. | $12,139 | $457 | $12,596 | $0 | $305 | $87 | $9,632 | $22,620 | 42.58% | Baa3 | BBB |
| 17 | FirstEnergy Corp. | $15,677 | $1,341 | $17,018 | $0 | $3 | $0 | $12,692 | $29,713 | 42.72% | Baa3 | BBB- |
| 18 | Great Plains Energy Inc. | $3,516 | $1 | $3,517 | $39 | $0 | $0 | $3,474 | $7,030 | 49.42% | Baa2 | BBB+ |
| 19 | IDACORP Inc. | $1,615 | $1 | $1,616 | $0 | $4 | $0 | $1,851 | $3,471 | 53.32% | Baa1 | BBB |
| 20 | Integrys Energy Group Inc. | $2,956 | $100 | $3,056 | $0 | $52 | $0 | $3,261 | $6,370 | 51.20% | A3 | A- |
| 21 | ITC Holdings Corp. | $3,412 | $100 | $3,512 | $0 | $0 | $0 | $1,614 | $5,126 | 31.48% | Baa2 | A- |
| 22 | NextEra Energy, Inc. | $23,969 | $3,766 | $27,735 | $0 | $0 | $452 | $18,040 | $46,227 | 39.02% | Baa1 | A- |
| 23 | Northeast Utilities | $7,777 | $533 | $8,310 | $0 | $156 | $0 | $9,612 | $18,077 | 53.17% | Baa1 | A- |
| 24 | Northwestern Corporation | $1,155 | $0 | $1,155 | $0 | $0 | $0 | $1,031 | $2,186 | 47.15% | A3 | BBB |
| 25 | OGE Energy Corp. | $2,300 | $100 | $2,400 | $0 | $0 | $71 | $3,037 | $5,508 | 55.14% | A3 | A- |
| 26 | Otter Tail Corp. | $390 | $0 | $390 | $0 | $0 | $0 | $535 | $925 | 57.84% | Baa2 | BBB |
| 27 | PG&E Corp. | $12,717 | $889 | $13,606 | $0 | $252 | $0 | $14,342 | $28,200 | 50.86% | Baa1 | BBB |
| 28 | Pinnacle West Capital Corp. | $2,796 | $540 | $3,337 | $0 | $146 | $76 | $4,194 | $7,753 | 54.10% | Baa1 | A- |
| 29 | PNM Resources Inc. | $1,670 | $75 | $1,745 | $0 | $89 | $13 | $1,674 | $3,521 | 47.53% | Baa3 | BBB |
| 30 | Portland General Electric Co. | $1,916 | $0 | $1,916 | $0 | $1 | $0 | $1,819 | $3,736 | 48.69% | A3 | BBB |
| 31 | PPL Corp. | $20,710 | $319 | $21,029 | $0 | $0 | $50 | $12,466 | $33,545 | 37.16% | Baa3 | BBB |
| 32 | Public Service Enterprise Group | $7,862 | $781 | $8,643 | $0 | $1 | $0 | $11,608 | $20,252 | 57.32% | (P)Baa2 | BBB+ |
| 33 | SCANA Corp. | $5,590 | $60 | $5,650 | $0 | $0 | $88 | $4,664 | $10,402 | 44.84% | Baa3 | BBB+ |
| 34 | Sempra Energy | $11,253 | $1,147 | $12,400 | $0 | $842 | $154 | $11,008 | $24,404 | 45.11% | Baa1 | BBB+ |
| 35 | Southern Co. (The) | $21,004 | $440 | $21,444 | $0 | $1,131 | $380 | $19,008 | $41,963 | 45.30% | Baa1 | A |
| 36 | TECO Energy Inc. | $2,838 | $83 | $2,921 | $0 | $0 | $165 | $2,334 | $5,419 | 43.06% | (P)Baa1 | BBB+ |
| 37 | UIL Holdings Corp. | $1,724 | $12 | $1,736 | $0 | $0 | $0 | $1,354 | $3,090 | 43.82% | Baa2 | BBB |
| 38 | Vectren  Corp. | $1,777 | $30 | $1,807 | $0 | $0 | $50 | $1,554 | $3,412 | 45.56% | NR | A- |
| 39 | Westar Energy Inc. | $3,164 | $277 | $3,441 | $0 | $6 | $0 | $3,063 | $6,510 | 47.05% | Baa1 | BBB+ |
| 40 | Wisconsin Energy Corp. | $4,279 | $322 | $4,601 | $0 | $30 | $0 | $4,233 | $8,865 | 47.75% | A2 | A- |
| 41 | Xcel Energy Inc. | $10,911 | $281 | $11,192 | $0 | $0 | $276 | $9,566 | $21,033 | 45.48% | A3 | A- |
| | ***Total*** | ***$314,006*** | ***$20,800*** | ***$334,806*** | ***$39*** | ***$5,299*** | ***$2,983*** | ***$290,078*** | ***$633,204*** | | | |
| | **Average** | $7,659 | $507 | $8,166 | $1 | $129 | $73 | $7,075 | $15,444 | 46.88% | Baa1 | BBB+ |
| | **Median** | $4,279 | $319 | $4,601 | $0 | $1 | $0 | $4,194 | $8,865 | 47.53% | Baa1 | BBB+ |

