# AC Transmission Public Policy Transmission Planning Report Addendum

A Report by the
New York Independent System Operator

DRAFT

December 27, 2018

# Table of Contents

## Executive Summary for Addendum

NYISO staff submitted the draft AC Transmission Public Policy Transmission Planning Report ("Draft Report") to the NYISO Board of Directors ("Board") for its review and action. The Draft Report summarized NYISO staff's analysis and recommendations concerning proposed solutions to address the AC Transmission Public Policy Transmission Needs identified by the New York Public Service Commission ("PSC"), which includes the need to increase Central East transfer capability by at least 350 MW ("Segment A") and UPNY/SENY transfer capability by at least 900 MW ("Segment B").

In the Draft Report, NYISO staff recommended that the Board select as the more efficient or cost effective solution to address the AC Transmission Needs the Segment A project (T027) proposed jointly by North American Transmission ("NAT") and New York Power Authority ("NYPA") and the Segment B project (T029) also proposed by NAT and NYPA.

The Board provided interested parties with the opportunity to submit comments and to make oral presentations for the Board's consideration prior to its taking action concerning the Draft Report. Based on this input and the Board's independent review of the Draft Report, the Board directed NYISO staff to conduct certain additional studies and analyses.

The Board proposes to modify the Draft Report to reflect the results of the additional studies and analyses as well as the Board's conclusions regarding certain information provided in the Draft Report. These modifications are contained in this Addendum to the Draft Report ("Revised Report"). As described in the Board memorandum, the Board has determined that the more efficient or cost effective solution for Segment A is project T027. The Board also concluded that for Segment B, the more efficient or cost effective solution is project T019, which was jointly proposed by Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid") and the New York Transco, LLC ("Transco"). Based on the estimated project schedules, the in-service date established for the purposes of the Development Agreements for the selected projects is December 2023.

After conducting additional analyses at the Board's request, considering the import of those analyses in conjunction with information in the Draft Report, NYISO staff supports the Board's project selections for both Segments A and B.

In accordance with the NYISO's tariff, the Revised Report will be returned to the Management Committee for further comment. Following the Board's consideration of these comments, the Board will make its final determination on the Revised Report and the selection of the Public Policy Transmission Projects to address the AC Transmission Needs.

# 1. Transfer Limit Analysis

Transfer limit analysis evaluates the amount of power that can be transferred across a defined transmission interface while observing applicable reliability criteria. The results of transfer limit analysis are used in the evaluation of metrics such as Cost per MW, Operability, and Performance, as well as for determining ICAP benefits.

As described in Section 3.2.1 of the Draft Report, the NYISO evaluated the transfer limits of the UPNY/SENY interface based on the criteria set forth by the NYPSC Order for Segment B. The UPNY/SENY interface is critical to the New York State transmission system as it represents the collection of transmission lines on which all power flows from Upstate New York to Southeast New York. UPNY/SENY is historically limited by the thermal capability of the individual transmission lines; therefore, the NYISO performed various thermal transfer analysis.

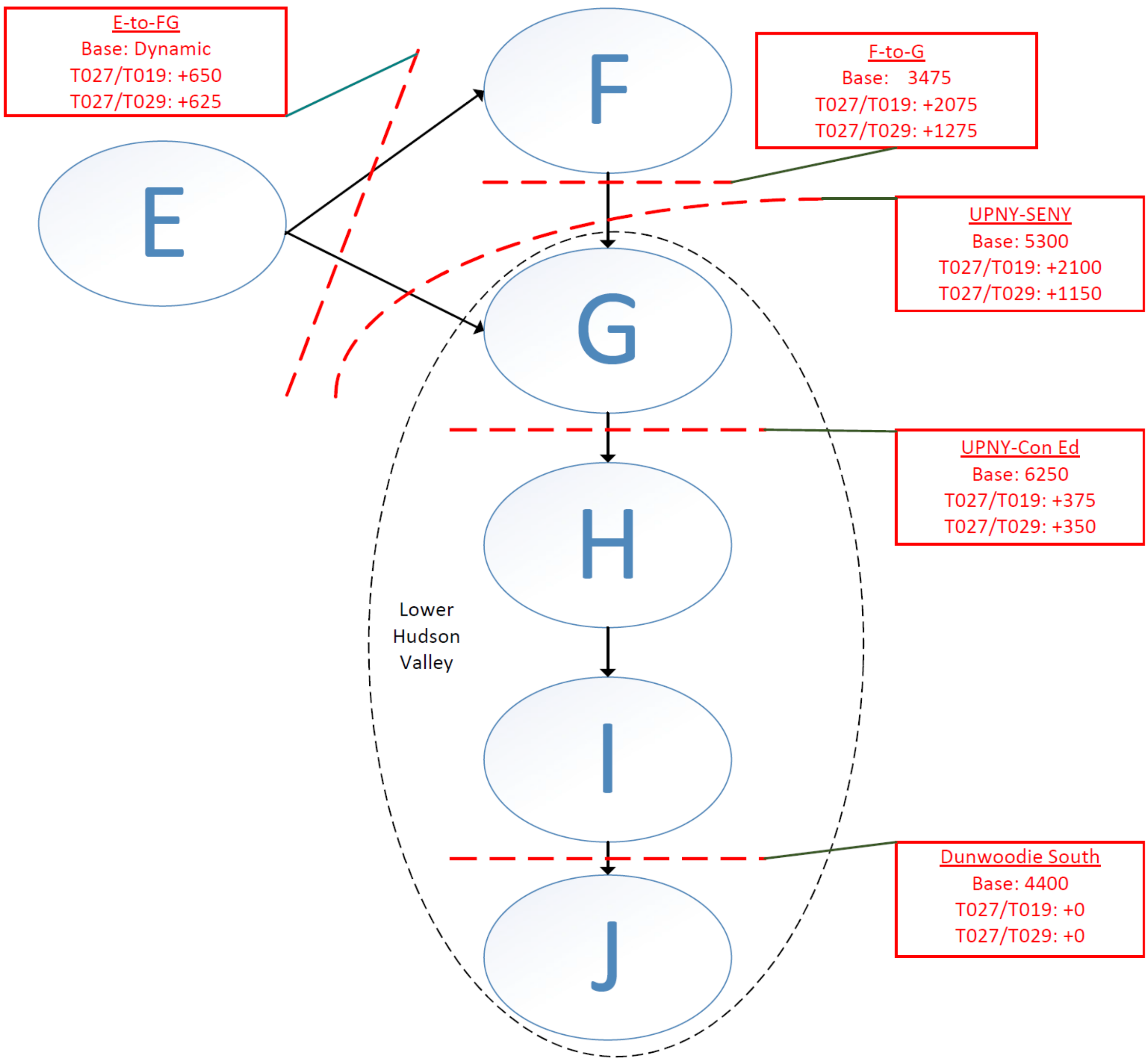
The Board identified aspects of the transfer limit methodologies and results that warranted further scrutiny, and therefore requested additional analysis to assess whether and, if so, how alternate approaches should be factored in the selection process. This section describes additional transfer analysis based on the 2016 Reliability Planning Process power flow case with the updates detailed in Section 3.2.1 of the Draft Report.

