Assessment of the Buyer-Side Mitigation Exemption Tests for the Class Year 2017 Projects

POTOMAC ECONOMICS

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EXECUTIVE SUMMARY

The NYISO administers buyer-side market power mitigation ("BSM") measures in New York City ("Zone J") and the G-J Locality to prevent entities from artificially suppressing capacity prices below competitive levels by subsidizing uneconomic entry.[1] The BSM measures deter such anticompetitive entry by imposing an Offer Floor on resources that do not satisfy criteria that are described below. The Offer Floor acts as a deterrent because it would prevent such a resource from affecting capacity prices unless the prices rise to a level that would justify unsubsidized entry of the project.

The NYISO evaluates each Examined Facility in relation to the Class Year process to determine whether it should be subject to Offer Floor mitigation. The NYISO's Tariff requires the Market Monitoring Unit to prepare a report that must be posted concurrently with the results of any BSM determinations.[2] Starting in Class Year 2017 ("CY17"), the NYISO issues final determinations in two settlement phases if the Class Year "bifurcates":

- First, for Examined Facilities that do not require additional System Deliverability Upgrades ("SDU") studies and elect to settle early as part of the first phase of CY, and
- Second, for Examined Facilities that require additional SDU studies and elect to proceed with the studies, and for Examined Facilities that do not require additional SDU studied but elect to settle in the second phase.

CY17 bifurcated because two Examined Facilities elected to proceed with additional SDU studies. This report provides our review of the BSM evaluations for Examined Facilities that were evaluated in both phases of CY17.[3]

Examined Facilities in CY17 have been evaluated for a Competitive Entry Exemption ("CEE") and under the Part A & B tests. Generally, Examined Facilities can elect to request a CEE if they do not have contracts, agreements, arrangements, or relationships with certain entities that

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1 Terms with initial capitalization not defined in this report have the meaning set forth in the NYISO's Market Administration and Control Area Services Tariff ("MST" or "Tariff"), and if not defined therein, then in Open Access Transmission Tariff Attachment S.

2 See MST Sections 23.4.5.7.6.8, 30.4.6.2.12, and 30.10.4.

3 In July 2019, we published a report ("CY17-1 BSM Report") that discussed our review of the BSM evaluations for Examined Facilities that settled in the first phase of CY17 ("CY17-1"). We revised the CY17-1 BSM Report to include our review of the CY17-2 BSM evaluations.

could serve as a conduit for a subsidy.[4] All other Examined Facilities are evaluated under the Part A & B tests, which exempt a project if a) the projected revenues it would receive from the wholesale market would exceed the project costs, or b) if the project is needed to satisfy for a Locality's capacity requirement.

The following table provides a description of each CY17 Examined Facility and the status of its BSM evaluation.[5]

Examined Facility	Zone	Summer ICAP MW	Type	CY17 Phase	Determination
Cricket Valley Energy Center Project ("CVEC Project")	G	1020	CC	17-1	Exempt - CEE
Bayonne Energy Center II Project ("BEC II Project")	J	120	CT	17-1	Exempt - CEE
Berrians East Replacement Project ("CY17 Berrians Project")	J	508 (Net +4MW)	CT	17-1	Exempt - Part B
East River 6 Additional CRIS MW Project ("East River 6 Project")	J	8	Additional CRIS	17-1	Exempt - Part B
Champlain Hudson Interconnection Project ("CHPE Project")	J	1000	HVDC Line	17-2	No Final Determination - Dropped out
Linden Cogen Uprate Project ("Linden Uprate Project")	J	234	CT	17-2	No Final Determination - Rejected SDU cost allocation
Linden Additional CRIS MW Project	J	32	Additional CRIS	17-2	No Final Determination - Dropped out

The remainder of this Executive Summary provides an overview of the BSM evaluations for the CY17.

Evaluation of Examined Facilities for Competitive Entry Exemption in CY17

In CY17-1, the NYISO evaluated three Examined Facilities for a CEE – the CVEC Project, the BEC II Project, and the CY17 Berrians Project. The NYISO reviewed the project developers' certifications along with other documentation submitted in relation to the CEE requests. The NYISO evaluated the submissions for any non-qualifying contractual relationships, and

4 Currently, the NYISO tariff does not include provisions for a project that requests Additional CRIS MW for an existing unit that already has CRIS to receive a CEE. Such projects are evaluated under the Part A and B tests.

5 The proposed CY17 Berrians Project is a replacement project that would replace 504 MW of existing peaking capacity with 508 MW of new combustion turbine units.

concluded that the BEC II Project and the CVEC Project were eligible for the CEE. Accordingly, these Examined Facilities were determined to be exempt from an Offer Floor.[6]

The NYISO's review of the documents submitted by the developers of the CY17 Berrians Project indicated that the resource would not qualify for a CEE. Therefore, the NYISO evaluated the project under the Part A and Part B test provisions, and determined the project to be exempt from an Offer Floor under the Part B test.

Evaluation of Examined Facilities under Part A and Part B Tests in CY17

In CY17-1, the NYISO provided initial BSM determinations for the CY17 Berrians Project, the CHPE Project and the East River 6 Project based on Part A and Part B tests. However, the CHPE Project elected to proceed to CY17-2 settlement phase, and only the CY17 Berrians Project and the East River 6 Project received a final determination under these tests in CY17-1.

In CY17-2, the NYISO confidentially provided initial BSM determinations to the Linden Uprate Project, the Linden Additional CRIS MW Project, and the CHPE Project. However, none of the CY17-2 Projects received a final determination as all three projects rejected their respective Project Cost Allocation ("PCA") for SDUs and Deliverable MW.[7]

CY17-1 Part A Test Results

The purpose of the Part A test is to ensure that a resource will be determined to be exempt when its capacity will be needed to satisfy the capacity requirement for a particular Locality. An Examined Facility is determined to be exempt under the Part A test if the price forecast for the first year of its operation is higher than the "default net CONE."[8]

The NYISO's forecasted UCAP prices for Zone J and the G-J Locality were lower than the respective DNC values during the first year of the Mitigation Study Period (May 2020 to April

6 CEE exemption determinations are subject to an obligation to provide notification of changes that might affect eligibility and recertifications through the project's Entry date.

7 The Linden Additional CRIS MW and the CHPE Projects rejected their PCA for SDUs and SUFs and dropped out of the class year. The Linden Uprate Project rejected its PCA for SDUs and accepted its PCA for only SUFs.

8 The Part A test compares a forecast of capacity prices in the first year of an Examined Facility's operation to the default net CONE ("DNC"), which is 75 percent of the Mitigation Net CONE ("MNC"). MNC is the price corresponding to the net CONE ("Net CONE") of the hypothetical unit modeled in the currently effective Demand Curve reset. Net CONE refers to the annualized levelized cost of new entry after deducting the annual revenues earned in excess of operating costs from the sale of energy and ancillary services.

2021). Accordingly, none of the Examined Facilities that settled in CY17-1 were determined to be exempt under the Part A test.

The key driver of the Part A test results for the Zone J Examined Facilities was that the assumed amount of capacity from existing suppliers exceeded the forecasted ICAP requirements during 2020/21. Before including the capacity of the CY17 Projects, the NYISO forecasted that capacity sales during the Summer 2020 Capability Period would exceed the requirement for Zone J by approximately seven percent in CY17-1 BSM evaluations. However, the Zone J Examined Facilities would generally not be exempt under the Part A test unless the forecasted capacity margin was less than approximately six percent.[9] Hence, the NYISO forecasted that none of the Zone J Examined Facilities that settled in CY17-1 will be needed to satisfy the capacity requirements (plus the applicable margin). Overall, we find that the assumptions used in the Part A test were in accordance with the NYISO's Tariff.

CY17-1 Part B Test Results

In the CY17-1 BSM evaluations, the Unit Net CONE ("UNC") of the CY17 Berrians Project and the East River 6 Project were lower than the forecasted capacity prices over the three-year Mitigation Study Period, which is from May 2020 to April 2023. Accordingly, these two projects were determined to be exempt from the Offer Floor under the Part B test.[10]

The key driver of the Part B test results was the exclusion of capacity from the retiring Indian Point facility starting in the second year of the Mitigation Study Period, which is from May 2021 to April 2022.[11] The retirement of Indian Point significantly reduced the available capacity supply in G-J Locality, resulting in high capacity prices for the G-J Locality as well as Zone J (since Zone J is part of the G-J Locality). These factors combined with relatively low costs of projects that replace existing facilities and Additional CRIS MW Projects such as the CY17 Berrians Project and the East River 6 Projects led them to be exempt from the Offer Floor in the CY17-1 BSM evaluations. Overall, we find that the CY17-1 Part B tests were performed in accordance with the NYISO MST, and the results are consistent with the fundamental objective of the BSM measures.

9 The Part A test is actually based on a comparison of conditions in the Summer and Winter Capability Periods. Details are provided in Section III.

10 The NYISO confidentially provided an initial determination to the CHPE Project as part of CY17-1. The project elected to proceed to CY17-2 and did not receive a final determination in CY17-1.

11 Indian Point Unit 2 is scheduled to shut down by April 30, 2020 and Unit 3 by April 30, 2021.

Enhancements to the BSM Procedure

The NYISO made several modifications to its test methodology in the CY17 BSM evaluation. The application of new MST inclusion and exclusion rules for determining the in-service capacity corrected a major deficiency of the test procedure. In addition, the NYISO forecasted the LCRs during the MSP using the Alternative LCR methodology and accounting for changes in the resource mix (e.g., Indian Point retirement) and interface transfer limits. Both of these changes had a considerable impact on the price forecasts and significantly enhance the test procedure.

As a part of our review, we have identified several issues that, if addressed, would improve the accuracy of the BSM evaluations.[12] These mainly relate to the test assumptions regarding forecasted in-service capacity supply, entry dates of the Examined Facilities, and estimation of interconnection costs. In addition, we also recommend modifying the Part A test procedure to exempt Examined Facilities that can satisfy a capacity shortfall in all Localities where the facility is located. A number of the proposed improvements require changes to the NYISO's Tariff. We find that addressing these issues would not have altered the ultimate CY17 BSM determinations, although these issues may have significant impacts on the results of future BSM evaluations.[13] Accordingly, we recommend the NYISO continue to work with its stakeholders to develop reasonable rules for future evaluations.

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12 See Section VIII. The NYISO has initiated stakeholder processes to address some of the issues discussed herein.

13 Assuming a more reasonable start date could have exempted an Examined Facility under the Part A test. However, the facility also received a Part B exemption, and the ultimate BSM determination was unaffected.

I. Introduction and Summary

The NYISO's Market Administration and Control Area Services Tariff ("MST" or "Tariff") requires that the Market Monitoring Unit ("MMU") prepare a report to be posted concurrently with the results of buyer-side market power mitigation ("BSM") determinations.[14] For each Class Year ("CY"), the NYISO would issue final determinations in up to two settlement phases, depending on whether additional SDU studies are required for a subset of the Examined Facilities and if such facilities choose to proceed with the additional studies.[15, 16]

The NYISO provided initial BSM determinations in the first settlement phase of the bifurcated Class Year 2017-1 ("CY17-1") for five Examined Facilities. In CY17-1 BSM evaluations, four Examined Facilities received final determinations that exempted them from an Offer Floor pursuant to the provisions of either the Part A and Part B tests or the Competitive Entry Exemption ("CEE").[17] One of the Examined Facilities elected to proceed to the second settlement phase of CY17 ("CY17-2") and did not receive a final determination in CY17-1.