Total Capital= Common Equity+Total LTD+Customer Deposits+Pref Stock+Minority Interest

**Source:**
2013 Annual reports(10K) using S&P CapitalIQ

## PSC Staff Proxy Group and NYTO Statistics: Common Equity Ratio ($ Millions)

| | Company | Long-term Debt (LTD) | Current portion of LTD | Total Long-term Debt | Preferred Stock | Minority Interest | Customer Deposits | Common Equity | Total Capital | Common Equity Ratio | Moody's Rating | S&P Rating |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **New York Transmission Owners** | | | | | | | | | | | |
| 1 | Central Hudson Gas & Electric Corp. | $476 | $14 | $490 | $0 | $0 | $7 | $507 | $1,004 | 50.51% | A2 | A |
| 2 | Con Edison | $10,489 | $487 | $10,976 | $0 | $0 | $321 | $12,245 | $23,542 | 52.01% | A3 | A- |
| 3 | Long Island Power Authority | $7,231 | $170 | $7,401 | $0 | $0 | | $378 | $7,779 | 4.86% | NR | NR |
| 4 | New York Power Authority | $1,148 | $93 | $1,241 | $0 | $0 | | $3,719 | $4,960 | 74.98% | NR | NR |
| 5 | Niagara Mohawk Power Corporation | $2,554 | $46 | $2,600 | $29 | $0 | $30 | $3,877 | $6,536 | 59.32% | A2 | A- |
| 6 | NYSEG | $880 | $0 | $880 | $0 | $0 | $13 | $1,133 | $2,026 | 55.91% | A3 | BBB+ |
| 7 | Orange & Rockland | $600 | $6 | $606 | $0 | $0 | $9 | $620 | $1,235 | 50.20% | A3 | A- |
| 8 | Rochester Gas & Electric Corp. | $707 | $0 | $707 | $0 | $0 | $5 | $735 | $1,447 | 50.78% | Baa1 | BBB+ |
| | **Average** | | | | | | | | | **49.82%** | **A3** | **A-** |
| | **Median** | | | | | | | | | **50.78%** | **A3** | **A-** |
| | **IOU New York Transmission Owners** | | | | | | | | | | | |
| 1 | Central Hudson Gas & Electric Corp. | $476 | $14 | $490 | $0 | $0 | $7 | $507 | $1,004 | 50.51% | A2 | A |
| 2 | Con Edison | $10,489 | $487 | $10,976 | $0 | $0 | $321 | $12,245 | $23,542 | 52.01% | A3 | A- |
| 3 | Niagara Mohawk Power Corporation | $2,554 | $46 | $2,600 | $29 | $0 | $30 | $3,877 | $6,536 | 59.32% | A2 | A- |
| 4 | NYSEG | $880 | $0 | $880 | $0 | $0 | $13 | $1,133 | $2,026 | 55.91% | A3 | BBB+ |
| 5 | Orange & Rockland | $600 | $6 | $606 | $0 | $0 | $9 | $620 | $1,235 | 50.20% | A3 | A- |
| 6 | Rochester Gas & Electric Corp. | $707 | $0 | $707 | $0 | $0 | $5 | $735 | $1,447 | 50.78% | Baa1 | BBB+ |
| | **Average** | | | | | | | | | **53.12%** | **A3** | **A-** |
| | **Median** | | | | | | | | | **52.01%** | **A3** | **A-** |