## 1.1. UPNY/SENY Transfer Limits for N-1 Emergency Transfer Criteria

The calculation of Emergency Transfer Limits is necessary to support a number of the requests from the Board further described in this Addendum. Emergency Transfer Criteria are defined by the New York State Reliability Council to allow transfers to be increased up to higher short-term emergency (15-minute) ratings for post-contingency conditions. Emergency Transfer Criteria may be invoked in the event that adequate facilities are not available to supply firm load within Normal Transfer Criteria. The use of Emergency Transfer Criteria is critically important for the operation of the New York bulk power system in that it allows the transmission system to be operated to higher ratings during emergency or stressed system conditions in order to supply firm load and to avoid the need for load relief measures. Therefore, Emergency Transfer Criteria limits are utilized in resource adequacy analysis, including the evaluation of loss of load expectation (LOLE) for system planning and the calculation of the Installed Reserve Margin (IRM) and Locational Capacity Requirements (LCRs) for the capacity market.

Figure A-1 depicts the N-1 Emergency Transfer Criteria limits for the T019 project and the T029 project assuming that T027 is the project selected for Segment A. The additional emergency transfer capability of 950 MW provided by the T019 project relative to the other Segment B projects constitutes a material benefit to the operability and performance of the transmission system and capacity savings for the market as described in Sections 3, 4, and 6 of this Addendum.

**Figure A-1: Incremental UPNY/SENY N-1 Emergency Transfer Capability**




* T027/T029 is representative of all other Segment B projects

## 1.2. Alternate Dispatch Methodology to Determine Transfer Limits

Transfer limits can be highly sensitive to generation dispatch depending on the transmission project design. To derive the original incremental UPNY/SENY N-1-1 thermal transfer capability shown in Table 3-18 of the Draft Report, certain Capital Zone (Zone F) and Hudson Valley Zone (Zone G) generators were restricted to be dispatchable only within a small range.[1] This small range is to mimic the typical dispatch in resource adequacy reliability models.

As requested by the Board, the NYISO staff evaluated the impact of generation dispatch on the N-1-1 transfer capability by utilizing the dispatch methodology established for calculating transmission security-based floors used by the Alternative Locality Capacity Requirement (LCR) optimization process. As part of the calculation of LCRs, a Transmission Security Limit (TSL) is calculated for the Zones G-J, the Zone J, and the Zone K Localities to represent the N-1-1 transmission transfer capability into each locality. Each TSL is then used to calculate a percentage floor for each LCR. Each LCR floor is then input to the optimizer simulation to prevent the optimizer from reducing the capacity below adequate levels for each locality.

The assumptions for calculating the LCR TSLs recognize that: (1) in actual operations the NYISO can re-dispatch a reasonable amount of generation in support of increasing the transmission security limits, and (2) the NYISO should expect to meet transmission security limits by procuring the required amount of ICAP resources within each of the localities in order for the NYISO to be capable of operating the New York State transmission system in the Normal Transfer Criteria state.[2] As such, the following assumptions are used:

a) Individual generators are limited in re-dispatch between a minimum of 50% and a maximum of 100% of their Dependable Maximum Net Capability ("DMNC") value. The minimum DMNC value of 50% represents an average level of physical minimum generation levels.

b) All applicable NERC, NPCC, and NYSRC contingencies under N-1-1 design criteria for Normal Transfer Criteria are evaluated. The transfer level associated with the most limiting N-1-1 contingency combination is the TSL.

[1] Athens: 970-1000 MW, Gilboa: 565-585 MW, Cricket Valley: 1010-1050 MW, CPV Valley: 650-680 MW, Danskammer: 200-230 MW, Roseton: 554-584 MW, and Bowline: 547-577 MW.

[2] Normal Transfer Criteria, as defined by the New York State Reliability Council, require that pre-contingency circuit loading is within normal (24-hour) ratings and post-contingency circuit loading is within applicable emergency (typically 4-hour) ratings for all design criteria contingencies. Design criteria contingencies include multiple-element contingencies such as stuck breakers and double-circuit towers.

#### 1.2.1. Revised UPNY/SENY Transfer Limits for Normal Transfer Criteria

Applying the Alternate Dispatch (LCR TSL) methodology, Table A-1 shows the UPNY/SENY Normal Transfer Criteria transfer limits under various outage conditions (N-1 and N-1-1) for the pre-project case and the post-project cases for each Segment B project in combination with the NAT/NYPA T027 Segment A project. The UPNY/SENY TSL for each case is highlighted in red.

**Table A-1: UPNY/SENY Normal Transfer Criteria Limits**

| Maintenance Outage | No Outage | CPV - Rock Tavern 345 kV Line | Marcy - Coopers Corners 345 kV Line | Roseton - East Fishkill 345 kV Line | Athens-Pleasant Valley 345 kV Line | Knickerbocker-Pleasant Valley 345 kV Line |
|---|---|---|---|---|---|---|
| Pre-Project | 5,050 | 4,450 | 4,425 | 3,975 | 3,450 | - |
| T027+T019 | 7,150 | 6,600 | 6,450 | 5,325 | 4,875 | 4,725 |
| T027+T022 | 6,650 | 6,050 | 6,025 | 5,000 | 4,750 | 4,775 |
| T027+T023 | 6,600 | 6,025 | 5,975 | 4,975 | 4,700 | 4,725 |
| T027+T029 | 6,525 | 5,900 | 5,875 | 5,350 | 4,650 | 4,725 |
| T027+T030 | 6,650 | 6,175 | 6,025 | 5,475 | 4,775 | 4,725 |
| T027+T032 | 6,575 | 6,000 | 5,900 | 4,975 | 4,675 | 4,775 |

The Draft Report addresses the N-1-1 limits in Section 3.3.5.2 and in Table 3-18. The results shown above using the alternate dispatch methodology indicate that, for all projects, the minimum N-1-1 Normal Transfer Criteria limits for the UPNY/SENY interface range from 4,650 MW to 4,750 MW. These findings indicate that the UPNY/SENY N-1-1 Normal Transfer Criteria limits are not a distinguishing factor among the proposed projects. Section 2 further describes the cost-per-MW metric that utilizes the "no outage" (*i.e.,* N-1) results.

#### 1.2.2. Revised UPNY/SENY Transfer Limits for N-1-1 Emergency Transfer Criteria

Applying the Alternate Dispatch (LCR TSL) methodology, Table A-2 shows the UPNY/SENY N-1-1 Emergency Transfer Criteria transfer limits for the pre-project case and the post-project cases for each proposed Segment B project in combination with the NAT/NYPA T027 Segment A project. The lowest limit for each project is highlighted in red.

**Table A-2: UPNY/SENY Emergency Transfer Criteria N-1-1 Limits**

| Maintenance Outage | CPV - Rock Tavern 345 kV Line | Marcy - Coopers Corners 345 kV Line | Roseton - East Fishkill 345 kV Line | Athens-Pleasant Valley 345 kV Line | Knickerbocker-Pleasant Valley 345 kV Line |
|---|---|---|---|---|---|
| Pre-Project | 4,850 | 5,025 | 4,500 | 3,900 | - |
| T027+T019 | 7,275 | 6,950 | 6,975 | 5,675 | 5,425 |
| T027+T022 | 6,725 | 6,450 | 6,150 | 5,375 | 5,475 |
| T027+T023 | 6,725 | 6,400 | 6,100 | 5,350 | 5,425 |
| T027+T029 | 6,625 | 6,350 | 6,000 | 5,250 | 5,425 |
| T027+T030 | 6,775 | 6,475 | 6,175 | 5,400 | 5,425 |
| T027+T032 | 6,700 | 6,400 | 6,125 | 5,300 | 5,475 |

The results indicate that, for all projects, the N-1-1 Emergency Transfer Criteria limits for the UPNY/SENY interface range from 5,250 MW to 5,425 MW using the alternate generation dispatch methodology. These findings indicate that the UPNY/SENY N-1-1 Emergency Transfer Criteria limits are not a distinguishing factor among the proposed projects.