In CY17-2 settlement phase, the NYISO confidentially provided initial BSM determinations to three Examined Facilities. Two of the three CY17-2 Projects rejected their Project Cost Allocation and dropped out of CY17, while the third project rejected its PCA for SDUs and Deliverable MW and accepted only its PCA for SUFs. Accordingly, none of the CY17-2 Examined Facilities received a final determination.

This report provides our review of the NYISO's CY17 BSM evaluations.[18] We find that the NYISO's BSM determinations for CY17 were made in accordance with the Tariff and based on reasonable assumptions.

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14 See Astoria Generating Company, L.P., et al. v. New York Independent System Operator, Inc., 139 FERC ¶ 61,244 (2012) at PP 130. Also see MST §23.4.5.7.6.8.

15 See MST §23.4.5.7.3.3.5.

16 Terms not defined herein have the meaning set forth in the MST, and if not defined there, then as defined in the Open Access Transmission Tariff ("OATT").

17 The Part A and Part B tests are set forth in MST §23.4.5.7.2. The CEE provisions are set forth in MST §23.4.5.7.9. Details on the NYISO's general application of these tests are provided in the *BUYER SIDE MITIGATION NARRATIVE AND NUMERICAL EXAMPLE* ("BSM Numerical Example"), dated May 17, 2018. Details on the capacity price forecast assumptions used for CY17-1 Examined Projects are provided in *BUYER SIDE MITIGATION ICAP FORECAST – ASSUMPTIONS AND REFERENCES FOR CLASS YEAR 2017-1 EXAMINED PROJECTS* ("BSM CY17-1 Forecast Assumptions"), dated June 8, 2018. Both documents are available at: https://www.nyiso.com/market-monitoring.

18 The NYISO's final determinations in Class Year 2017-1 are available at: https://www.nyiso.com/market-monitoring.

Section I.A presents a brief overview of the CY17 Examined Facilities and the NYISO's BSM determination for each Examined Facility.

A. CY17 Examined Facilities

1. Examined Facilities that Elected to Settle in CY17-1

Five of the CY17 Projects did not require additional SDU studies and were provided initial determinations prior to the commencement of the Bifurcated Decision Period.[19] The four Examined Facilities that elected to settle and received final determinations in CY17-1 include:

- *Cricket Valley Energy Center Project ("CVEC Project")* - The CVEC Project is a proposed natural gas-fired combined-cycle plant with three units, each having a 1 x 1 x 1 configuration with total nominal capacity of 1020 MW. The CVEC project is located in Zone G and was determined to be exempt from an Offer Floor pursuant to the CEE provisions.
- *Bayonne Energy Center II Project ("BEC II Project")* – The BEC II Project is a 2x0 combustion turbine unit with nominal capacity of 120 MW. The project is located in Zone J and was determined to be exempt from an Offer Floor pursuant to the CEE provisions.
- *Berrians East Replacement ("CY17 Berrians Project")* - The CY17 Berrians Project consists of 3 combustion turbine units with a total nominal capacity of 508 MW. The CY17 Berrians Project is located in Zone J and requested a CEE, but was deemed to not qualify for it. The NYISO evaluated the CY17 Berrians Project under the Part B test and determined the project to be exempt from Offer Floor.
- *East River 6 Additional CRIS MW Project ("East River 6 Project")* – The East River 6 Project entails a capacity uprate of 8 MW at the existing East River Unit 6 in Zone J. This Additional CRIS MW Project was determined to be exempt under the Part B test.[20]

2. Examined Facilities that Elected to Settle in CY17-2

The three Examined Facilities that elected to settle and received initial determinations in CY17-2 include:

- *Champlain Hudson Interconnection Project ("CHPE Project")* - The CHPE Project is a proposed 1000 MW High Voltage Direct Current ("HVDC") merchant transmission line running from the US-Canada border to New York City. The NYISO confidentially provided the CHPE Project an initial determination as part of the CY17-1 BSM evaluations. The project subsequently elected to proceed as a member of CY17-2 with no changes to its ERIS or CRIS. The project confidentially received an initial

19 The CHPE Project opted to proceed as a member of CY17-2, and did not receive a final determination in CY17-1.

20 See MST §23.2.1 for the definition of Additional CRIS MW and MST §23.4.5.7.6 for the provisions related to BSM evaluation of Additional CRIS MW projects.

determination in CY17-2. However, the project developer rejected its PCA and dropped out of CY17. Hence, it did not receive a final determination.

- *Linden Cogeneration Uprate Project ("Linden Uprate Project")* – The Linden Uprate Project involves addition of a 234 MW unit at the existing Linden cogeneration facility in Zone J. The project confidentially received an initial determination in CY17-2. However, the project developer rejected its PCA for SDUs and Deliverable MW, and only accepted its PCA for SUFs. Hence, it did not receive a final determination.
- *Linden Additional CRIS MW Project* – The Linden Additional CRIS MW Project entails a capacity uprate of 32 MW at the existing units that are a part of the Linden cogeneration facility in Zone J. The project confidentially received an initial determination in CY17-2. However, the project developer rejected its PCA and dropped out of CY17. Hence, it did not receive a final determination.

B. Summary of BSM Report for CY 17 Examined Facilities

Overall, we found that the results of the NYISO's BSM determinations were consistent with the requirements of the Tariff. This report discusses key results and assumptions in the BSM exemption tests in both settlement phases of CY17. For each assumption, the report discusses how the outcome of the test was affected by the assumption, whether the assumption was in accordance with the MST, and whether the assumption was generally reasonable and consistent with the purposes of the BSM measures. In discussing the reasonableness of the particular assumptions, we identify potential concerns that may justify changes in NYISO procedures and in the BSM rules. A list of assumptions that may be improved for future BSM exemption tests is provided in Section VIII of this report. The following sections review key elements of the NYISO's BSM determinations:

- Section II discusses the NYISO's review of the CY17 Berrians, BEC II, and CVEC Projects for the Competitive Entry Exemption.
- Section III discusses the Part A test in which the NYISO compares the forecasted ICAP price in the first year of the Mitigation Study Period ("MSP") to the Default Net CONE.
- Section IV discusses the results of the Part B test in which the NYISO compares the forecasted ICAP price during the three-year MSP to the project's Unit Net CONE. Key inputs to the Part B test are discussed in Sections V and VI.
- Section V evaluates the NYISO's estimates of the cost of new entry ("CONE") for each Examined Facility, which is used to calculate its Unit Net CONE.
- Section VI evaluates the estimated net revenues for each project from the NYISO's Energy and Ancillary Services markets. The estimated net revenues are also used to calculate the project's Unit Net CONE.
- Section VII discusses assumptions that affect both the Part A and Part B tests.
- Section VIII summarizes our overall conclusions and discusses issues that could be addressed in future BSM determinations.

II. Evaluation of Examined Facilities for Competitive Entry Exemption

The Tariff provides for the NYISO to exempt from an Offer Floor Examined Facilities that have requested a Competitive Entry Exemption and that meet certain criteria under the Competitive Entry Exemption ("CEE") provisions.[21] Generally, the CEE provisions were put in place to exempt merchant projects that do not receive payments from New York State governmental entities or a Transmission Owner from buyer-side mitigation because the developers of such projects should have market incentives to enter based on their own expectations of market conditions. MST §23.4.5.7.9 specifies the requirements that a project developer needs to fulfill in order to establish that the project is not supported by payments or other subsidies (either direct or indirect) through contracts with non-qualifying entities.

A. CY17 Evaluation of CEE Projects

In CY17, three Examined Facilities requested a CEE.[22] The project developers executed initial Certification and Acknowledgement forms and again as they recertified at different points during the evaluation. The developers also submitted a schedule listing planned or existing contracts with non-qualifying entities and a number of such documents, along with information necessary to calculate a Unit Net CONE ("UNC") for the project. The CEE Project developers' submission to the NYISO included non-disclosure agreements, interconnection studies, environmental compatibility studies, and feasibility reports for the Examined Facilities as well as documents of projects owned by the developer and its affiliates.

The NYISO reviewed the developer submissions and, where applicable, requested additional information to determine whether the developers have entered or plan to enter into non-qualifying contracts. The NYISO determined the BEC II Project and the CVEC Project to be exempt from an Offer Floor under the CEE provisions. However, the NYISO's review indicated that the CY17 Berrians Project did not meet the required criteria for granting a CEE. The NYISO subsequently evaluated the CY17 Berrians Project under the Part B test and determined the project to be exempt from an Offer Floor. We find the determinations for the CY17 CEE Projects were made in accordance with the MST.

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21 MST Section 23.4.5.7.9.

22 See NYISO notice available at: https://www.nyiso.com/documents/20142/3025517/Class_Year_2017_CEE_Notice.pdf/.

III. PART A TEST RESULTS

The Part A test compares a forecast of capacity prices for the first year of the MSP to the Default Net CONE, which is 75 percent of Mitigation Net CONE.[23] The purpose of the Part A test is to ensure that a resource is not mitigated when its capacity will be needed to satisfy the capacity requirement for a particular Locality.

CY 17-1 Part A Evaluation - In its CY17-1 BSM evaluation, the NYISO conducted the Part A test for five Examined Facilities. The NYISO tested these projects sequentially according to their presumptive Offer Floors from lowest to highest. A unit is exempt in the Part A test if the price forecast for the first year of the MSP is higher than the Default Net CONE. If a project receives an exemption, it is included in the test for the subsequent project. If a project does not receive an exemption, then it is excluded from the ICAP forecast for the subsequent project in the sequence.

Although the NYISO evaluated the CHPE Project and confidentially provided it an initial determination as part of CY17-1, the project opted to proceed as a member of CY17-2. Hence, it did not receive a final determination in CY17-1. In the CY17-1 BSM evaluation, the forecasted UCAP prices for the first year of the MSP were lower than the Default Net CONE of $143 per kW-year UCAP for Zone J and $117 per kW-year UCAP for G-J Locality. Consequently, none of the Examined Facilities that settled in CY17-1 were exempt under the Part A test.[24]

CY 17-2 Part A Evaluation - The NYSO evaluated the Linden Uprate Project, the Linden Additional CRIS MW Project, and the CHPE Project in CY17-2, and confidentially provided the project developers an initial determination. However, none of the CY17-2 Projects received a final determination as all three projects rejected their respective PCA for SDUs and Deliverable MW.

We find that the Part A tests in the CY17 BSM evaluations were performed using reasonable assumptions that were in accordance with the NYISO MST. Subsection A evaluates the assumptions used to forecast capacity prices and to compare the capacity prices with the Default Net CONE. The conclusion of this section describes how these factors in combination likely affected the overall results of the tests.