## NY Transco Proxy Group Statistics: Common Equity Ratio ($ Millions)

| | Company | Long-term Debt (LTD) | Current portion of LTD | Total Long-term Debt | Preferred Stock | Minority Interest | Customer Deposits | Common Equity | Total Capital | Common Equity Ratio | Moody's Rating | S&P Rating |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ALLETE, Inc. | $1,083 | $27 | $1,110 | $0 | $0 | $0 | $1,343 | $2,453 | 54.74% | A3 | BBB+ |
| 2 | Alliant Energy Corp. | $2,978 | $359 | $3,336 | $0 | $202 | $0 | $3,281 | $6,820 | 48.12% | A3 | A- |
| 3 | Ameren Corp. | $5,210 | $529 | $5,739 | $0 | $142 | $105 | $6,544 | $12,530 | 52.23% | Baa2 | BBB+ |
| 4 | American Electric Power Co. Inc. | $16,828 | $1,549 | $18,377 | $0 | $1 | $299 | $16,085 | $34,762 | 46.27% | Baa1 | BBB |
| 5 | Avista Corp. | $1,320 | $17 | $1,337 | $0 | $36 | $88 | $1,298 | $2,759 | 47.06% | Baa1 | BBB |
| 6 | Black Hills Corp. | $1,403 | $3 | $1,406 | $0 | $0 | $0 | $1,308 | $2,714 | 48.19% | Baa1 | BBB |
| 7 | CenterPoint Energy Inc. | $7,817 | $497 | $8,314 | $0 | $0 | $0 | $4,329 | $12,643 | 34.24% | Baa1 | A- |
| 8 | CMS Energy Corp. | $7,101 | $541 | $7,642 | $0 | $37 | $0 | $3,454 | $11,133 | 31.02% | Baa2 | BBB+ |
| 9 | Consolidated Edison Inc. | $10,489 | $487 | $10,976 | $0 | $0 | $321 | $12,245 | $23,542 | 52.01% | A3 | A- |
| 10 | Dominion Resources, Inc. | $18,214 | $1,519 | $19,733 | $0 | $0 | $95 | $11,642 | $31,470 | 36.99% | Baa2 | A- |
| 11 | DTE Energy Co. | $6,723 | $891 | $7,614 | $0 | $33 | $0 | $7,921 | $15,568 | 50.88% | A3 | BBB+ |
| 12 | Duke Energy Corp. | $38,160 | $2,123 | $40,283 | $0 | $78 | $0 | $41,330 | $81,691 | 50.59% | A3 | BBB+ |
| 13 | Edison International | $9,825 | $601 | $10,426 | $0 | $1,753 | $201 | $9,938 | $22,318 | 44.53% | A3 | BBB+ |
| 14 | El Paso Electric Co. | $1,000 | $0 | $1,000 | $0 | $0 | $0 | $944 | $1,943 | 48.56% | Baa1 | BBB |
| 15 | Empire District Electric Co. | $739 | $0 | $739 | $0 | $0 | $13 | $750 | $1,502 | 49.94% | Baa1 | BBB |