## 2. Cost per MW

As reflected in Section 3.3.3 of the Draft Report, the NYISO calculated the Cost per MW ratio metric by dividing the independent cost estimates, provided by the NYISO independent consultant Substation Engineering Company (SECO), for Segment B by the incremental MW value of transfer capability. Given the revised transfer limits calculated at the request of the Board, as discussed above, the NYISO staff recalculated the Cost per MW ratio metric. The incremental increase for UPNY/SENY is based on the revised "no outage" (N-1) Normal Transfer Criteria transfer limits described in Section 1.2.1 of this addendum.

Table A-3 reports the Cost per MW ($M/MW) ratio based on the updated transfer limits.

**Table A-3: Cost per MW Ratio**

| Project | Segment B Independent Cost Estimate (2018 $M) | Incremental UPNY/SENY (MW) | **Cost per MW** |
|---|---|---|---|
| T027+T019 | $479 | 2,100 | **0.228** |
| T027+T022 | $373 | 1,600 | **0.233** |
| T027+T023 | $424 | 1,550 | **0.274** |
| T027+T029 | $422 | 1,475 | **0.286** |
| T027+T030 | $441 | 1,600 | **0.276** |
| T027+T032 | $536 | 1,525 | **0.351** |

The results show that T019 has the lowest Cost per MW ratio of all the Segment B projects.

# 3. Operability

As reflected in Section 3.3.5 of the Draft Report, the NYISO considered how the proposed Public Policy Transmission Projects affect flexibility in operating the system, such as dispatch of generation, access to operating reserves, access to ancillary services, or the ability to remove transmission facilities for maintenance. The NYISO also considered how the proposed projects may affect the cost of operating the system, such as how they may affect the need for operating generation out of merit for reliability needs, reduce the need to cycle generation, or provide more balance in the system to respond to system conditions that are more severe than design conditions.

The Board requested the NYISO staff to further examine how certain design aspects of the proposed projects could be beneficial to the future operation of the grid under more extreme conditions such as high impact storms or significant generation retirements that could otherwise strain the system. This section describes additional assessments of resilience, generator deactivations, and operating reserve.

## 3.1. Resilience Benefits

The resilience of the electric power system is an important consideration in evaluating the operability of proposed transmission projects. FERC has proposed a working definition of resilience as "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."

A meaningful measure of grid resilience is the ability of New York State's electric power system to withstand extreme storm events. The power system in New York is a collection of individual components that includes high voltage transmission lines, generation resources, and important substation equipment. The resilience of the New York State's power system is dependent, in part, on each individual facility component's ability to "withstand the disruptive event." It is sometimes difficult to clearly assess the resilience benefits of an individual facility component's system design, but it is reasonable to invest in incremental improvements above minimally accepted criteria in order to protect the system from the potential catastrophic events.

With a focus on New York State's transmission system resilience, there have been occurrences of extreme disruptive storm events, which have included hurricanes, tornados, windstorms, coastal flooding, and ice storms. As an example, an ice storm in January 1998 was particularly impactful, in which a series of storms swept across the northeastern part of North America, causing 770 transmission structures to collapse.[3] About 110,000 customers were affected in northeastern New York due to the loss of 230 kV and 115 kV lines in this area, and major tie lines with neighboring systems were lost for several weeks.

#### 3.1.1. Transmission Line Structural Design

SECO evaluated the transmission line structural design for all of the proposals relative to the ice and wind loading requirements defined by the National Electric Safety Code (NESC).[4]

All proposals meet minimum NESC standards, but the National Grid/Transco T019 Segment B proposal includes heavier duty structures mounted on drilled-shaft concrete foundations where other proposals use direct embedded poles with crushed rock backfill foundations for tangent pole applications (shown in Figure A-2 and Figure A-3). The concrete foundations of T019 cost approximately two and a half times as much compared to the direct embedded rock foundations, but provide greater resilience to significantly heavier wind and ice loadings. In addition, T019 utilizes more dead-end structures compared to the other Segment B proposals, with an average distance of approximately one mile between dead-end structures. This more resilient design would mitigate cascading structure failures if they occur.

**Figure A-2: Drilled Shaft Construction**

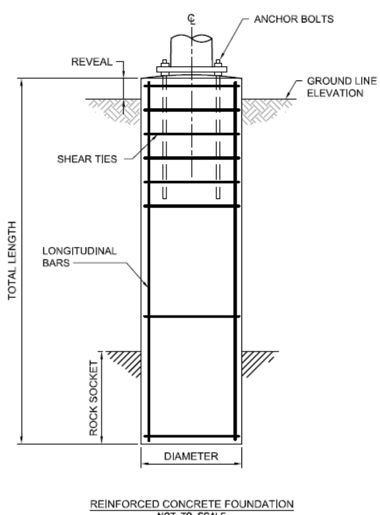
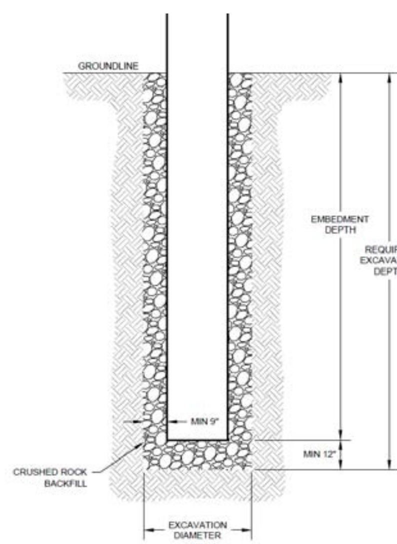



**Figure A-3: Direct Embedded Pole Construction**




---

3 NERC 1998 System Disturbances Report: https://www.nerc.com/pa/rrm/ea/System%20Disturbance%20Reports%20DL/1998SystemDisturbance.pdf

4 SECO Report Section 4.11.2.7

NextEra's T022/T023 project design proposes to install full length concrete poles as opposed to the multi-piece steel poles proposed by other developers. This design also provides greater resilience to ice loading, but the direct embedded foundations proposed by NextEra result in lesser resilience to wind than T019. There is also significantly more incremental work involved in the installation of full length concrete poles as opposed to multi-piece steel poles. For example, there would be additional labor required to rig and set concrete poles which could have length up to 135 feet and weigh up to 62,000 pounds. By contrast, steel poles are constructed in segments, typically with three segments no longer than 50 feet each, and weighing up to 16,000 pounds.

While the costs of the enhanced structures for projects T019 and T022/T023 are higher, it is important to appropriately recognize the incremental resilience benefit to withstand reasonable icing and wind events. The Board has concluded that this benefit should be more prominently reflected in the Operability metric and project ranking.

#### 3.1.2. Resilience Benefits of Increased Transmission Capability

The NYISO has long advocated that maintaining and improving transmission capability within New York State will improve the reliability and resilience of the transmission grid during stressed system conditions and disruptive events. Stressed conditions and disruptive events can occur because of many different factors; examples include extreme storm conditions (*e.g.*, Superstorm Sandy) which can result in a large number of bulk electric system transmission outages or during events when critical supply resources are forced out of service or otherwise unavailable (e.g. fuel shortage events).

Maintaining and improving electric transmission system capability is generally viewed as supportive of promoting grid resilience. In comments responsive to the FERC resilience docket, the NYISO stressed the importance of maintaining and protecting existing interconnections between neighboring systems, as well as continually assessing opportunities to improve interregional transaction coordination serves to bolster resilience throughout an interconnected region. These interconnections foster the opportunity to rely on a broader, more diverse set of resources to meet the overall needs of an interconnected region. The more diverse resource pool available through interregional interconnections provides both economic and resilience benefits, especially during stressed operating conditions such as sustained heat waves or cold snaps.