23 See *BSM Narrative and Numerical Example*, Section 2.

24 The NYISO was required to conduct a Part A and Part B for all CY17-1 Projects, even the ones that received a CEE. However, because the CVEC Project qualified for a CEE we only discuss the Part A test for CY17-1 Examined Facilities located in Zone J.

A. Implications of Factors Identified in Section VII

This sub-section discusses how key factors identified in Section VII affected the Part A test.

1. Starting Capability Period of Summer 2020

In accordance with the Tariff, the CY17 Projects were assumed to enter in Summer 2020.[25] However, it is unrealistic to assume that the Additional CRIS MW projects in CY17, which have very short lead times, or a nearly-operational combustion turbine such as the BEC II Project would begin operations at the same time as the CHPE Project, which would require a much longer development period.

For instance, in CY17-1 BSM evaluations, the forecasted ICAP prices for some of the Examined Facilities during the last two years of the MSP were substantially higher than the first year forecast due to the small capacity surplus in the G-J Locality.[26] Consequently, Zone J and G-J Locality prices were higher than the respective Default Offer Floors ("DOF") during 2021/22 and 2022/23. Hence, one of the Examined Facilities whose actual Commercial Operational Date ("COD") is likely to be after Winter 2020/21 could have received an exemption under the Part A test, if a more realistic Starting Capability Period were assumed. However, using a more realistic Starting Capability Period would not have altered the final outcome of the CY17-1 BSM evaluations, since the Examined Facility whose Part A test was impacted was determined to be exempt under other provisions of the Tariff.

2. Capacity Assumed to be In-service During the Mitigation Study Period

As discussed in VII.D, the NYISO made several assumptions regarding the set of resources that will be in-service before and during the MSP for the CY17 BSM evaluations. In particular, the following assumptions had a significant impact on the forecasted ICAP prices in the Part A test:

- Over 160 MW (ICAP Summer in CY17-1) and over 280 MW (ICAP Summer in CY17-2) from Zone J units that are currently in a Mothball Outage or an ICAP Ineligible Forced Outage ("IIFO") would not offer capacity in 2020/21 if they had a negative net present value from returning to service;
- Approximately 1000 MW of capacity (ICAP Summer) from Indian Point unit 2 in G-J Locality would be retired by 2020/21. The NYISO excluded this capacity based on publicly available information that the unit would cease operations.

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25 The assumption regarding the Starting Capability Period is discussed in further detail in subsection VIII.A.

26 See *Buyer Side Mitigation ICAP Forecast - Class Year 2017-1 Assumptions and References*, dated June 8, 2018, available at: https://www.nyiso.com/market-monitoring.

In the CY17-1 BSM evaluation, including all the capacity from the above two categories could have depressed the 2020/21 capacity price forecast for Zone J and the G-J Locality by up to $35/kW-year UCAP and $125/kW-year UCAP, respectively.[27] Therefore, this assumption did not impact the Part A test results, as including these two types of resources would have only further reduced the likelihood of exempting units under the Part A test.

3. Estimating Locational Capacity Requirements for the Mitigation Study Period

The Zone J Locational Minimum Installed Capacity Requirement ("LCR") for the 2018/19 Capability Year was 80.5 percent and 82.8 percent for the 2019/20 Capability Year .[28] In its CY17 BSM evaluations, the NYISO adjusted the Zone J LCR in 2020/21 to 83 percent to account for a number of factors including the retirement of the Indian Point 2 unit in April 2020.[29]

Although this adjustment had a significant impact on the Part A ICAP price forecast in the CY17-1 BSM evaluation, lowering the NYISO's LCR adjustment to the 2018/19 LCR of 80.5 percent would only have lowered the Zone J ICAP price forecast. Since none of the Zone J Examined Facilities received an exemption under the Part A test in CY17-1, this assumption by itself would not have changed the outcome of Part A test.

B. Potential Issue with the Part A Test Procedure

The Part A test is intended to exempt Examined Facilities whose capacity is needed to meet the requirement of a Mitigated Capacity Zone. In Part A test, the NYISO compares the forecasted ICAP prices for the first year of the MSP to the DNC for the Locality in which the Examined Facility is located.

Consider a BSM evaluation in which the only Examined Facility is a unit located in Zone J. The current test procedure would only compare the Zone J DNC with the Zone J ICAP price forecast during the first year of the MSP. Therefore, the current test procedure does not directly consider the level of a capacity supply in the G-J Locality. Consequently, if the Zone J price forecast is not affected by the G-J forecast, the current procedure could result in mitigating an Examined Facility even if it is required for meeting the G-J capacity requirement.

27 However, this increase would be offset partly by changes to LCR, higher forecasted sales from UDR projects and resources subject to an Offer Floor.

28 See Section 2.2 of the *Buyer Side Mitigation ICAP Forecast – Class Year 17-1 ICAP Forecast Assumptions & References and Buyer Side Mitigation ICAP Forecast – Class Year 17-2 ICAP Forecast Assumptions & References*.

29 See VII.F for a discussion of the NYISO's assumptions for LCRs during the MSP.

Although this issue did not impact the CY17 BSM evaluations, it could impact future BSM METs particularly if the capacity margin in the G-J Locality continues to be tight due to the retirement of Indian Point. Hence, we recommend the NYISO consider modifying its Part A test procedure to allow for exempting Examined Facilities if they are needed to satisfy the capacity requirement in any of the Localities where they are located.

C. Conclusions

The forecasted capacity prices in the Part A test of CY 17-1 were lower than the DNC in Zone J. Hence, none of the Zone J Examined Facilities received a Part A exemption in CY17-1. The NYISO performed the Part A test for three Examined Facilities in the CY17-2 settlement phase, and confidentially provided each developer its initial BSM determination. However, none of the CY17-2 Projects received a final determination as all three projects rejected their respective PCA for SDUs and Deliverable MW. Overall, we find that the Part A tests in CY17 evaluations were performed in accordance with the NYISO MST.

In the CY17-1 BSM evaluations, the NYISO's assumptions regarding LCRs, deactivating capacity and Starting Capability Period had a significant impact on the 2020/21 ICAP price forecast in the Part A test. If the assumptions regarding the Starting Capability Period were modified to be more realistic, one of the CY17-1 Projects may have received a Part A exemption. Ultimately, although this factor would not have altered the final determinations in the CY17, we recommend the NYISO modify its Tariff to allow more reasonable assumptions regarding Starting Capability Period.

IV. Part B Test Results

An exemption is granted in the Part B test if the average capacity price forecast over the three-year MSP is higher than the Unit Net CONE of the Examined Facility.[30] The Unit Net CONE is equal to the annualized levelized CONE of the project minus the net revenue earned from selling Energy and Ancillary Services.[31] The purpose of the Part B test is to ensure that a project is not mitigated when it would be economic for the project to move forward.

CY 17-1 Part B Evaluation - In the CY17-1 BSM evaluation, the NYISO conducted the Part B test for five Examined Facilities. The NYISO's ordering included the two CEE Projects and the Examined Facilities that are in CY17-2. All were ordered according to their presumptive Offer Floors from lowest to highest and tested sequentially. If the presumptive Offer Floor of an Examined Facility was lower than the ICAP price forecast, it was included in the test for the subsequent project. Otherwise, the Examined Facility was excluded from the ICAP forecast for the subsequent project in the sequence.

Although the NYISO evaluated the CHPE Project and confidentially provided it an initial determination as part of CY17-1, the project opted to proceed as a member of CY17-2. Hence, it did not receive a final determination in CY17-1. In CY17-1, the UNCs of the CY17 Berrians and the East River 6 Projects were lower than the corresponding capacity price forecast. Therefore, two projects received an exemption under the Part B test in CY17-1.

CY 17-2 Part B Evaluation - In the CY17-2 BSM evaluation, the NYISO conducted the Part B test for three Examined Facilities and confidentially provided an initial determination to each developer. However, none of the CY17-2 Projects received a final determination as all three projects rejected their respective PCA for SDUs and Deliverable MW.

Sub-section V.A evaluates the assumptions used to forecast capacity prices and to perform the BSM evaluation for each Examined Facility.

A. Implications of Factors Identified in Sections V, VI, and VII

This sub-section discusses how several key factors identified in other sections of this report affected the outcome of the Part B test in the CY17 BSM evaluations. Sections V, VI, and VII discuss in detail other assumptions that were used in the Part B test.

30 See BSM Numerical Example, Section 3.

31 The assumptions for the estimated annual levelized CONE calculations for the Examined Facilities are evaluated in Section V, while the reasonably anticipated net revenue assumptions are evaluated in Section VI. Other relevant forecasting assumptions are discussed in Section VII.

1. Starting Capability Period of Summer 2020

In accordance with the Tariff, the CY17 Projects were assumed to enter in Summer 2020.[32] However, it is unrealistic to assume that the Additional CRIS MW projects in CY17, which have very short lead times would begin operations at the same time as the CHPE Project, which would require a much longer development period.

In CY17-1 BSM evaluation, the forecasted ICAP prices during the last two years of the MSP were substantially higher than the first year forecast due to the low capacity margin in the G-J Locality.[33] Hence, assuming a project to be in service earlier than its actual start date could have led to mitigation of an otherwise economic project. On the other hand, assuming a nearly-operational project to enter into service later than its likely operational date could lead an uneconomic project to be determined exempt. Nonetheless, the Starting Capability Period assumption did not impact the outcome of the CY 17-1 BSM evaluation results.

In CY17-2 BSM evaluation, the average net EAS revenue for the CHPE Project in the first and second year of the MSP was 6 percent higher than its revenue third year of the MSP. As discussed in VI.E.1, this is because of the tighter capacity and energy margins in HQ in the later years. Hence, assuming a start date of 2023/24 (in line with the lead time of four years for most major transmission projects) for the CHPE Project, all else being equal, would have increased the UNC for the project. However, the Starting Capability Period assumption did not impact the outcome of the CY 17-2 BSM evaluation results.

2. Capacity Assumed to Be In-service during the Mitigation Study Period

As discussed in VII. D, the NYISO made several assumptions regarding the set of resources that will be in-service before and during the MSP for the CY17 BSM evaluations. In particular, the following assumptions had a significant impact on the forecasted ICAP prices in the CY17 Part B test:

- Over 160 MW (ICAP Summer in CY17-1) and over 280 MW (ICAP Summer in CY17-2) from Zone J units that are currently in a Mothball Outage or an ICAP Ineligible Forced Outage ("IIFO") would not offer capacity during the MSP if they had a negative net present value from returning to service;

32 The assumption regarding the Starting Capability Period is discussed in further detail in subsection VIII.A.

33 See *Buyer Side Mitigation ICAP Forecast - Class Year 2017-1 Assumptions and References*, dated June 8, 2018, available at: https://www.nyiso.com/market-monitoring.

- Over 1000 MW of capacity (ICAP Summer) from each Indian Point unit would be retired by the end of 2020/21 and 2021/22.[34] The NYISO excluded this capacity based on publicly available information that the units would cease operations.

In the CY17-1 BSM evaluation, assuming all of this capacity to be in service during the MSP would have significantly increased the capacity margin in the G-J Locality, and substantially lowered the Zone J ICAP price forecast for the Part B test. Including these units in the capacity supply and reversing the associated LCR adjustment would have resulted in a different Part B determination for a subset of the Examined Facilities that settled in CY17-1. We support the NYISO's assumptions that exclude these units from the capacity supply during the MSP.