| 16 | Great Plains Energy Inc. | $3,516 | $1 | $3,517 | $39 | $0 | $0 | $3,474 | $7,030 | 49.42% | Baa2 | BBB+ |
| 17 | IDACORP Inc. | $1,615 | $1 | $1,616 | $0 | $4 | $0 | $1,851 | $3,471 | 53.32% | Baa1 | BBB |
| 18 | ITC Holdings Corp. | $3,412 | $100 | $3,512 | $0 | $0 | $0 | $1,614 | $5,126 | 31.48% | Baa2 | A- |
| 19 | NextEra Energy, Inc. | $23,969 | $3,766 | $27,735 | $0 | $0 | $452 | $18,040 | $46,227 | 39.02% | Baa1 | A- |
| 20 | Northeast Utilities | $7,777 | $533 | $8,310 | $0 | $156 | $0 | $9,612 | $18,077 | 53.17% | Baa1 | A- |
| 21 | Northwestern Corporation | $1,155 | $0 | $1,155 | $0 | $0 | $0 | $1,031 | $2,186 | 47.15% | A3 | BBB |
| 22 | OGE Energy Corp. | $2,300 | $100 | $2,400 | $0 | $0 | $71 | $3,037 | $5,508 | 55.14% | A3 | A- |
| 23 | Otter Tail Corp. | $390 | $0 | $390 | $0 | $0 | $0 | $535 | $925 | 57.84% | Baa2 | BBB |
| 24 | PG&E Corp. | $12,717 | $889 | $13,606 | $0 | $252 | $0 | $14,342 | $28,200 | 50.86% | Baa1 | BBB |
| 25 | Pinnacle West Capital Corp. | $2,796 | $540 | $3,337 | $0 | $146 | $76 | $4,194 | $7,753 | 54.10% | Baa1 | A- |
| 26 | Portland General Electric Co. | $1,916 | $0 | $1,916 | $0 | $1 | $0 | $1,819 | $3,736 | 48.69% | A3 | BBB |
| 27 | Public Service Enterprise Group | $7,862 | $781 | $8,643 | $0 | $1 | $0 | $11,608 | $20,252 | 57.32% | (P)Baa2 | BBB+ |
| 28 | Sempra Energy | $11,253 | $1,147 | $12,400 | $0 | $842 | $154 | $11,008 | $24,404 | 45.11% | Baa1 | BBB+ |
| 29 | Westar Energy Inc. | $3,164 | $277 | $3,441 | $0 | $6 | $0 | $3,063 | $6,510 | 47.05% | Baa1 | BBB+ |
| 30 | Xcel Energy Inc. | $10,911 | $281 | $11,192 | $0 | $0 | $276 | $9,566 | $21,033 | 45.48% | A3 | A- |
| | ***Total*** | ***$223,642*** | ***$17,560*** | ***$241,202*** | ***$39*** | ***$3,689*** | ***$2,150*** | ***$217,205*** | ***$464,285*** | | | |
| | **Average** | $7,455 | $585 | $8,040 | $1 | $123 | $72 | $7,240 | $15,476 | 47.68% | Baa1 | BBB+ |
| | **Median** | $4,363 | $423 | $4,628 | $0 | $1 | $0 | $3,834 | $9,443 | 48.63% | Baa1 | BBB+ |