In New York, there are a limited number of transmission corridors available to build new transmission projects in support of improving the state's transmission capability. Given the limited potential for new transmission projects in the future, the additional 950 MW of emergency transfer capability provided by the T019 project would materially improve the transmission system into the Southeast New York area. The Board has concluded that the additional transfer capability provided by T019 should be reflected as a benefit in the Operability metric and in the project ranking.

### 3.2. Ability to Accommodate Generator Deactivations

The Board requested further evaluation of how the increase in UPNY/SENY transfer capability resulting from the Segment B projects could accommodate additional generation deactivations within the Lower Hudson Valley, if they occur, while maintaining reliability. As part of each Reliability Needs Assessment, the NYISO performs a "zonal capacity at risk" scenario. The zonal capacity at risk assessment identifies a maximum level of capacity in megawatts that can be removed from a given zone without causing loss of load expectation (LOLE) reliability criterion violations.[5] A small megawatt amount is indicative of a transmission constrained zone that is reliant upon intra-zonal generation, while a large megawatt amount is indicative of a zone that has a significant import capability and/or significant surplus generation. Accordingly, the NYISO performed this analysis for the National Grid/Transco T019 project and the NAT/NYPA T029 project, each in combination with the NAT/NYPA T027 Segment A project, to determine for each project how much generation could deactivate within Zone G while maintaining reliability under the postulated future system conditions. The T029 project results are also representative of other Segment B projects with the exception of T019. Table A-4 summarizes the results:

**Table A-4: Maximum MW Capacity Removal from Zone G in 2030**

| Project | Baseline Case | CES+Retirement Scenario |
|---|---|---|
| T027+T019 | 1,400 | 2,900 |
| T027+T029 | 1,400 | 2,100 |

Under both the baseline case and the CES+Retirement scenario system conditions, the UPNY/SENY interface is not a binding constraint before removal of generation, even without the AC Transmission projects. This means that the UPNY/SENY interface limit does not affect the resource adequacy of the system before removal of generation from Zone G. By comparison, the UPNY/ConEd interface is the most binding in the system for resource adequacy under all study conditions before removal of generation. This means that the additional UPNY/ConEd transfer capability provided by each Segment B project is beneficial to the resource adequacy of the system. As discussed in Section

[5] The megawatt amounts are reported as "perfect capacity", which is capacity that is not derated (e.g., due to ambient temperature or unit unavailability) and not tested for impacts to interface limits.

4, the Performance metric also recognizes the potential benefits of future system improvements that could be made to mitigate the impact of voltage limitations of the UPNY/ConEd interface.

For the baseline case, in which there are not significant generation projects added upstate, there is not enough surplus generation upstate to serve the Zone G load once 1,400 MW of generation is removed from Zone G. At that point, the LOLE violation occurs before the UPNY/SENY interface becomes binding. Therefore, there is no additional resource adequacy benefit for Zone G that would be realized from additional UPNY/SENY transfer capability under baseline system conditions.

For the CES+Retirement scenario, there are three primary differences in system conditions compared to the baseline: (1) additional energy efficiency measures equating to a peak load decrease of approximately 2,300 MW statewide in 2030, (2) additional renewable generation primarily located upstate (see details in Table 3-4 of the Draft Report), and (3) the retirement of all coal generation and approximately 3,500 MW of older gas turbines in New York City and Long Island. Under these postulated system conditions, more capacity can be removed from Zone G compared with the baseline analysis because of the reduced peak load and additional renewables, particularly an additional 1,000 MW of utility-scale solar in Zone G. When removing capacity from Zone G with the AC Transmission projects in place, the UPNY/SENY interface begins to bind at a certain point because of the flow of power from the additional renewables upstate, and therefore additional UPNY/SENY transfer capability could be beneficial if a large number of generator retirements were to occur in Zone G.

In summary, an increase to the UPNY/SENY transfer limit does not provide an improvement in resource adequacy under the baseline system conditions which assumes no generation retirements occur, but such additional capability would be beneficial under the CES+Retirement scenario system conditions if Zone G generator retirements were to exceed approximately 2,100 MW. This analysis would indicate a benefit to the T019 project in a future scenario where the New York system is impacted by large upstate renewable additions and the potential for Zone G generation retirements. The Board concluded that this benefit should be reflected as a benefit in the Operability metric and in the project ranking.

### 3.3. Impact on SENY 30-Minute Reserve Requirement

In calculating the revised transfer limits at the request of the Board, as discussed above, the potential impact of these transfer limits on the locational reserve requirement for Southeast New York (SENY) was evaluated. For the calculation of the SENY locational reserve requirement, limits for the UPNY/SENY transfer capability need to be determined under both N-1-1 and N-1 criteria as follows:

a) For the N-1 criteria UPNY/SENY limit, all applicable NERC, NPCC, and NYSRC contingencies assuming Normal Transfer Criteria are used.

b) For the N-1-1 criteria UPNY/SENY limit, all applicable NERC, NPCC, and NYSRC contingencies assuming Emergency Transfer Criteria are used.

c) Individual generators are limited in re-dispatch between a minimum of 50% and a maximum of 100% of their DMNC value.

d) The difference between these N-1 and N-1-1 UPNY/SENY limits represents the expected level of locational operating reserves needed for the SENY locality that would have to be procured in the NYISO day-ahead and real-time energy and ancillary services markets.

This analysis was performed for the Segment B projects, each in combination with the NAT/NYPA T027 Segment A project, with the results shown in Table A-5.

**Table A-5: SENY Reserve Requirement**

| Project | N-1 Normal | N-1-1 Emergency | Reserve Requirement |
|---|---|---|---|
| Pre-Project | 5,050 | 3,900 | 1,150 |
| T027+T019 | 7,150 | 5,425 | 1,725 |
| T027+T022 | 6,650 | 5,375 | 1,275 |
| T027+T023 | 6,600 | 5,350 | 1,250 |
| T027+T029 | 6,525 | 5,250 | 1,275 |
| T027+T030 | 6,650 | 5,400 | 1,250 |
| T027+T032 | 6,575 | 5,300 | 1,275 |

The present-day Southeast New York (SENY) locational reserve requirement is 1,300 MW. The pre-project result from this analysis is 150 MW less, which can be attributed to various differences in the system model such as the addition of Cricket Valley and the retirement of the Athens special protection system.

The analysis demonstrates that every Segment B project would result in some level of increase in the SENY reserve requirement, but the National Grid/Transco T019 project would require approximately 450 MW of additional 30-minute reserves compared to other Segment B projects. The T019 project provides a higher normal transfer limit with all lines in (N-1) compared to the other projects, but maintains approximately the same emergency transfer limit under the critical outage (N-1-1), thus necessitating a greater amount of generation redispatch to transition from an N-1 normal state to an N-1-1 emergency state.

The New York Control Area total 30 minute reserve requirement of 2,620 MW would not change as a result of the transmission projects. Given that reserve suppliers located in SENY typically provide the majority of the New York Control Area reserve requirement of 2,620 MW, the 450 MW increase in SENY locational reserve requirement associated with the T019 project is not expected to be impactful.

# 4. Performance

The Board requested NYISO staff investigate whether there are potential performance benefits associated with the series compensation capability included with T019. NYISO staff provided the Board with information related to how the proposed series compensation can provide certain operational benefits from improved utilization of the UPNY/SENY interface through NYISO actions directing the operational status of the series compensation. Specifically, the NYISO can direct the proposed series compensation to be switched in or out of service in response to reliability or market conditions.