3. Estimating Locational Capacity Requirements for the Mitigation Study Period

The 2019/20 Capability Year LCRs for Zone J and G-J Locality are 82.8 percent and 92.3 percent respectively. However, to account for the changes to the system prior to and during the MSP the NYISO adjusted the LCRs for its CY17 BSM evaluations.[35]

In the CY17-1 BSM evaluation, the Zone J price during the last two years of the MSP was determined by the G-J Locality's Demand Curve. This was due to the low G-J Locality capacity margin resulting from the retirement of Indian Point units. Consequently, the assumed LCR for the G-J Locality had a much larger impact on the Part B price forecasts (compared to the Zone J LCR assumption).

- The assumed G-J Locality's LCR was only marginally above the transmission security limits ("TSL"). Hence, decreasing the G-J Locality's LCR to its lower bound (i.e., the TSL level) would not change the outcome of the Part B test for the Examined Facilities that settled in CY17-1.[36]
- As discussed in Section VII.F, incorporating the impact of the CVEC Project on the transfer limits may have reduced the TSL for the G-J Locality by less than 2 percentage points over the MSP. However, adjusting down the G-J LCR to the reduced TSL value would not have impacted the outcome of the Part B test in the CY17-1 BSM evaluation.
- The NYISO utilized a higher value for Zone J LCR and a lower value for the G-J Locality LCR in its AC Transmission Study. The NYISO discussed the reasons for variation in LCRs across the AC Transmission Study and CY17 BSM evaluations in a

34 The assumption to remove the Indian Point capacity from the forecasted supply also resulted in changes to the forecasted LCR values.

35 See subsection VII.F.

36 The NYISO assumed a TSL of 90.5 to 91.5 percent for the G-J Locality during the MSP.

recently posted document.[37] Given the assumptions of an optimized IRM and higher G-J Locality TSL in the AC Transmission Study, it would not be appropriate to utilize the LCRs from that study in the CY17 BSM evaluation. Nonetheless, using the LCRs from AC Transmission Study would not have changed the outcome of the CY17-1 BSM evaluation.

In the CY17-2 BSM evaluation, the inclusion of capacity from exempt CY17-1 Projects resulted in a larger capacity margin in Zone J and the G-J Locality (relative to CY17-1). As a result, the capacity prices forecasted for Zone J during the MSP were determined by the Zone J demand curve. Since all three CY17-2 Projects are located in Zone J, the assumed LCR for the G-J Locality did not impact the Part B evaluation in CY17-2.

- The outcome of the Part B evaluations would not have changed even if the Zone J LCRs were adjusted to the values utilized in the AC Transmission Study or the CY17-1 BSM evaluations.

4. Forecasting ICAP Reference Point

In its previous BSM evaluations, the NYISO forecasted the ICAP reference points during the MSP by escalating the prevailing reference points at the time of analysis. For the CY17 BSM evaluations, the NYISO in compliance with changes to its Tariff forecasted the ICAP reference points for the MSP by adjusting the capital costs and net revenues of the peaking technology, the Winter-to-Summer ratio and the marginal tax assumptions.[38] As a result, the average forecasted Zone J ICAP reference point (over the MSP) under the new method was $10 per kW-year higher in CY 17-1 BSM evaluation and $15 per kW-year higher in CY 17-2 BSM evaluation than the forecasted value under the previous approach.

While this change had a significant impact on the ICAP price forecast, the final outcomes of the CY17 Part B tests were not impacted.

5. Implications of 2017 Tax Cuts and Jobs Act

The provisions of the recently enacted tax law (the 2017 Tax Cuts and Jobs Act or “TCJA”) impacted both the UNC of the CY17 Projects and the ICAP price forecast (by affecting the ICAP reference point). The changes to tax rate and deductibility of state and local taxes lowered the Zone J ICAP reference points by approximately $9 per kW-year during the Capability Years 2021/22 and 2022/23. The UNC values of the CY17 Projects were also reduced by up to seven percent due to changes in the marginal tax rate and state/ local tax deductibility. In addition, the UNC(s) for a subset of the eligible CY17 Projects were also affected by the project’s ability to

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[37] See *Differences in LCRs: CY2017-2 BSM & Public Policy AC Transmission Study*, dated May 30, 2019, available at: https://www.nyiso.com/documents/20142/3025517/Supplemental-LCR-information.pdf/e25b5075-ccd1-ccaa-9006-023a94709df5.

[38] See VII.B, VII.C, and BSM CY17-1 Forecast Assumptions.

fully depreciate its capital expenditures in the first year of its operation. This reduced the UNC of eligible CY17 Project(s) by over 17 percent.

Overall, incorporating the effects of TCJA made it more likely for the Examined Facilities to be exempt under the Part B test, but reversing the impact of the TCJA by itself would not have impacted the final results of the CY17 Part B tests.

6. Treatment of Pre-existing and/ or Common Facilities

Consistent with previous BSM evaluations, for Examined Facilities located at sites with pre-existing common facilities, the NYISO allocated the additional costs of developing the project to the CONE of the Examined Facility. In addition, to the extent that the CY17 Projects utilized pre-existing non-common facilities, the embedded costs (based on the book values) of such facilities were added to the CONE of the Examined Facility. This approach resulted in significantly lower capital and fixed costs of CY17 Projects relative to a new generation project, and hence, increased the likelihood of these projects receiving a Part B exemption.

7. CONE of Additional CRIS MW Projects

The existing capacity at the facilities requesting Additional CRIS MW in CY17 is exempt from Offer Floor because all of the facilities were in-service when the BSM measures were originally implemented in their respective locality.[39] Therefore, in accordance with MST §23.4.5.7.6.1, the NYISO based its UNC estimates on the incremental costs and revenues associated with the Additional CRIS MW.[40]

As a general matter, Additional CRIS MW projects involve uprates to existing facilities and do not incur many of the costs of developing a new generator. Consequently, the CONE for such projects is often well below the CONE of a new facility, increasing the likelihood of these projects receiving a Part B exemption.

8. Use of Gas Futures in LBMP Estimation

As discussed in VI.C.1, the NYISO's forecasts for LBMPs and net revenues were based on natural gas futures prices, which, on average, decreased from 2018/19 and 2019/20 to the MSP years in CY17-1 BSM evaluation and increased from 2018/19 and 2019/20 to the MSP years in

39 See Section 23.4.5.7.6 of the Services Tariff.

40 Although the Linden Additional CRIS MW Project was not issued a determination in CY17-1, its UNC was required for ordering and testing Examined Facilities sequentially in CY17-1 Part A and Part B tests. See subsection VII.H for the NYISO's procedure for testing multiple Examined Facilities.

CY17-2 BSM evaluation.[41] Consequently, all else being equal, the annual net revenue forecasts for all gas-fired units would follow a similar trend over these years. The energy and ancillary services ("EAS") offset used in the ICAP reference point is based on a prior three-year average of the net revenues that the Demand Curve unit would have received. Therefore, the usage of downward trending gas futures prices in CY17-1 BSM evaluations increased the EAS offset used in forecasting the ICAP reference point to a greater extent relative to the net revenues of gas-fired Examined Facilities in CY17-1 BSM evaluation. Similarly, in CY17-2 BSM evaluation, due to upward trending gas futures prices, the net revenues for gas-fired Examined Facilities increased to a greater extent relative to the EAS offset used in forecasting the ICAP reference point.

B. Conclusions

In the CY17-1 BSM evaluations, the UNCs of the CY17 Berrians Project and the East River 6 Project were lower than the average capacity price forecast over the three-year MSP. Accordingly, these two facilities were determined to be exempt from the Offer Floor under the Part B test.

The NYISO's ICAP price forecast excluded the capacity from the retiring Indian Point facility. The NYISO also modeled the impact of Indian Point retirement on the forecasted LCRs for Zone J and G-J Locality. Ultimately, this assumption was the key driver of the CY17-1 BSM evaluation results. The exclusion of the Indian Point units from the forecast led to a very low capacity margin in the G-J Locality, and increases in the energy prices over the MSP.

- The low capacity margin in G-J Locality resulted in high G-J and Zone J capacity prices (since Zone J prices were determined by the G-J Locality's Demand Curve).
- The relatively high net revenues of the Examined Facilities due to retirement of the Indian Point units resulted in lower UNCs for Examined Facilities.

These factors in combination with the cost advantages for projects that replace existing facilities and Additional CRIS MW projects resulted in the CY17 Berrians Project and the East River 6 Projects being exempt from the Offer Floor in the CY17-1 BSM evaluations.[42]

The NYISO performed the Part B test for three Examined Facilities in the CY17-2 settlement phase, and confidentially provided each developer its initial BSM determination. However, none of the CY17-2 Projects received a final determination as all three projects rejected their respective PCA for SDUs and Deliverable MW.

41 The average gas futures price over 2018/19 and 2019/20 capability years was $3.37/MMBtu (in CY17-1 BSM evaluation) and $3.36/MMBtu (in CY17-2 BSM evaluation), whereas the average price over the MSP years was $3.25/MMBtu (in CY17-1 BSM evaluation) and $3.51/MMBtu (in CY17-2 BSM evaluation).

42 See subsections IV.A.6 and IV.A.7.

Overall, we find that the CY17 Part B tests were performed using reasonable assumptions in accordance with the NYISO MST.

We identify an issue with the Tariff related to the assumed Starting Capability Period. Although we find that this issue did not affect the final determinations for the CY17 BSM evaluations, it affected the forecasted capacity prices and could, therefore, adversely affect the Part B tests in future BSM evaluations. Therefore, we recommend the NYISO modify the MST to allow more reasonable assumptions regarding the Starting Capability Period in future BSM evaluations.

V. PART B TEST INPUT – COST OF NEW ENTRY

The BSM exemption test requires the NYISO to estimate the annual levelized CONE of an Examined Facility for use as an input to the Part B test. The developers of the CY17 Projects provided cost information which was evaluated by the NYISO with the assistance of an engineering consulting firm. In some cases, the NYISO substituted a developer's identified cost estimates with one that the NYISO determined was more reasonable. This section evaluates key assumptions used in the CONE estimates.

A. Implications of Factors Identified in Section VII

This sub-section briefly discusses how factors identified in Section VII affected the estimated CONE of the CY17 Projects.

1. Implications of the 2017 Tax Cuts and Jobs Act

The NYISO modeled the reduction in federal corporate taxes (from 35 percent to 21 percent), elimination of state tax deductibility, and full expensing in the first year of operation for eligible costs (as applicable) in estimating the CONE of the CY17 Projects. The first two provisions increased the after-tax weighted average cost of capital ("ATWACC") of the CY17 Projects by up to 50 basis points.[43] As discussed in subsection VII.C, while the first two provisions affected the estimated CONE for all Examined Facilities, the NYISO allowed bonus depreciation only for eligible CY17 Projects whose developers indicated their ability to benefit from this provision. Bonus depreciation reduced the CONE of CY17 Projects by up to 14 percent.