Total Capital= Common Equity+Total LTD+Customer Deposits+Pref Stock+Minority Interest

**Source:**
2013 Annual reports(10K) using S&P CapitalIQ

# Electric Transmission Co. Debt Issuances

| | Maturity Date | Issuer | Coupon Rate (%) | Coupon Type | Offering Date | Offering Amount ($mm) | Issuer Credit Rating | Term |
|---|---|---|---|---|---|---|---|---|
| 1 | Dec-01-2023 | Alabama Power Co. | 3.55 | Fixed | Dec-03-2013 | 300.0 | A | 10 |
| 2 | Aug-15-2044 | Alabama Power Co. | 4.15 | Fixed | Aug-20-2014 | 400.0 | A | 30 |
| 3 | Sep-01-2044 | American Transmission Systems, Incorporated | 5.0 | Fixed | Sep-22-2014 | 400.0 | BBB- | 30 |
| 4 | May-15-2044 | Appalachian Power Company | 4.4 | Fixed | May-05-2014 | 300.0 | BBB | 30 |
| 5 | Jun-15-2024 | Arizona Public Service Co. | 3.35 | Fixed | Jun-09-2014 | 250.0 | A- | 10 |
| 6 | Jan-15-2044 | Arizona Public Service Co. | 4.7 | Fixed | Jan-07-2014 | 250.0 | A- | 30 |
| 7 | Sep-01-2024 | Atlantic City Electric Company | 3.375 | Fixed | Aug-18-2014 | 150.0 | BBB+ | 10 |
| 8 | Apr-01-2044 | Centerpoint Energy Houston Electric, LLC | 4.5 | Fixed | Mar-12-2014 | 600.0 | A- | 30 |
| 9 | Nov-01-2024 | Commonwealth Edison Company | 3.1 | Fixed | Nov-03-2014 | 250.0 | BBB | 10 |
| 10 | Jan-15-2019 | Commonwealth Edison Company | 2.15 | Fixed | Jan-06-2014 | 300.0 | BBB | 5 |
| 11 | Jan-15-2044 | Commonwealth Edison Company | 4.7 | Fixed | Jan-06-2014 | 350.0 | BBB | 30 |
| 12 | Mar-01-2025 | DTE Electric Company | 3.375 | Fixed | Jun-23-2014 | 350.0 | BBB+ | 11 |
| 13 | Jul-01-2044 | DTE Electric Company | 4.3 | Fixed | Jun-23-2014 | 350.0 | BBB+ | 30 |
| 14 | Mar-30-2044 | Duke Energy Corporation (NYSE:DUK) | 4.375 | Fixed | Mar-03-2014 | 400.0 | BBB+ | 30 |
| 15 | Apr-15-2024 | Duke Energy Corporation (NYSE:DUK) | 3.75 | Fixed | Apr-01-2014 | 600.0 | BBB+ | 10 |
| 16 | Dec-01-2044 | Duke Energy Progress, Inc. | 4.15 | Fixed | Nov-17-2014 | 500.0 | BBB+ | 30 |
| 17 | Dec-01-2044 | El Paso Electric Co. (NYSE:EE) | 5.0 | Fixed | Nov-24-2014 | 150.0 | BBB | 30 |
| 18 | Dec-15-2044 | Entergy Arkansas, Inc. | 4.95 | Fixed | Dec-03-2014 | 250.0 | BBB | 30 |
| 19 | Jun-01-2024 | Entergy Arkansas, Inc. | 3.7 | Fixed | Mar-10-2014 | 375.0 | BBB | 10 |
| 20 | Apr-01-2025 | Entergy Gulf States Louisiana, LLC | 3.78 | Fixed | Jun-24-2014 | 110.0 | BBB | 11 |
| 21 | Jul-15-2044 | Entergy Louisiana LLC | 5.0 | Fixed | Jun-17-2014 | 170.0 | BBB | 30 |
| 22 | Apr-01-2025 | Entergy Louisiana LLC | 3.78 | Fixed | Jun-24-2014 | 190.0 | BBB | 11 |
| 23 | Jan-15-2045 | Entergy Louisiana LLC | 4.95 | Fixed | Nov-18-2014 | 250.0 | BBB | 30 |
| 24 | Jul-01-2024 | Entergy Mississippi, Inc. | 3.75 | Fixed | Mar-18-2014 | 100.0 | BBB | 10 |
| 25 | Jun-01-2024 | Exelon Corporation (NYSE:EXC) | 2.5 | Fixed | Jun-12-2014 | 1.0 | BBB | 10 |
| 26 | Jul-15-2044 | FirstEnergy Transmission, LLC | 5.45 | Fixed | May-14-2014 | 400.0 | BBB- | 30 |
| 27 | Jan-15-2025 | FirstEnergy Transmission, LLC | 4.35 | Fixed | May-14-2014 | 600.0 | BBB- | 11 |
| 28 | Jun-01-2024 | Florida Power & Light Company | 3.25 | Fixed | May-12-2014 | 500.0 | A- | 10 |
| 29 | Oct-01-2044 | Florida Power & Light Company | 4.05 | Fixed | Sep-02-2014 | 500.0 | A- | 30 |