The NYISO has realized similar performance benefits, both from a grid reliability and energy market operations perspective, by directing the operational status of the existing series compensation on the Marcy-South transmission corridor during certain transmission outage scenarios and during the different seasonal market operating conditions.

As an example, in the fall of 2017, the NYISO implemented operational actions using the operational control provided by the Marcy-South series compensation in response to observed seasonal market operating conditions:

a) During the Summer Capability Period, the Marcy-South Series Capacitors will normally remain in service to facilitate improved utilization of the New York transmission system. This action increases the UPNY/SENY transfer capability, which tends to reduce UPNY/SENY congestion that is typically more limiting than other transmission system constraints.

b) During the Winter Capability Period, the Marcy-South Series Capacitors will normally be out of service (bypassed) to facilitate improved utilization of the New York transmission system. This action increases the Central-East transfer capability, which tends to reduce Central-East congestion that is typically more limiting than other transmission system constraints.

In a manner similar to the current use of the Marcy-South series compensation, the NYISO expects that operational benefits will be realized by the capability to control Segment B power flows by directing the operational status of the series compensation for T019.

The improved controllability of UPNY/SENY power flows by the T019 project will allow the NYISO more flexibility in addressing grid reliability needs, and can result in improved utilization of the overall transmission system as compared to the other proposed projects. This operational capability is expected to result in lower overall energy costs and provide benefit to consumers during certain transmission outage conditions or under certain market operating conditions. Furthermore, the utilization of the UPNY/ConEd interface could be further increased if future system improvements mitigate the voltage limitations. Voltage limitations can potentially be addressed in a variety of ways without needing to build additional transmission lines.

The Board has concluded that T019's improved control of power flows and increased utilization of the UPNY/SENY interface should be reflected as a benefit in the Performance metric and in the project ranking.

# 5. Production Cost

As reflected in Section 3.3.7 of the Draft Report, the NYISO calculated the system production cost savings that could be realized for the proposed projects. The savings for each project is calculated as the difference between the pre-project and post-project results over the duration of a project's study period. The study period begins with the estimated in-service date and extends 20 years. Entries with a dollar value are listed in 2018 millions of dollars. The discount rate used to calculate present value is 6.988% consistent with the 2017 CARIS Phase 1 database. The NYISO used scenarios to distinguish projects and to measure the robustness of project performance.

The Board requested additional production cost analysis to study the potential impact of incorporating carbon pricing in the NYISO's wholesale market on the relative cost effectiveness of Segment B projects.

## 5.1. Social Cost of Carbon Sensitivity

The additional simulations were performed using the CES+Retirement case with $CO_2$ emissions priced at the social cost of carbon as defined by the New York State Department of Public Service (DPS). Each of the project proposals were modeled in combination with the NAT/NYPA T027 Segment A project. Two sets of simulations were conducted, one set for T019 because the project is electrically distinct from other Segment B projects, and the second set for T029 since it is electrically comparable to T022, T023, and T032.[6]

The methodology and carbon costs employed in this analysis mirror those being utilized in the carbon pricing market designs that are being discussed at NYISO's Integration Public Policy Task Force (IPPTF). As in the Brattle work for IPPTF, hourly external transactions (MWh) with neighboring control areas (*e.g.*, PJM, ISO-NE) from the relevant base case are frozen or locked in the social cost of carbon cases, consistent with NYISO's Carbon Pricing Straw Proposal. This is to make the economics of external generator dispatch and transactions unaffected by a carbon adder. Absent this, there would be a material increase in imports because New York generation, with its market offers now including a carbon adder, would become appreciably more expensive than external resources.

---

[6] Simulations were not performed for T030 because in all CES+Retirement cases it underperforms T029 in production cost savings.

This "freezing of external transactions" was effected in the production cost modeling by running cases without the social cost of carbon and then locking the hourly interface flows (within a +/- 20 MW bandwidth) when running the case with the social cost of carbon. For example, for the CES+Retirement case, the NYISO ran the 20-year simulation and extracted the hourly interface flows. The NYISO then modeled these interface flows in its production cost simulation (allowing the flows to be 20 MW higher or lower), incorporated the social cost of carbon, and then re-ran the case.

The NYISO utilized the social cost of carbon assumed in the IPPTF analysis for study years 2023-2030, and escalated these values by four percent annually for study years 2031-2042. Table A-6 presents the assumed costs in $ per ton of $CO_2$:

**Table A-6: Social Cost of Carbon Assumptions**

| Year | Social Cost of Carbon (nominal, $/ton) | Year | Social Cost of Carbon (nominal, $/ton) | Year | Social Cost of Carbon (nominal, $/ton) |
|---|---|---|---|---|---|
| 2023 | $52.74 | 2030 | $69.32 | 2037 | $91.22 |
| 2024 | $55.07 | 2031 | $72.09 | 2038 | $94.87 |
| 2025 | $57.48 | 2032 | $74.98 | 2039 | $98.66 |
| 2026 | $59.96 | 2033 | $77.98 | 2040 | $102.61 |
| 2027 | $62.52 | 2034 | $81.09 | 2041 | $106.71 |
| 2028 | $65.17 | 2035 | $84.34 | 2042 | $110.98 |
| 2029 | $66.54 | 2036 | $87.71 | | |

Total production costs for the New York Control Area (NYCA) consist of internal NYCA generation costs and the net cost of transactions with New York's neighbors. Internal generation costs are comprised of fuel, variable operation and maintenance, start-up and emission allowance costs for SOx, NOx, and $CO_2$.[7]

Savings associated with carbon-related production costs were substantially higher for both T019 and T029 in the social cost of carbon case as one would expect due to the higher per-ton costs. However, as illustrated, these incremental savings were attenuated due to reduced savings in fuel and variable operation and maintenance costs for both T019 and T029. These off-setting effects can be attributed to changes in the pattern of inter-control area flows, and to differences in the New York commitment and dispatch between the original, RGGI-only cases and the social cost of carbon case.

The overall production cost savings for T019 compared with the pre-project case increases by

[7] SOx and NOx costs are negligible relative to the other components of production costs and are therefore not discussed further.

$124M as a result of including the social cost of carbon. This includes a decrease of $237M in carbon-related costs, an increase of $72M in fuel and variable operation and maintenance, a decrease of $7M in start-up costs, and an increase of $49M in costs related to the net interchange with neighboring control areas.

The overall production cost savings for T029 increases by $121M compared with the pre-project case as a result of including the social cost of carbon. This increase can be disaggregated into a decrease in carbon-related costs of $221M, an increase in fuel and variable operation and maintenance costs of $60M, a decrease in start-up costs of $8M, and an increase in costs related to the net interchange of $48M.

Table A-7 summarizes the results for the original case and the updated, social cost of carbon case.

**Table A-7: Production Cost Savings**

| CES+ Retirement Scenario | Capital Costs | Original RGGI Program Only | | Social Cost of Carbon Sensitivity | |
|---|---|---|---|---|---|
| | | Production Cost Savings | Production Cost Savings / Capital Costs | Production Cost Savings | Production Cost Savings / Capital Costs |
| T027+T019 | $1,230 | $1,179 | 0.959 | $1,303 | 1.059 |
| T027+T022 | $1,123 | $1,129 | 1.005 | $1,250 | 1.113 |
| T027+T023 | $1,174 | $1,129 | 0.962 | $1,250 | 1.065 |
| T027+T029 | $1,113 | $1,129 | 1.014 | $1,250 | 1.123 |
| T027+T030 | $1,131 | $1,108 | 0.980 | N/A | N/A |
| T027+T032 | $1,286 | $1,129 | 0.878 | $1,250 | 0.972 |

In summary, this analysis shows that while there were incremental increases in the production cost savings for both studied projects (and by extension, all relevant Segment B projects), the inclusion of the social cost of carbon did not alter the comparative system costs of projects with regard to production cost savings to capital cost ratio.