2. Treatment of Examined Facilities Seeking Competitive Entry Exemption

In accordance with its tariff, the NYISO estimated the CONE for the CY17 CEE Projects (the CVEC Project and the BEC II Project) for use in the CY17-1 Part A and Part B evaluations.[44] Although the CY17 CEE Projects are in various stages of completion, the NYISO included the full embedded costs for these projects in the CONE estimates per its tariff definition for UNC. The BEC II Project was nearly complete at the time of CY17-1 evaluations, and the CVEC Project developers indicated that they have already incurred nine percent of the project costs.[45]

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43 See subsection V.B.2 for discussion of the NYISO's approach to determining the ATWACC for CY17 Projects.

44 See discussion in subsection VII.D.5.

45 See *Comments by Cricket Valley Energy Center, LLC on NYISO's Capacity Zone Creation /Zone Elimination Proposal*, dated January 3, 2018, available at: https://www.nyiso.com/documents/20142/1390753/Comments%20by%20Cricket%20Valley%20Energy%20Center%20LLC%20on%20NYISO%20on_off%20ramps.pdf/69dba2f9-f8d9-6814-5ba8-3b5f630506e2.

Therefore, including the costs that have already been incurred substantially increased the estimated CONE for the CY17 CEE Projects.

B. Assumptions Affecting CONE of Multiple CY17 Projects

This section discusses the general principles and methods used to estimate components of CONE for all the CY17 Projects.

1. Treatment of Pre-Existing and/or Common Facilities

The CY17 Berrians Project and the Linden Uprate Project will be located at sites with existing or recently-retired generators. A new project located on a site with existing units might use pre-existing equipment on the site, share pre-existing equipment with other generators at the site, and share new equipment with existing or future generators.

The MST requires the NYISO to estimate the CONE of an Examined Facility based on its "embedded" cost. This sub-section discusses the criteria used by the NYISO to estimate the embedded costs allocated to the Examined Facilities, when the costs are related to pre-existing and/or common (i.e., shared) facilities.

Pre-Existing Non-Common Facilities

Pre-existing non-common facilities include equipment that was originally built for another generator that is no longer in use. The NYISO estimated the embedded cost of pre-existing noncommon facilities at the Examined Facility site(s) based on their book values. The use of book values was consistent with the requirement to use embedded costs.

Pre-Existing Common Facilities

As a general matter, when a project is located at an existing plant that is owned by an incumbent generator, the project may take advantage of the economies of scale that come from using facilities that were purchased or constructed well before the project was conceived and that are still being used for other generators at the same site. For example, the new project may share labor costs, control room functions, interconnection facilities, and inventory capacity with other generators at the site. Such facilities are known as pre-existing common facilities.

To the extent that the developers plan to use pre-existing common facilities, the NYISO allocated costs from such facilities to the Examined Facilities only if additional costs would be incurred to expand the capacity of the common facilities. Hypothetically, if an on-site storage facility costing $100,000 would be expanded 50 percent at a cost of $40,000 to accommodate the needs of an additional project, $100,000 would be included in the CONE estimate for first project, while $40,000 would be included in the CONE estimate for the second project.

Similarly, to the extent that the Examined Facility resulted in an increase in the costs of operating the site (e.g. labor, materials), the additional operating costs were included in the CONE of the Examined Facility. We believe the NYISO's assumptions regarding pre-existing common facilities were consistent with the Tariff and are likely to produce CONE estimates that are consistent with the true economic cost of the new entry.

2. Cost of Capital

The NYISO used the cost of capital estimates submitted by the CY17 Projects' developers when they were reasonably consistent with the risk profile of the project and/ or were well-substantiated. The documentation reviewed by the NYISO to evaluate the reasonableness of the cost of capital estimates include credit agreements, offtake agreements, internal presentations and any hedging arrangements that the developer had in place. These contracts generally lowered the cost of financing a project, but included certain upfront costs (e.g., financing fees, cost of the hedging instrument), which the NYISO incorporated into its CONE estimates. The NYISO did not consider contracts that were not finalized at the time of the evaluation.

If a submitted estimate was unsubstantiated or needed to be updated, the NYISO estimated the project-specific weighted average cost of capital ("WACC") after considering:

- Publicly available information including regulatory filings, company financial statements and outstanding bond issues;
- The results of Capital Asset Pricing Model ("CAPM"), which was calibrated in a manner consistent with previous Demand Curve reset studies.

To the extent that firm-specific or project-specific information was unavailable or unsuitable for the WACC calculation for a particular Examined Facility, the NYISO updated and used values that were developed in relation to the latest Demand Curve reset study.[46] We find the cost of capital parameters used by the NYISO in the CY17 BSM evaluations to be reasonable.

3. Amortization Period

The estimated CONE of each CY17 Project was amortized over the project's economic life, which is the period over which an owner seeks to recover the project costs along with a return on investment. The assumed economic life affects the levelized CONE estimate in a significant manner. The NYISO evaluated the applicability of proxy parameters from the Demand Curve reset for the useful life and residual value for each of the CY17 Projects.

[46] The cost of capital estimates developed as part of the latest ICAP Demand Curve reset study that was filed on November 18, 2016 can be found at http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/Reference_Documents/2017-2021_Demand_Curve_Reset/Analysis%20Group%20NYISO%20DCR%20Final%20Report%20-%209_13_2016%20-%20Clean.pdf.

Two of the CY17 Projects are standalone peaking units, for which the NYISO assumed a 20-year useful life, consistent with the assumption for the Demand Curve unit. Two other projects involve installation of large combined cycle units (the CVEC Project) or a CT that would operate in conjunction with existing steam turbines (Linden Uprate Project). Both projects would be located at large generating stations, which tends to reduce operating costs of individual generators at the station. In addition, the Linden Uprate Project would also have access to revenues from sale of steam. These facilities can reasonably be expected to have a different long-term risk profile, longer useful life and/or a higher residual value when compared to a standalone, smaller units studied in the Demand Curve reset process. Consequently, the NYISO assumed a longer useful life and/or higher residual value than the Demand Curve unit. The NYISO assumed a longer useful life for the CHPE Project than the Demand Curve unit, consistent with what was used in the CY15 BSM evaluation.

As a general matter, Additional CRIS MW projects could involve replacement of older components/ practices with newer and more efficient ones, or repairs/additions of components that allow the generator to produce more output. A blanket assumption for economic life across all projects is not appropriate given the variation in investments that result in Additional CRIS MW. In its CY17 BSM evaluations, the NYISO compared the submitted values for physical life of the project against the remaining economic life of the generator (after considering future market conditions in electricity and/or steam markets). If the recently installed components are likely to be physically operable at the end of the economic life of the generating facility, the NYISO amortized the investment over the remaining economic life of the generation facility.

We find the NYISO's approach for estimating the economic life of CY17 Projects to be reasonable.

4. Interconnection Costs

Consistent with Commission directives in previous BSM evaluations, the NYISO used the Project Cost Allocations ("PCAs") for System Upgrade Facilities ("SUFs") and System Deliverability Upgrades ("SDUs") and the headroom payments from the CY17 Facilities Studies Reports to estimate the interconnection costs of the Examined Facilities.[47] The NYISO is responsible for developing the PCAs, so cost estimates were developed for each Examined Facility by the NYISO with input from the Connecting or Affected Transmission Owners ("TO") and the developer.

A developer must post financial security for the amount equal to its PCA in order to remain in the Class Year. If the actual cost of constructing the SUFs and/or SDUs is lower than the

47 See MST §23.4.5.7.3.3.

amount of Security, the developer is only responsible for the actual cost incurred.[48] The purpose of the PCA is to ensure that the developer is financially responsible for any interconnection costs, while the purpose of the BSM evaluation process is to estimate the expected cost of new entry of an Examined Facility. So, the differing purposes of the processes may justify the use of two estimates.

Although this issue neither impacted the CY17 BSM determinations in a significant manner, nor did it change the outcomes, it could nevertheless impact the NYISO's future BSM evaluations. Therefore, we recommend that the NYISO consider whether to modify its tariff to allow the BSM evaluation to develop interconnection cost estimates.

5. Interest During Construction

The NYISO estimated the Interest During Construction ("IDC") using the draw schedule and construction loan terms for CY17 Projects when the submitted information was well substantiated. In other situations, the NYISO used a default project's construction draw schedule and/ or the project-specific WACC that was derived based on the principles outlined in V.B.2.[49] Some of the CY17 Projects did not require any significant build time compared to new generation projects. Hence, the IDC calculation was not necessary for all Examined Facilities.

C. Assumptions Affecting CONE of Individual CY17 Projects

1. CONE of the Champlain Hudson Power Express Project and Cricket Valley Energy Center Project

The NYISO estimated the CONE for the CHPE and CVEC Projects using methodologies developed during the CY12 and CY15 BSM evaluations, although the NYISO considered additional and updated information that was submitted by the project developer in the CY17 process.[50]

2. CONE of the CY17 Berrians Project

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48 See OATT §25.8.6.2.

49 For instance, the DCR consultants developed default draw schedules for CCs and CTs for the purpose of estimating the Gross CONEs in the 2016 ICAP Demand Curve Reset Study. See https://www.analysisgroup.com/globalassets/content/insights/publishing/analysis_group_nyiso_dcr_final_report_9_13_2016.pdf.

50 See the MMU report "Assessment of the Buyer-Side Mitigation Exemption Tests for the Class Year 2012 Projects" available at: https://www.nyiso.com/documents/20142/3025245/MMU%20Report%20on%20CY%202012%20BSM%20Tests.pdf/6942f5b5-e9e8-b344-246a-d45b4d6287e9

The CY17 Berrians Project would be developed at a site with generators that currently possess CRIS rights, of which 504.4 MW were studied in the Class Year process as being transferred to the CY17 Berrians Project. Therefore, although the CY17 Berrians Project is a 508 MW (ICAP Summer) facility, the developer submitted a request for only 3.6 MW of CRIS rights.

The NYISO also analyzed and compared the economics of a) the above-described proposed new generation entry and removal from the market of existing generators at the site, and b) the continued operation of the existing generators. Information from that comparison was evaluated in development of the estimated CONE of the CY17 Berrians Project.[51] We find the NYISO's approach for estimating the CONE of the CY17 Berrians Project to be reasonable for the purpose of its BSM evaluation.

3. CONE of the Linden Uprate Project

The NYISO estimated the CONE of the Linden Uprate Project using the incremental capital and fixed O&M costs (relative to the configuration and operation of existing units at the site) associated with adding the new unit at the site. In addition, the NYISO adjusted the costs of shared facilities and services in accordance with the principles outlined in subsection B.1. We find the NYISO's approach for determining the CONE of the Linden Uprate Project to be reasonable.