| 30 | Oct-01-2044 | Gulf Power Company | 4.55 | Fixed | Sep-16-2014 | 200.0 | A | 30 |
| 31 | Jun-15-2024 | ITC Holdings Corp. (NYSE:ITC) | 3.65 | Fixed | May-28-2014 | 400.0 | A- | 10 |
| 32 | Jul-15-2044 | Kansas Gas and Electric Company | 4.3 | Fixed | Jun-25-2014 | 250.0 | BBB+ | 30 |
| 33 | Apr-15-2025 | Metropolitan Edison Company | 4.0 | Fixed | Jun-05-2014 | 250.0 | BBB- | 11 |
| 34 | Oct-15-2024 | MidAmerican Energy Company | 3.5 | Fixed | Mar-31-2014 | 300.0 | A- | 11 |
| 35 | Oct-15-2044 | MidAmerican Energy Company | 4.4 | Fixed | Mar-31-2014 | 400.0 | A- | 31 |
| 36 | Aug-20-2019 | National Grid North America Inc. | 4.0 | Fixed | Aug-20-2014 | 93.1 | A- | 5 |
| 37 | Sep-15-2019 | NextEra Energy Capital Holdings, Inc. | 2.4 | Fixed | Jun-03-2014 | 350.0 | A- | 5 |
| 38 | Sep-15-2019 | NextEra Energy Capital Holdings, Inc. | 2.7 | Fixed | Mar-06-2014 | 350.0 | A- | 6 |
| 39 | Oct-01-2034 | Niagara Mohawk Power Corporation | 4.278 | Fixed | Sep-22-2014 | 400.0 | A- | 20 |
| 40 | Oct-01-2024 | Niagara Mohawk Power Corporation | 3.508 | Fixed | Sep-22-2014 | 500.0 | A- | 10 |
| 41 | May-15-2044 | Northern States Power Company | 4.125 | Fixed | May-06-2014 | 300.0 | A- | 30 |
| 42 | Jun-15-2024 | Northern States Power Company-Wisconsin | 3.3 | Fixed | Jun-16-2014 | 100.0 | A- | 10 |
| 43 | Mar-01-2044 | NSTAR Electric Company | 4.4 | Fixed | Mar-04-2014 | 300.0 | A- | 30 |
| 44 | Dec-15-2044 | Oklahoma Gas and Electric Company | 4.0 | Fixed | Dec-08-2014 | 250.0 | A- | 30 |
| 45 | Mar-15-2044 | Oklahoma Gas and Electric Company | 4.55 | Fixed | Mar-18-2014 | 250.0 | A- | 30 |
| 46 | Jun-01-2019 | Oncor Electric Delivery Company LLC | 2.15 | Fixed | Nov-20-2014 | 250.0 | BBB+ | 5 |
| 47 | Aug-15-2024 | Pacific Gas and Electric Company | 3.4 | Fixed | Aug-07-2014 | 350.0 | BBB | 10 |
| 48 | Feb-15-2024 | Pacific Gas and Electric Company | 3.75 | Fixed | Feb-18-2014 | 450.0 | BBB | 10 |
| 49 | Feb-15-2044 | Pacific Gas and Electric Company | 4.75 | Fixed | Feb-18-2014 | 450.0 | BBB | 30 |
| 50 | Mar-15-2045 | Pacific Gas and Electric Company | 4.3 | Fixed | Nov-03-2014 | 500.0 | BBB | 30 |
| 51 | Apr-01-2024 | PacifiCorp | 3.6 | Fixed | Mar-10-2014 | 425.0 | A- | 10 |
| 52 | Oct-01-2044 | PECO Energy Company | 4.15 | Fixed | Sep-08-2014 | 300.0 | BBB | 30 |
| 53 | Apr-15-2025 | Pennsylvania Electric Company | 4.15 | Fixed | Jun-05-2014 | 200.0 | BBB- | 11 |
| 54 | Mar-15-2024 | Potomac Electric Power Company | 3.6 | Fixed | Mar-11-2014 | 400.0 | BBB+ | 10 |
| 55 | Jun-15-2044 | PPL Electric Utilities Corporation | 4.125 | Fixed | Jun-02-2014 | 300.0 | BBB | 30 |
| 56 | Mar-15-2044 | Public Service Co. of Colorado | 4.3 | Fixed | Mar-03-2014 | 300.0 | A- | 30 |
| 57 | Jun-01-2019 | Public Service Electric and Gas Company | 1.8 | Fixed | May-28-2014 | 250.0 | BBB+ | 5 |
| 58 | Aug-15-2019 | Public Service Electric and Gas Company | 2.0 | Fixed | Aug-06-2014 | 250.0 | BBB+ | 5 |
| 59 | Nov-15-2024 | Public Service Electric and Gas Company | 3.05 | Fixed | Nov-04-2014 | 250.0 | BBB+ | 10 |
| 60 | Aug-15-2024 | Public Service Electric and Gas Company | 3.15 | Fixed | Aug-06-2014 | 250.0 | BBB+ | 10 |
| 61 | Jun-01-2044 | Public Service Electric and Gas Company | 4.0 | Fixed | May-28-2014 | 250.0 | BBB+ | 30 |