# 6. ICAP Benefits

The Board asked NYISO staff to update and conduct further analysis to evaluate whether particular projects are likely to produce additional Installed Capacity ("ICAP") cost savings relative to the other proposed projects. As more fully described in Section 3.3.8 of the Draft Report and summarized below, the original analysis relied upon the optimization tool developed by the NYISO to set optimal locational capacity requirements (LCRs) for use in its capacity markets. While the prior methodology to calculate ICAP benefits was not materially altered, the NYISO did incorporate additional constraints to the optimization (*i.e.*, transmission security limits) to more closely align the benefit estimation procedure with the optimization tool's use in NYISO's capacity market operations. In addition, the NYISO performed this assessment for both a reference case in which all existing capacity localities are retained and a sensitivity in which the G-J locality zone is eliminated and a new H-J zone is created. Finally, while the original analysis estimated and presented a range of benefits for a representative combination of Tier 1 and Tier 2 project combinations, this supplemental assessment constructed specific estimates for all Segment B projects in combination with the T027 Segment A proposal.

## 6.1. Optimization Procedure for Estimating ICAP Benefits

The NYISO's optimization tool was accepted by FERC in 2018 to replace the TAN45 methodology for establishing LCRs for each locality in the NYISO's capacity market. It minimizes ICAP costs by iteratively adjusting the megawatt requirements for each of the capacity zones, while observing emergency transfer criteria interface limits, transmission security limits for each locality and the LOLE reliability criterion of 0.1 days per year, and pricing capacity using a set of Net CONE cost curves. The NYISO has leveraged the tool here in order to estimate how future ICAP costs may be impacted by the proposed transmission projects.

Other than the inclusion of the transmission security limits in the optimization tool, the actual benefit calculations mirror that used in the original analyses, including the use of the same Net CONE curves. For each project combination and sensitivity studied, the NYISO ran the optimizer simulations for four sample years (i.e., 2025, 2030, 2035 and 2040) and calculated the annual capacity benefit as the pre-project costs less the post-project costs. A 20-year time-series of savings was then constructed using the simple average of the four savings values. Consistent with the Draft Report, the annual values were escalated by 1.92% to reflect growth in the Net CONE curves and then discounted by 6.988% to calculate a 20-year stream in 2018 dollars.

Consistent with the original analysis, the NYISO calculated the impact on ICAP costs using alternate assumptions on the clearing price. In one case, the clearing price is set at Net CONE beginning with the first year of the study period (2023) and extending through the end of the study period (2042). In the second case, clearing prices are assumed to more realistically gradually converge to Net CONE through the course of the study from current levels (approximately 33% of Net CONE in 2018).

The NYISO extended the prior capacity market analysis to study all Segment B projects in combination with the T027 Segment A project proposal. As a practical matter, all Segment B projects, other than T019, are electrically similar with regard to resource adequacy analysis. Therefore, the study work was limited to estimating the ICAP benefits for T027+T019 and T027+T029 which served as the proxy for all other Segment B projects.

### 6.2. Transmission Security Limits

Transmission Security Limits (TSLs) can be viewed as hard floors for each locality's LCR and are modelled as additional constraints in the optimization to ensure that all applicable reliability planning criteria are respected in setting the LCRs. The TSLs utilized in this estimation were calculated consistent with the LCR TSL process described in Section 1.2. The TSLs were used to establish the LCR floors for use in the optimization. For each locality and each year in the study case, the LCR floors (%) shown in Table A-8 were calculated as the locality megawatt limit as a percentage of the locality peak forecast load.

**Table A-8: Transmission Security LCR Floors**

| | | Transmission Security Floors | | | |
|---|---|---|---|---|---|
| | | J | K | GHIJ | HIJ |
| Base | 2025 | 80.79% | 103.65% | 86.88% | 68.95% |
| | 2030 | 81.00% | 103.86% | 87.37% | 70.02% |
| | 2035 | 81.88% | 104.08% | 88.07% | 71.25% |
| | 2040 | 82.72% | 104.28% | 88.74% | 72.42% |
| T019 | 2025 | 80.79% | 103.65% | 78.09% | 60.85% |
| | 2030 | 81.00% | 103.86% | 78.80% | 62.13% |
| | 2035 | 81.88% | 104.08% | 79.76% | 63.60% |
| | 2040 | 82.72% | 104.28% | 80.68% | 65.00% |
| T029 | 2025 | 80.79% | 103.65% | 78.61% | 59.84% |
| | 2030 | 81.00% | 103.86% | 79.30% | 61.15% |
| | 2035 | 81.88% | 104.08% | 80.24% | 62.64% |
| | 2040 | 82.72% | 104.28% | 81.15% | 64.07% |

## 6.3. Scenarios

In this extended analysis, the NYISO studied two scenarios: a baseline case, and a second case in which the capacity zones are reconstituted due to pending changes to the resource mix and the construction of the AC Transmission projects. The baseline case reflects the load, resource, and topology assumptions incorporated in the baseline case for the production cost analysis. This is consistent with the assumptions used in the original ICAP benefit analysis.

There are two modifications in the second scenario. First, in the pre-project cases an H-J locality is created as UPNY/ConEd (G-to-H) emerges as a binding interface following the retirement of the Indian Point Energy Center. Secondly, in the post-project cases, the G-J locality is eliminated as UPNY/SENY no longer binds after the AC Transmission projects are placed in service. Given that Net CONE curves are not currently available for an H-J locality, the NYISO utilized the Net CONE for the G-J locality and adjusted the curves to reflect capacity available in the H-J locality.

Table A-9 presents the ICAP benefits estimated for the two scenarios through the optimization methodology.

**Table A-9: ICAP Benefits from Optimization Method**

| Case | Convergence to Net CONE | | Net CONE | |
|---|---|---|---|---|
| (20-year savings, 2018 $M) | T027+T019 | T027+T029[a] | T027+T019 | T027+T029[a] |
| Existing Localities | $744 | $584 | $1,040 | $816 |
| AC Transmission Eliminates G-J | $1,385 | $1,327 | $1,936 | $1,856 |

[a] Representative of all non-T019 Segment B projects.

## 6.4. Market Monitoring Unit's Findings

The NYISO's Market Monitoring Unit (MMU) performed an independent assessment of the capacity benefits of the proposed AC Transmission projects. The MMU has provided a memorandum detailing its methodology and estimates (provided in Appendix A). In short, the MMU's methodology is distinct from the optimizer approach outlined above and is designed to capture two segments of capacity benefits for transmission projects: avoided investment costs and enhanced reliability benefits. The former is derived from the reduced compensatory megawatts required to maintain a reliable system (at 0.1 LOLE); and the latter is derived from the lower LOLE (less than 0.1) with the transmission project in place.

The MMU estimated 20-year capacity benefits, shown in Table A-10, for the T027+T019 and T027+T029 project combinations for both the baseline case and the CES+Retirement case as modeled in the NYISO's production cost analyses.[8] The MMU impacts are less than those developed utilizing the optimization tool and are particularly driven by the project's impacts on the UPNY/ConEd interface limits (rather than UPNY/SENY). The table below summarizes the MMU's results.