4. CONE of Additional CRIS MW Projects

MST §23.4.5.7.6.1 indicates that the net CONE for Additional CRIS MW projects will be based on the revenues and costs associated with the requested increase in CRIS MW when the Examined Facilities meet certain criteria. This provision was applicable to both the Additional CRIS MW requests in CY17, since they were for generators that were exempt from Offer Floor mitigation because they had already been in service at the time of the original implementation of BSM rules.[52]

The incremental cost of an Additional CRIS MW project is equal to (a) the investment cost, plus (b) any increases in fixed O&M costs, minus (c) any avoided cost the developer would have incurred if the uprate were not undertaken.[53] In the CY17 BSM evaluation of Additional CRIS

51 As a general matter, to the extent that existing generators at a site are economic to operate, we believe it is reasonable for the CONE of a new project that replaces existing generators to be increased by the potential value that could be derived from continued operation of the existing generators at the site. Such an adjustment to the CONE of the replacement project would enable a direct comparison of the project's UNC with the ICAP price forecast in the Part B test.

52 See Section 23.4.5.7.5 of the Services Tariff.

53 For example, suppose the owners of a 200 MW combustion turbine unit replace existing turbine blades with newer blades and as a result, secure an additional output of 10 MW from the unit. Further, suppose annual

MW projects, the NYISO evaluated the submitted investment costs to determine whether they would be sufficient to effect the claimed increase in capacity at the generator. The NYISO validated changes in O&M costs by considering the nature of the upgrade and historical information related to plant maintenance over several years.

D. Conclusions – Cost of New Entry

We reviewed detailed information on the NYISO's estimates of the annual levelized CONE values for the CY17 Examined Facilities. We find that the NYISO's estimates were reasonable and made in accordance with the Tariff.

fixed maintenance costs of the unit would be \$5 million (i.e. \$25 per kW-year) without the upgrade and \$4.62 million (i.e. \$22 per kW-year) with the upgrade. If the investment cost of the upgrade and the carrying charge for the investment were \$4 million (i.e. \$400 per kW) and 20% respectively, the CONE of such an Additional CRIS MW project would be calculated as \$400 x 20% + \$22 - \$25 = \$77 per kW-year.

VI. PART B TEST INPUT – NET REVENUE

The forecasted net Energy and Ancillary Services revenue is a key component of the Part B test, since a new project developer expects to recoup a large share of its investment from future energy and ancillary services revenues.[54] Estimating the net revenue of a new generator is a complex endeavor, requiring the use of models to estimate future LBMPs at which the new facility would sell its output and forecast when the Examined Facility will be scheduled. Likewise, estimating the net revenue of a new transmission line is also a complex endeavor, requiring additional models to estimate the line operator's future cost of procuring electricity and forecast how the line will be operated based on the estimated price spread across its termini.

We reviewed the assumptions used by the NYISO to estimate the net revenues for the CY17 Examined Facilities to determine whether they were reasonable and consistent with the Tariff. We find that the NYISO used assumptions that were reasonable and tariff compliant. This section is divided into the following sub-sections:

- Implications of key assumptions described in Section VII
- LBMP estimation model – This component of the net revenue model forecasts market clearing prices where the Examined Facility would sell electricity. For a transmission line, prices must also be estimated where the line operator would withdraw electricity.
- Scheduling models – This forecasts how the Examined Facility will be scheduled based on the LBMPs estimated by the NYISO, the costs of the Examined Facility, and other factors that affect scheduling.

The conclusion discusses the overall results of the net revenue evaluation.

A. Implications of Assumptions Discussed in Section VII

This sub-section discusses how factors identified in Section VII affected the net revenue estimates for the CY17 Examined Facilities.

1. Starting Capability Period of Summer 2020

The Starting Capability Period is important because the assumed timing of entry affects the resource mix, gas futures prices and the load forecast, which are key drivers of the LBMP price forecast that is used to calculate net revenue.[55] Under the current Tariff, all CY17 Projects are assumed to enter in Summer 2020, although it would be more reasonable to assume that some projects would enter later and some of them much earlier (e.g. the Additional CRIS projects). If

54 Net revenues are an input to the Unit Net CONE, which is directly used in the Part B test. See *BSM Numerical Example*, Section 3.2.

55 The assumption regarding the Starting Capability Period is discussed in further detail in Sub-section VII.A.

the Starting Capability Period was pushed back to a more realistic date, the assumed retirement of Indian Point would lead to increases in LBMPs that would result in higher forecasted net revenues for several Examined Facilities, which would reduce their Unit Net CONE values.

The Starting Capability Period also had other implications for the CHPE Project's cost of purchasing electricity from the HQ region for export to New York City. In general, adding supply to the HQ region would tend to reduce the cost of energy for the CHPE Project, while additional demand would tend to raise the cost of energy. In 2020/21 and 2021/22, it is anticipated that supply additions will exceed the forecasted growth in demand in the HQ region. However, in 2022/23 the capacity margin in HQ is expected to tighten relative to the prior two years.[56] Thus, assuming an early Starting Capability Period of Summer 2020 would tend to overestimate the available energy that could be exported from the HQ region to neighboring markets. This affects estimated net revenues by underestimating cost of energy for the CHPE Project. Hence, all else being equal, modifying the Starting Capability Period to a more realistic date would reduce the net revenues for the CHPE Project.

2. Capacity Assumed to be In-service During the Mitigation Study Period

The NYISO forecasted LBMPs using the following assumptions for deactivated units and units under a deactivation notice: [57]

- For the CY17-1 BSM evaluation, over 160 MW (ICAP Summer) from units that are currently in a Mothball Outage ("MO") or an ICAP Ineligible Forced Outage ("IIFO") would not offer capacity during the MSP if they had a negative NPV from returning to service. For the CY17-2 BSM evaluation, over 280 MW (ICAP Summer) from units that are currently in a MO or IIFO would not offer capacity if they had a negative NPV from returning to service;
- Over 1000 MW of capacity (ICAP Summer) from each Indian Point unit would be retired by the end of 2019/20 and 2020/21. The NYISO excluded this capacity based on publicly available information that the units would cease operations.

The exclusion of Indian Point had a significant impact on the LBMPs and net revenues, and resulted in lower UNCs for the Examined Facilities. Including the other deactivated units would have raised net revenues by a relatively small amount, since units in this category are likely to have low capacity factors and correspondingly low impacts on forecasted LBMPs.

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56 See 2018 Long-Term Reliability Assessment, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf.

57 These assumptions are discussed in further detail in Sub-section VII.B.

B. General Criteria for Making Adjustments to the Net Revenue Model

As in previous BSM evaluations, the NYISO started with the suite of models that were used to derive the currently-effective Demand Curves, and then the NYISO made several changes that were suited to the CY17 BSM evaluation.[58] The Commission has provided guidance regarding when it is appropriate to make adjustments to the net revenue model. For example, the Commission approved the NYISO's use of natural gas futures prices in the net revenue model for BSM determinations even though historic natural gas prices had been used to establish the Demand Curves that were effective because of the "differing objectives" of the two models.[59] Hence, it is appropriate to make adjustments to the net revenue model when there is a strong rationale for distinguishing between the Examined Facility and the Demand Curve proxy unit.

In the evaluation of each Examined Facility, the NYISO made adjustments to the net revenue model to address factors that are relevant to the net revenues of the particular project but not the proxy unit used to establish the currently-effective Demand Curves. The remainder of this section discusses the NYISO's methodology and its assumptions for estimating the net revenues for the CY17 Projects.

C. LBMP Estimation Model

For each settlement phase of the CY17 BSM evaluations, the NYISO utilized a two-step procedure for forecasting the LBMPs for the MSP and the Capability Years 2018/19 (only for CY17-1 BSM evaluation) and 2019/20.[60] The NYISO's approach entailed using the outputs of an econometric model and the GE-MAPS model in a sequential manner to forecast the LBMPs.

58 For example, previous METs adjusted net revenues to account for the fact that the Examined Facility would be interconnected at a specific location on the 345kV system or 138kV system in New York City.

59 This Commission Determination was made in response to the complaint that use of gas futures in a MET constituted an "apples to oranges" comparison. See Astoria Generating Company, L.P., et al. v. New York Independent System Operator, Inc., 139 FERC ¶ 61,244 (2012), PP. 108-109:

> [W]e agree with NYISO that the objectives underlying the calculation of Default and Unit net CONE differ and that these differing objectives justify using natural gas price forecasts from different sources in calculating net energy and ancillary service revenues in the mitigation test versus in the demand curve reset process…the objective underlying the demand curves is to provide a reasonable opportunity for an efficient new entrant to recover its costs over its lifetime, and that using historical natural gas prices is likely to provide an accurate estimate of average of net energy and ancillary service revenues on average over time…By contrast, [the Part B] test is focused on a shorter time period…We agree with NYISO that natural gas futures prices are likely to provide the more accurate forecast of future natural gas prices in the near term individual years than would historical natural gas prices.

60 The NYISO used the forecasted or historical (as available at the time of analysis) LBMPs for Capability Years 2018/19 through 2020/21 to determine the net energy and ancillary services revenue for the demand curve unit at the tariff defined Level of Excess conditions. The projected net revenues were then used to forecast the ICAP reference points for the years before and during the MSP.

In its previous BSM evaluations, the NYISO's forecasted LBMPs were based in part on an econometric model that was developed by its consultants as part of the 2013 Demand Curve reset study. However, in the 2016 Demand Curve reset study, the NYISO's consultants assumed that the prior year prices provide a reasonable basis for the expected revenues (after adjusting for LOE conditions) for the following year, and as such, did not use an econometric model to forecast LBMPs for future years.[61] Therefore, in the absence of a comparable model from the 2016 study, the NYISO developed and validated a new econometric model using training data from 2007 to 2017 to predict hourly zonal LBMPs for Capability Years 2018/19 – 2021/22.[62, 63] The NYISO developed a neural network model whose inputs included gas prices, load, and temperature among other variables.

The NYISO adjusted the output of the econometric model (hourly zonal LBMPs) for changes in resource mix during the future years, and the differences in zonal and nodal pricing using results from the GE-MAPS simulations.[64] The NYISO used the LBMPs from GE-MAPS to estimate ratios (at a month-hour level) for scaling the output of the econometric model to forecast the LBMPs for use in the scheduling models.

The rest of this section describes other assumptions that the NYISO made in forecasting market clearing prices for the CY17 BSM evaluations.

1. Gas Futures Prices

For the CY17 BSM evaluations, the NYISO used gas futures prices to forecast the gas prices, LBMPs and the net revenues for the Examined Facilities and the Demand Curve unit. This is consistent with the approach the NYISO utilized in the Part B tests in previous Class Years. The Forecasted LBMPs for projects in Zone G were primarily based on gas prices at Iroquois Zone 2, while forecasted LBMPs for projects in Zone J were primarily based on gas prices at Transco Zone 6 (NY).[65]

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[61] Given the mechanism to update ICAP demand curves annually, the demand curve consultants did not forecast the LBMPs for the future years during which the demand curves would be effective.

[62] The NYISO identified certain limitations with the 2013 econometric model such as: a) overfitting leading to counterintuitive movements in forecasted LBMPs in response to changes in gas prices, and potentially suboptimal forecasts when calibrated using unusual market outcomes in winter 2013/14 and 2014/15, b) limited validation or evaluation of the model performance using actual price series.

[63] The NYISO used the observed data from 2017/18 to validate the performance approach of the trained model.

[64] In addition to modeling the entry of CY17 Projects, the MAPS simulations also modeled the retirement of Indian Point units.