# Electric Transmission Co. Debt Issuances

| | Maturity Date | Issuer | Coupon Rate (%) | Coupon Type | Offering Date | Offering Amount ($mm) | Issuer Credit Rating | Term |
|---|---|---|---|---|---|---|---|---|
| 62 | Sep-01-2019 | Southern Company (NYSE:SO) | 2.15 | Fixed | Aug-19-2014 | 350.0 | A | 5 |
| 63 | Jun-15-2024 | Southwestern Public Service Company | 3.3 | Fixed | Jun-02-2014 | 150.0 | A- | 10 |
| 64 | May-15-2044 | Tampa Electric Company | 4.35 | Fixed | May-12-2014 | 300.0 | BBB+ | 30 |
| 65 | Apr-01-2043 | Texas-New Mexico Power Company | 6.95 | Fixed | Apr-02-2014 | 93.2 | BBB | 29 |
| 66 | Apr-15-2044 | The Connecticut Light and Power Company | 4.3 | Fixed | Apr-14-2014 | 250.0 | A- | 30 |
| 67 | Jun-01-2025 | Trans-Allegheny Interstate Line Company | 3.85 | Fixed | Dec-08-2014 | 550.0 | BBB- | 10 |
| 68 | Mar-15-2044 | Tucson Electric Power Company | 5.0 | Fixed | Mar-05-2014 | 150.0 | BBB+ | 30 |
| 69 | Apr-15-2024 | Union Electric Company | 3.5 | Fixed | Apr-01-2014 | 350.0 | BBB+ | 10 |
| 70 | Feb-15-2024 | Virginia Electric and Power Company | 3.45 | Fixed | Feb-04-2014 | 350.0 | A- | 10 |
| 71 | Feb-15-2044 | Virginia Electric and Power Company | 4.45 | Fixed | Feb-04-2014 | 400.0 | A- | 30 |
| | Average | | **3.90** | | | **312.1** | | |

FERC Case # ER 15-572

| | TOTS Project Cost | Equity Ratio | Debt Ratio | ROE[2] | Cost of debt[1] | PTROR | Total Rev. Req'ment (First 16 yrs-$m) | Total Rev. Req'ment (Full 40 yrs-$m) |
|---|---|---|---|---|---|---|---|---|
| | **REVENUE REQUIREMENT PER NY TRANSCO FERC FILING** | | | | | | | |
| MSSC Project | $66,000,000 | 60% | 40% | 11.63% | 4.30% | 13.20% | $223.5 | $441.4 |
| Ramapo - Rock Tavern | $121,000,000 | 60% | 40% | 11.63% | 4.30% | 13.20% | $367.4 | $731.3 |
| Staten Island Unbottling | $262,000,000 | 60% | 40% | 11.63% | 4.30% | 13.20% | $747.0 | $1,494.3 |
| **Total** | **$449,000,000** | | | | | | $1,338 | **$2,667.0** |
| | **REVENUE REQUIREMENT PER PSC IPEC ORDER** | | | | | | | |
| MSSC Project less NYPA Share[3] | $36,000,000 | 48% | 52% | 8.70% | 3.60% | 8.80% | $91.8 | $195.5 |
| Ramapo - Rock Tavern | $123,100,000 | 48% | 52% | 8.70% | 3.60% | 8.80% | $313.8 | $668.5 |
| Staten Island Unbottling | $248,000,000 | 48% | 52% | 8.70% | 3.60% | 8.80% | $632.3 | $1,346.7 |
| **Total** | **$407,100,000** | | | | | | $1,038 | **$2,210.6** |
| | **DIFFERENCES IN REVENUE REQUIREMENTS(NY TRANSCO FERC FILING vs. IPEC)** | | | | | | | |
| MSSC Project | $30,000,000 | 12.00% | -12.00% | 2.93% | 0.70% | 4.40% | $131.7 | $245.9 |
| Ramapo - Rock Tavern | ($2,100,000) | 12.00% | -12.00% | 2.93% | 0.70% | 4.40% | $53.5 | $62.8 |
| Staten Island Unbottling | $14,000,000 | 12.00% | -12.00% | 2.93% | 0.70% | 4.40% | $114.7 | $147.6 |
| **Total** | $41,900,000 | | | | | | **$300** | **$456.3** |

Comments

1 4.30%=Average rate for "AA","A","BBB" public utility debt as of December 2014 (per Mergent Bond Record) plus 10 bps for issuance

3.60%=As used by Staff in determining the Net Present Value in the IPEC Order.

2 11.63% Requested ROE=NY Transco's upper limit of zone of reasonableness

3 MSSC project cost of $76 million modified to remove NYPA's share of $40 million