**Table A-10: ICAP Savings from MMU Method**

| Case (20-year savings, 2018 $M) | T027+T019 | T027+T029 |
|---|---|---|
| Baseline Case | $237 | $218 |
| CES+Retirement Case | $592 | $523 |

### 6.5. Summary Conclusions

The NYISO developed a range of estimates for each of the Segment B projects in combination with the T027 proposal. For T019, the estimated benefits for the 20-year study period range from $744M to $1,936M; for all other Segment B projects, the estimated benefits range from $584M to $1,856M. The MMU's assessment yielded savings in range of $237M to $592M for T019, and $218M to $523M for all other Segment B projects.

These estimates show that T019 provides additional ICAP savings of $160M to $224M over 20 years as compared to other proposed projects using the optimization methodology, while the MMU's assessment indicated additional ICAP savings associated with T019 ranging from $19M to $69M.

While it is difficult to predict the precise amount of these future benefits, under either the NYISO or the MMU methodology, the T019 project produces the highest level of expected ICAP cost savings among the proposed Segment B projects. The Board has concluded that ICAP savings should be considered in the project ranking.

[8] The MMU also estimated 45-year savings but for purposes of comparison, only the 20-year values are reported here.

# 7. Interconnection Studies

The Public Policy Transmission Planning Process considers the status and results of the interconnection studies in evaluating and selecting the more efficient or cost-effective project. All of the AC Transmission projects are currently under evaluation in the NYISO's Transmission Interconnection Procedures under Attachment P to the NYISO's tariff. The Board requested further investigation of two interconnection issues that were outstanding at the time the Draft Report was issued: potential subsynchronous resonance due to series compensation, and the feasibility of a Middletown transformer upgrade. This section describes updates to the two issues.

## 7.1. Potential Subsynchronous Resonance Issue

Subsynchronous resonance (SSR) is a phenomenon that occurs between a series-compensated transmission line and the shaft system of a thermal generator unit. The series-compensated line can cause the network's natural frequencies to fall into the sub-synchronous frequency range (0-60 Hz) which can interact with the resonant frequencies of the turbine shaft system and cause serious damage to the turbine shaft. A generator that is connected near a highly series-compensated transmission line can be at considerable risk for undamped subsynchronous oscillations. A generator does not have to be radially connected to a series-compensated transmission line before SSR occurs, though the risk for generators in an interconnected network is typically less than in a radial system. The SSR phenomenon can be studied by performing frequency scanning of the network to calculate the driving point impedance, as seen from the neutral of the generator, and comparing the resonant frequencies with those of the turbine shaft system.

The National Grid/Transco T019 Segment B proposal introduces a potential risk of SSR that may be caused by interactions between the proposed 50% series compensation and nearby synchronous generators. As part of the System Impact Study conducted for T019 (NYISO Interconnection Queue #543) under Attachment P of the NYISO Open Access Transmission Tariff, Burns & McDonnell conducted an SSR screening study to identify any potential SSR problems that the proposed series capacitors may cause to nearby generators. A review of subsynchronous control interaction was not performed as a part of the screening study. While an initial draft of the screening study submitted by National Grid/Transco indicated that the proposed series compensation would not present a material SSR risk, the final screening study for the System Impact Study indicated that SSR could potentially be an issue. The study identified the potential for SSR between the Empire combined cycle plant (also known as Besicorp) and the project's Knickerbocker-Pleasant Valley series compensation. The Facilities Study for the project will include further screening analysis with other nearby generators and detailed electromagnetic transient studies of any potential resonant conditions. If potential resonant conditions are found, additional network upgrade facilities will also be identified in the Facilities Study.

The NYISO engaged ABB to independently develop and estimate costs for conceptual mitigation solutions to resolve the potential SSR issues identified in the Burns & McDonnell SSR screening study for the National Grid/Transco T019 Segment B project. The ABB report, included as Appendix B, documents a review of various mitigation measures and provides high-level cost estimates.

The NYISO requested ABB to evaluate five mitigation options under two scenarios: (1) SSR occurs only at the Empire plant, and (2) SSR occurs at Empire, Athens, and Cricket Valley plants. ABB estimates that if SSR mitigation is required only at the Empire plant, ABB estimates that costs for mitigations would range from $565,000 to $1,300,000. If SSR mitigation is required at Empire, Athens, and Cricket Valley, ABB estimates that costs would range from $1,860,000 to $4,875,000. ABB provides the pros and cons of each of the five mitigation options. ABB does not recommend and did not provide cost estimates for the option involving resonant blocking filters given that this option is not standard within the industry.

ABB notes that the risk for SSR and the nature of any potential SSR issue is inconclusive based on the current information. ABB also advises that before any mitigation option can be selected, additional analysis is necessary to confirm whether or not there is a risk of SSR and, if so, the precise nature of the SSR issue. Specifically, ABB identifies some concerns with regard to the risk of torsional interaction. Torsional interaction occurs when the effects of an electrical resonance properly align in frequency with a mechanical torsional mode of a machine. ABB states that the risk for torsional interaction is not limited to a radial connection between the machine and the series capacitor, but can occur anytime that the electrical damping becomes negative so long as 1) the mechanical mode aligns with the negative electrical damping; and 2) the electrical damping is sufficiently negative to overcome the mechanical damping. It is assumed that any additional studies to identify the potential for SSR associated with T019, and any necessary mitigation measures, will be addressed through the NYISO interconnection processes.

The ABB Report indicates that any potential SSR issue resulting from the series compensation associated with T019 can be mitigated in a cost effective manner. The need for, and design of, the appropriate mitigation measures will be determined during the remaining portion of the interconnection process and design phase for T019. Therefore, the Board has concluded that T019's series compensation and the potential associated risk of SSR should not negatively affect the project's ranking.

### 7.2. Middletown Transformer

The NAT/NYPA T029 and T030 Segment B proposals include replacement of the existing Orange & Rockland Middletown 345/138 kV 562 MVA transformer with a larger 720 MVA transformer. As part of the System Impact Study conducted for T029 (NYISO Interconnection Queue #559) under Attachment P of the NYISO Open Access Transmission Tariff, Orange & Rockland conducted a physical feasibility analysis for the proposed Middletown transformer. O&R identified a potential need for additional Network Upgrade Facilities (NUFs) at the Middletown substation, the Middletown – Shoemaker 138 kV line, and Shoemaker 138 kV substation and raised concerns related to the space required for the proposed transformer, permitting, and outage coordination.

In response to O&R's concerns, SECO conducted a site visit with O&R at the Middletown substation on August 13, 2018 to perform an independent physical feasibility evaluation and environmental assessment of the proposed replacement of the Middletown transformer. SECO determined that the larger transformer would fit inside the Middletown substation, which is assessed to be capable of holding a transformer with a depth of up to 60 feet. Additional equipment at Middletown Substation will have to be replaced and/or relocated. SECO determined the installation of the proposed transformer is physically feasible without impacting the nearby wetlands.

The NUFs associated with the Middletown transformer replacement identified in the System Impact Study will be further evaluated in the Facilities Study and will be refined with respect to equipment, design detail and cost, as applicable.

As indicated in the transfer capability assessment, it was found that the UPNY/SENY N-1-1 Normal and Emergency Transmission Security Limits are not a distinguishing factor among the proposed Segment B projects. It was also found that the Middletown transformer would not provide significant incremental benefits under the studied outage conditions when considering the alternate generation dispatch methodology.