[65] For CY17-1 evaluation average monthly futures prices traded over 05/03/2018 through 06/01/2018 were used. For CY17-2 evaluation average monthly futures prices traded over 03/04/2019 through 04/02/2019 were used.

2. RGGI and WCI Futures Prices

Operating costs for power plants in the Regional Greenhouse Gas Initiative ("RGGI") or Western Climate Initiative ("WCI") member states include the costs associated with obtaining carbon allowances to cover their CO2 emissions.[66, 67] LBMPs generally reflect the marginal costs of gas-fired generation, including the cost of RGGI allowances. RGGI allowance futures prices indicate considerable differences between the historic prices and prices during the MSP. No adjustment was made to the net revenues of the CY17 gas-fired projects to account for expected increases in RGGI allowance prices.[68]

As a transmission line, the CHPE Project's net revenues would be affected by the impact of carbon allowance costs on prices where it would purchase and sell electricity. Consistent with previous BSM evaluations, the NYISO adjusted LBMPs to reflect the effects of differences (between historic and future years) in the applicable carbon allowance costs where the CHPE Project would sell and purchase electricity.

We support the NYISO's adjustment of the expected LBMPs to account for carbon allowance price futures.

D. Scheduling Models

The following subsections discuss the scheduling models the NYISO used for estimating the net revenues of the CY17 Examined Facilities.

1. Cogeneration Plants

The Linden cogeneration and East River 6 units in Zone J are cogeneration plants, so the operating characteristics of these facilities are substantially different from the peaking plant used to establish the currently-effective ICAP Demand Curves. Cogeneration plants generally offer into the energy market in accordance with steam offtake contracts, so their response to energy

66 The Ontario government has indicated that it may exit the WCI. However, given the relatively recent nature of this development, the NYISO could not consider it in the CY17-1 BSM evaluations. Nevertheless, reversing the WCI carbon price adjustment would not have impacted the CY17-1 BSM determinations. The NYISO used the forecasted WCI prices from *Ontario Energy Board's Long-term Carbon Price Forecast, date* 19 July 2017.

67 Consistent with CY17-1 BSM evaluation, the NYISO used the forecasted WCI prices from *Ontario Energy Board's Long-term Carbon Price Forecast* for CY17-2 BSM evaluation. However, due to recent cancellation of the cap and trade regulation by the Ontario government and implementation of federal carbon tax by the Canadian government, using the federal carbon tax instead of the WCI prices would have been more appropriate. Nonetheless, using the federal carbon tax would not have changed the outcome of the CY17-2 BSM evaluation.

68 This is because the net revenue effects for combined cycle generators of higher electricity prices in southeast New York will largely be offset by the effects of higher allowance procurement costs.

prices in the short term may not be similar to combustion turbine or combined cycle units. Therefore, modeling the production of such facilities based on the model used to project the net revenues for the Demand Curve unit would be inconsistent with actual operations of cogeneration plants.

The NYISO estimated the incremental revenues from the three cogeneration Examined Facilities by calculating the difference between two scenarios. The first scenario utilized the heat rate curves of the facilities at the site prior to the uprates to forecast the net revenues. In the second scenario, the NYISO used the adjusted the heat rate curve for greater efficiency and/ or additional capacity associated with the uprates to forecast net revenues over the MSP. The NYISO considered the nature of the uprate and estimated the net revenues associated with the Examined Facility by assuming:

- that the commitment of cogeneration plants during the MSP would be similar to the observed energy market schedules of these units over three recent Capability Years, or
- that the cogeneration plant would be committed to satisfy its steam obligations and additional capacity scheduled for energy if deemed to be profitable given the spread between LBMPs and fuel prices.

2. Combined Cycle and Combustion Turbine Examined Facilities

The CY17 Berrians Project and the Bayonne Energy Center II ("BEC II") Project are combustion turbine facilities, and the CVEC Project is a combined cycle facility. The NYISO estimated the net revenues for these units using the scheduling models its consultants developed as part of the latest Demand Curve reset study.[69] The scheduling models for these units determine the optimal set of hours for running the unit each day based on DAM and RT LBMPs and Ancillary Services prices, considering various categories of costs (including fuel costs based on gas and oil prices, start-up costs, balancing charges, emissions allowance costs) and constraints on operation of the unit (e.g. start time, run hour limits).

3. CHPE Scheduling Model

The NYISO's model assumed the CHPE Project would export to New York City when the forecasted day-ahead LBMP at the CHPE Project's interconnection node in Zone J was greater than the expected cost of purchasing power in the HQ region plus the applicable transmission service charge. The underlying assumptions and methodology of the NYISO's net revenue model for the CHPE Project was discussed in our CY12 BSM evaluation report. In its CY17 BSM evaluations, the NYISO updated the following inputs to its net revenue model: peak load and energy consumption forecasts, energy and capacity contacts with Ontario, forecasted capacity additions, forecasted LBMPs at locations where exports from HQ sink in, transmission

[69] The assumptions and methodology for the Demand Curve scheduling models are described in *Study to Establish New York Electricity Market ICAP Demand Curve Parameters*, dated June 23, 2016.

service charges, RGGI and WCI allowances' price forecast, and the USD/ CAD exchange rate. In addition, the NYISO also considered the effects of the Electricity Trade Agreement ("ETA") between HQ and Ontario that provides Ontario with a firm arrangement to purchase 2 TWh of electricity every year from Quebec from 2017 through 2023 at a set contract price.[70] This methodology is consistent with the Tariff's guiding principles to determine a UDR project's likely projected net Energy and Ancillary Services.

Overall, we find that the NYISO utilized reasonable methods for forecasting the net revenues of the CY17 Projects.

E. Conclusions – Net Revenues

We reviewed detailed information on the NYISO's estimate of the reasonably anticipated net revenues of the CY17 Examined Facilities. We find that the NYISO's estimates were reasonable and in accordance with the Tariff. The net revenues are used in the calculation of the Unit Net CONE, which is used in the Part B test as described in Section IV.

70 The ETA also allows Ontario to recall 0.3 TWh of electricity from Quebec each year and requires it to provide 500 MW of excess winter generating capacity to Quebec from 2017 through 2023. See page 1-2 of http://www.fao-on.org/web/default/files/publications/Electricity%20April%202018/ElectricityTrade0418.pdf

VII. Assumptions Affecting Part A and Part B Tests

This section of the report discusses key assumptions that affect multiple components of the CY17 BSM evaluations.

A. Starting Capability Period of Summer 2020

The Starting Capability Period is the Capability Period in which the Examined Facilities are assumed to begin operating and offering capacity for the purposes of the BSM determinations. The Tariff requires the NYISO to assume that all Examined Facilities will be in service three years after the start of the Class Year, so the NYISO assumed that CY17 Projects will be in service beginning in May 2020.[71]

The Starting Capability Period is important because the timing of entry affects a number of inputs to the Part A and Part B tests, such as the load forecast, units assumed to be in service, ICAP reference points and the Unit Net CONE values.[72, 73] Consequently, a fixed Starting Capability Period could produce unreasonable ICAP price forecasts when actual commercial operation dates ("CODs") are misaligned with the assumed COD.[74] In addition, if the Starting Capability Period is not aligned with the CODs of Examined Facilities, it might disadvantage Examined Facilities that are likely to be operational earlier than other projects.[75]

The three-year rule was implemented to increase transparency and the certainty for developers and market participants regarding the assumptions used in the BSM evaluations and to avoid gaming of the timing a project's identification of its COD. However, this approach results often in a misalignment of the Starting Capability Period with the likely CODs of Examined Facilities in two ways:

71 See MST §23.4.5.7.2.

72 The effects of the Starting Capability Period on the Part A and Part B tests are discussed in Sub-sections III.A.1, IV.A.1, and VI.A.1.

73 In CY17, the assumed Starting Capability Period had a significant bearing on the NYISO's ICAP price forecast particularly due to changes in a) the LCRs determined for purposes of the BSM evaluations (which were driven in large part by the Indian Point retirement), and b) the ICAP reference points over the MSP.

74 Previous MMU BSM Reports have identified additional problems with the Starting Capability Period assumption. For example, if the Starting Capability Period is significantly earlier than an Examined Facility's likely COD, it can depress the ICAP price forecasts and inflate the Unit Net CONE, thereby increasing the likelihood of mitigating an economic resource. Similarly, a delayed Starting Capability Period could inflate load and ICAP price forecasts in the Part A and Part B tests, thereby increasing the likelihood of exempting an uneconomic unit. See CY12 BSM Report at page 43-44.

75 For instance, assuming that a new generator will begin operating at the same time as an Additional CRIS MW project may result in an unrealistically low capacity price forecast if it includes the new generator.

- First, the COD of an Examined Facility depends on the underlying technology and its timeline for securing the required permits. As a result, assuming that all Examined Facilities will begin operations three years from the calendar year of the Class Year is likely to be incorrect for several Examined Facilities.
- Second, the tariff provision for determining the Starting Capability Period is tied to the start of the Class Year and does not account for the time required to perform CY studies. Therefore, in cases where the developer's decision to move forward with the project is contingent on the PCA and/or the determination, the Starting Capability Period is much earlier than the likely commercial operation date.

In addition, the developers of the CY17-2 Projects did not learn their project's final Class Year PCA of interconnection costs and their BSM determinations until the second quarter of 2019 — less than a year before the Starting Capability Period. The BSM measures are intended to provide a developer with the exemption test results at an early stage in the development a new facility, since a competitive supplier might not move forward with such a large investment if it was not reasonably certain to receive capacity market revenues. In order for some of the CY17 Examined Facilities to begin operating by May 2020, construction would have had to begin before they learned their respective interconnection costs or BSM exemption test results.

Hence, we recommend the NYISO modify its Tariff provisions related to the Starting Capability Period to improve alignment with the likely CODs of the Examined Facilities. A potential alternative to the three-year rule could be to assume a COD that is based on the underlying technology of the Examined Facility.[76] Such a technology-specific start date rule could provide that that date be adjusted as needed to reflect an Examined Facility's progress in meeting its permitting milestones and the timing of conducting the CY studies.[77]

B. Forecasted ICAP Reference Points

The NYISO's tariff requires it to forecast the ICAP reference point for the MSP to develop the ICAP Demand Curves to be used in the METs.[78] For its BSM evaluations in each settlement phase of CY17, the NYISO identified the Gross CONE, net energy and ancillary services

76 For instance, the Energy Information Administration in its NEMS model assumes a lead time that varies from two years (for Combustion Turbine and Solar PV facilities) to four years (for Biomass, Coal and Offshore wind facilities) for most of the generation technologies.

77 The NYISO has proposed multiple options for revising the rules regarding the MSP at a stakeholder meeting. See presentation to NYISO ICAP Working Group, *Enhancements to the Mitigation Study Period for Buyer-Side Mitigation*, by Nathaniel Gilbraith and Scott Godfrey (October 27, 2016).