## 8. Summary of Board Revisions

Transfer Capability Assessment:

- The Board views that the additional transfer capability provided by T019 constitutes a material benefit as compared to the other proposed projects which will allow for opportunities to leverage additional benefits from future upgrades to New York's transmission infrastructure.
- The additional transfer capability of the T019 project will materially improve the bulk power system's resilience, alleviate constraints between upstate resources and downstate load centers, and allow for greater operational flexibility as compared to the other proposed Segment B projects. The Board has concluded that the additional transfer capability provided by T019 should be reflected as a grid resilience benefit in the Operability metric.
- The Board requested further evaluation of how the Segment B projects could accommodate additional generation deactivations within Lower Hudson Valley if they occur while maintaining reliability because of the associated increase in UPNY/SENY transfer capability. This analysis indicates a significant benefit from the T019 project in a future scenario where the New York system is impacted by large upstate renewable additions and potential generation retirements.
- The Board has concluded that the increased transfer capability associated with the T019 project should be reflected as a material benefit in the Operability and Performance metrics as the project provides additional flexibility in operating the system under design and extreme conditions, and provides better utilization of the UPNY/SENY interface. With the best Cost per MW, T019 achieves this transfer capability more cost effectively than the other Segment B projects.

Installed Capacity Cost Savings Benefits:

- The Board views relative installed capacity cost savings as an appropriate consideration when comparing overall project performance and relative project ranking. While it is difficult to predict the precise amount of these future benefits, NYISO staff, along with the MMU, have each calculated a reasonable order of magnitude estimate of ICAP savings at the Board's request.

- While the estimated calculated savings differ, what is common across the NYISO and MMU methodologies and scenarios is that T019 consistently produces the highest level of ICAP cost savings among the proposed projects. This is a significant finding, which the Board concludes should be considered in the project ranking.

Grid Resilience Benefits:

- The T019 project foundations and structures are designed to specifications that exceed minimum engineering standards. While the cost associated with the enhanced structures is higher, the design provides incremental resilience benefits that are not provided by other proposed projects.

- The Board views the potential benefits of storm hardened transmission facility designs and the ability to withstand heavier ice accumulation loadings and limit cascading structure failures as providing meaningful resilience benefits as compared to the alternate proposed projects. The Board concludes that the incremental resilience benefit of the T019 structural design should be reflected more prominently in the Operability metric and in the project ranking.

Structure Heights:

- Considering the language provided in the PSC Order establishing the AC Transmission need, as well as an understanding of the Article VII siting process, the Board concludes that the PSC, not the NYISO, would address the visual impacts resulting from the number and height of structures used by Developers and that the PSC will determine how to modify projects to address these issues in Article VII siting proceedings.
- Accordingly, the Board has concluded that structure height, as a risk to project siting, should not be used to differentiate between project rankings.

Series Compensation Issues and Related Operational Benefits:

- The Board is satisfied that any potential SSR or related issues resulting from the series compensation can be mitigated in a cost effective manner. The need for, and design of, the appropriate mitigation measures will be determined during the remaining portion of the interconnection process and design phase for T019. Therefore, the Board concluded that the series compensation and the potential associated risk of SSR should not negatively affect T019's ranking.

- Additionally, the Board asked NYISO staff whether there are potential operational benefits associated with the series compensation capability included with T019. NYISO staff provided the Board with information related to how the proposed series compensation can provide certain operational benefits from improved utilization of the UPNY/SENY interface through NYISO actions directing the operational status of the series compensation. The Board has concluded that T019's improved control of Segment B power flows should be reflected as a benefit in the Performance metric.

Production Cost Analysis / Carbon Pricing Sensitivity:

- The Board requested additional production cost analysis to study the potential impact of incorporating carbon pricing in the NYISO's wholesale market on the relative cost effectiveness of Segment B projects.
- The analysis found that while there were increases in the production cost savings for all Segment B projects, the inclusion of the social cost of carbon did not alter the comparative ranking of projects with regard to production cost savings to capital cost ratio.

Middletown Transformer:

- In response to concerns voiced by the facility owner, the NYISO conducted site visits and additional analysis to determine that there were no appreciable barriers to accommodating the upgrade to the Middletown substation proposed by NAT/NYPA.
- Using the alternate dispatch methodology for the transfer limit analysis documented in this Addendum, it is found that the benefits provided by the proposed transformer upgrade are minimal and not a significant distinguishing factor among the Segment B projects.

Project Synergy and Diversity Considerations:

- The Draft Report included a synergy cost savings that might be realized if a single to developer conducted the work to build both segments. The conservative 5% was provided by the NYISO independent consultant (SECO) to represent shared common services. The Board asked NYISO staff and SECO to also consider whether having a diversity in project developers (*i.e.*, different developer for Segments A and B) could have benefits outside costs. SECO opined that having different developers for each segment could bring qualitative benefits, such as diversity of financing risks of the projects and the availability of additional resources to support project development.

- Subsequently, the Board has concluded that while cost savings may be realized from synergies of a common developer to Segments A and B, there are also diversity benefits that may be realized.

## 9. Revised Ranking

Based on consideration of all the evaluation metrics for efficiency or cost effectiveness, and having given due weight to metrics according to input from the NYISO Board and subsequent conclusions reached by the Board, the NYISO has determined the following revised ranking of the Segment B projects.

**Table A-11: Segment B Overall Ranking**

| Ranking | Project ID | Developer Name | Project Name |
|---|---|---|---|
| 1 | T019 | National Grid / Transco | New York Energy Solution Seg. B |
| 2 | T029 | North America Transmission / NYPA | Segment B Base |
| 3 | T023 | NextEra Energy Transmission New York | Enterprise Line: Segment B-Alt |
| 4 | T022 | NextEra Energy Transmission New York | Enterprise Line: Segment B |
| 5 | T030 | North America Transmission / NYPA | Segment B Enhanced |
| 6 | T032 | ITC New York Development | 16NYPP1-1B AC Transmission |

In consideration of the conclusions described in Section 8, T019 is ranked first among the Segment B projects. Based on the estimated project schedules, the in-service date established for the purposes of the Development Agreements for the selected Segment A and Segment B projects is December 2023. Critical comparisons of the Segment B projects and the resulting ranking are summarized below:

- T019 has the highest incremental UPNY/SENY transfer capability, resulting in the lowest cost per MW ratio, highest production cost savings, highest $CO_2$ emissions savings, and highest ICAP savings of the Segment B projects. The series compensation component of the project provides performance benefits through greater operational flexibility and utilization of the UPNY/SENY interface. The project also has the most resilient foundation and structure design resulting in significant benefits for the operability of the transmission system during extreme weather events.

- T029 is estimated to have the second-lowest capital costs among the Segment B projects. However, the project achieves less production cost savings than T019 and has a higher Cost per MW ratio. T029 also has a less resilient foundation and structure design than T019.

- T023's capital costs are estimated to be slightly more than T029 with comparable electrical performance and comparable replacement of aging infrastructure, therefore T023 is ranked lower than T029. T023 would retire additional aging lattice transmission structures compared to T022 resulting in a more resilient design overall.

- T022 is estimated to have the lowest capital costs of the Segment B projects with comparable electrical performance as the other Segment B projects, with the exception of T019. However, T022 proposes the least amount of aging infrastructure replacement among Segment B projects.
- T030 is more expensive because of an additional conductor (triple-bundle rather than double-bundle), however the additional conductor actually results in less production cost savings in the CES+Retirement scenario. As such, T030 has the second lowest production cost benefit/cost ratio of the Segment B projects.
- T032 is the most expensive Segment B project with numerous inherent siting risks in the design, as identified in the Draft Report, with no material incremental performance benefits. T032 has the lowest production cost benefit/cost ratio and the highest cost-per-MW ratio.

## Additional Appendices

### Appendix G – Market Monitoring Unit Memo Re: Estimating Capacity Benefits

### Appendix H – ABB Subsynchronous Resonance Mitigation Cost Estimation Report