78 MST Section 23.4.5.7.15.3.

revenue offset, and the winter summer ratio by updating the values for purposes of the BSM evaluation and consistent with the ICAP Demand Curve rules.[79]

The NYISO inflated the costs of the demand curve peaking unit using the applicable Inflation Index.[80] In addition, the NYISO also adjusted the marginal tax rates (see subsection C) to reflect the impact of the recently enacted US tax law on the net CONE of the Demand Curve unit.[81] The currently effective Demand Curves are valid until the first year of the MSP (2020/21), and the Tariff only allows for certain formulaic annual updates (that do not include changes to financial parameters) to project the ICAP reference point for 2020/21.[82] Hence, the NYISO incorporated changes to the tax rates only for the second and third years of the MSP (*i.e.*, 2021/22 and 2022/23).

The NYISO forecasted the zonal LBMPs for the years 2018/19 through 2022/23 in CY17-1 BSM evaluation and 2019/2020 through 2022/23 in CY17-2 BSM evaluation using the econometric model and GE MAPS.[83] The NYISO utilized the forecasted LBMPs in conjunction with the prescribed level of excess and the dispatch model that were developed as part of the 2016 DCR study to estimate the yearly EAS offset of the DC unit.

Overall, the projected Zone J ICAP reference points in CY17-1 were $186, $170 and $171 per kW-year for the first, second and third years of the MSP respectively. The Zone J ICAP reference points in CY17-2 were $184, $170 and $174 per kW-year for the first, second and third years of the MSP respectively.[84]

C. Implications of the 2017 Tax Cuts and Jobs Act

A number of provisions of the recently-enacted tax law Tax Cuts and Jobs Act ("TCJA") affect the estimated CONE of new builds. Hence, the TCJA is likely to impact the CONE of the Examined Facilities and the CONE of the Demand Curve utilized for purposes of the BSM examination. In this subsection, we discuss the provisions of the TCJA relevant to the MET, and the NYISO's methodology for incorporating them.

79 See section 5.1 of the *BSM Narrative and Numerical Example.*

80 Section 23.4.5.7.15.

81 The Tax Cuts and Jobs Act of 2017, Pub.L. 115-97 ("TCJA").

82 See Section 5.14.1.2.2.1 of the Services Tariff.

83 See subsection VI.C.

84 The minor differences in Zone J reference point across the CY17-1 and CY17-2 BSM evaluations is primarily due to the difference in the gas futures prices as discussed in Section IV.A.8.

1. Corporate Tax Rate

The TCJA lowered the corporate tax rate from 35 percent to 21 percent. This provision impacts the CONE of new builds in two ways.[85] First, the lower tax rate increases the project's after-tax cash flows available for distribution to the investors. Therefore, holding other factors constant, this would decrease the annual carrying charge rate related to the capital costs.[86] Second, the lower tax rate reduces the interest tax shield resulting from the project debt. As a result, the after-tax weighted average cost of capital ("ATWACC") of the investment would increase.[87] The net impact of these two countervailing factors would be to lower the annual carrying charges of the capital costs. The magnitude of the net impact would vary by project and depends on additional factors that include the leverage ratio, the cost of debt and the depreciation schedule of a project.

Since this provision of the TCJA can be expected to benefit all new builds, the NYISO incorporated the lower tax rate in its CONE estimates for the Examined Facilities, and in its forecasted ICAP reference point for the second and third years of the MSP.

2. Full Expensing of Equipment

The after-tax cash flows to equity investors are impacted by the depreciation schedule that is used to calculate the income taxes. Previous and the current Demand Curves studies and BSM evaluations utilized the MACRS depreciation schedules for each technology in accordance with the federal tax code. The TCJA contains a provision that allows for full expensing of eligible capital costs in the first year of operation for projects that enter into service prior to December 31 2022.[88] Opting for full expensing of capital costs in the first year could lower the CONE of the project by up to 14 percent . However, other provisions of the TCJA could limit the ability of investors to monetize this larger offset to income taxes.[89]

85 The TCJA contains fundamental changes to the Internal Revenue Code, and as such, there are several ways in which the law is likely to impact the cost of capital. However, the TCJA was enacted late 2017. Hence, the impacts of the legislation on investment and consumption decisions of various entities in the financial markets were unlikely to be discernable through market data at the time of the NYISO's BSM evaluations. Consequently, the NYISO did not consider other effects of the tax reform in its CY17 MET.

86 In addition to the capital costs-related charges, the annual levelized carrying charges also include fixed O&M, property taxes, and insurance payments among other costs.

87 The ATWACC can be calculated as (Debt Fraction) x (Cost of Debt) x (1 – Tax Rate) + (Equity Fraction) x (Cost of Equity).

88 The percentage of depreciable costs that could be deducted in the first year of operation begins to step down after 2022. This percentage decreases by 20 percentage points for each subsequent year after 2022 and phases out completely by the end of 2027. See page 9 of https://home.kpmg.com/content/dam/kpmg/us/pdf/2018/01/tnf-power-utilities-new-law.pdf

89 Other provisions of TCJA that could reduce the potential benefit include limits on interest deductions on debt and usage of net operating losses to reduce income.

Given the limited window for commencement of project operations and the practical limitation on the ability to monetize the tax depreciation benefits, the NYISO allowed for full expensing in the first year only for eligible CY17 Projects whose developers indicated their ability to benefit from this provision of the TCJA.

The next reset study is for the ICAP Demand Curves for 2021/22 through 2025/26, while this benefit would step down beginning 2023. Hence, it is unclear whether this tax law provision would affect the cost of new entry for the Demand Curve unit in the next reset. Accordingly, the NYISO did not incorporate full expensing of eligible capital into its forecast for the ICAP reference point for the MSP years in which the updated ICAP Demand Curves will be in effect (i.e., the second and third years of the MSP).

3. State Tax Deductibility

The NYISO used a composite tax rate of 45.37 percent for units located in New York City and 39.62 percent for all other units in its previous BSM evaluations and Demand Curve reset studies. The composite tax rate assumes that state and city tax payments are deductible from the federal taxable income. However, under the TCJA state taxes are not deductible for certain entities. Therefore, the NYISO adjusted the composite tax rate and applied a rate of 36.95 percent for units in located in New York City and 28.10 percent for all other units in its CY17 BSM evaluations and for forecasting in the ICAP reference point for the last two years of the MSP.

D. Capacity Assumed to be In-service During the Mitigation Study Period

The BSM exemption test requires the NYISO to project capacity prices as much as six years into the future. The set of generators that is assumed to be in service is important because the more capacity that is assumed to be in service, the lower the projected capacity prices. Consequently, over-estimating the amount of in-service capacity increases the likelihood of mitigating an economic project, while under-estimating the amount of in-service capacity may lead to under-mitigation. The capacity price forecast is very sensitive to the amount of capacity that is assumed to be in service. A 100 MW adjustment in UCAP changes Zone J prices by up to $17 per kW-year UCAP in the CY17-1 Part A test.

The LBMP forecasts are also affected by both the quantity of in-service resources and the anticipated capacity factor of the resources. High-capacity factor resources (e.g., current or prior CY Projects) have more impact on LBMPs than low-capacity factor resources (e.g., units in a Mothball Outage). The LBMP forecasts are a key input to the energy and ancillary services net revenues, which are used to calculate Unit Net CONE.

In this sub-section, we discuss the treatment of several categories of units in the NYISO's ICAP price forecasts and LBMP forecasts for CY17 Examined Facilities. We also identify areas where the Tariff or the current procedures for determining the in-service capacity should to be modified.

1. Deactivated Units, Retiring Units and Units Transferring CRIS Rights

In the CY17 BSM evaluations, the NYISO implemented new tariff provisions that govern the treatment of capacity from existing resources and inclusion/ exclusion of certain categories of resources from the ICAP and energy forecasts.[90] The inclusion/ exclusion rules are intended to allow for inclusion in forecast the resources that are reasonably expected to be available during the MSP.

The NYISO included most facilities classified as Existing Generating Facilities in the most recent Gold Book.[91] This sub-section discusses the assumptions underlying inclusion of other categories of generation and exclusion of certain existing facilities in the NYISO's capacity and LBMP forecasts for the CY17 MET.

Deactivated Units – These comprise resources that are in a Mothball Outage or an ICAP Ineligible Forced Outage ("IIFO") or resources that have recently retired. These resources currently possess CRIS rights, but are not operating and retain the ability to return to service during the MSP. The NYISO considered over 160 MW (Summer ICAP) in CY17-1 BSM evaluation and over 280 MW in CY17-2 BSM evaluation of such resources in Zone J, and included the resources that were determined to have a positive net present value in case they returned to service. The NYISO excluded resources that were in an IIFO as a result of Catastrophic Failure.

Retiring Units – In the CY17 BSM evaluations, the NYISO reviewed publicly available information that indicated whether some of the units currently operating are likely to retire before or during the MSP. Accordingly, the NYISO excluded 2056 MW (Summer ICAP) of Indian Point Capacity from the G-J Locality during the second and third year of the MSP its forecast for its CY17 BSM evaluation.

Units Transferring CRIS Rights – The CY17 Berrians Project involves transferring CRIS rights from existing units at the Astoria site to the Examined Facility. Hence, the NYISO excluded CRIS-adjusted DMNC of the existing units from its ICAP price forecast.

90 See MST §23.4.5.7.15.4-7.

91 See Table III-2 of the 2018 Gold Book for CY17-1 evaluation and Table III-2 of the 2019 Gold Book for CY17-2 evaluation. These resources possess CRIS rights, and are currently operating or may be in a Forced Outage or Inactive Reserve status, and are referred to as "Existing Units" (see MST §23.4.5.7.15.4).

The NYISO's new tariff corrected a substantial deficiency in the treatment of deactivated resources (and other categories of resources). We find that the NYISO's treatment of deactivated units, retiring units and units transferring CRIS rights to be compliant with its Tariff.

2. Existing Units at Risk of Retiring or Mothballing

The NYISO, in accordance with its Tariff, included all Existing Units in its price forecasts.[92] However, several capacity suppliers that are currently operating may choose to mothball or retire if capacity prices drop to levels that are insufficient to cover their fixed operating costs. Therefore, it is unrealistic to assume that all Existing Units will continue to operate during the MSP regardless of how low the forecasted prices are. However, the NYISO's current Tariff does not afford it the opportunity to consider the economic circumstances of the resources while developing the price forecasts.

In the CY17 BSM evaluation, the capacity price forecast for NYCA was well below than the retirement going-forward costs ("GFCs") of some existing resources in those areas. Although this issue did not affect the ultimate outcome of the BSM evaluations, unrealistically low price forecasts could act as a barrier to new entry in future Class Years. Therefore, we recommend the NYISO work with its stakeholders to develop reasonable criteria for treatment of Existing Units that are at risk of retiring or mothballing.

3. Prior Class Year Projects in the Interconnection Queue

The BSM exemption test requires the NYISO to estimate the effects on capacity and energy prices of prior CY projects in the Interconnection Queue ("Prior-CY Projects") that accepted their PCA in a previous Class Year but have not begun construction. The developer of a new project must post security for the amount of the PCA, but there is no guarantee that such a project will eventually be built.[93] The assumptions regarding such projects are important because over-estimating the amount of in-service capacity tends to depress the capacity price forecast and the LBMP forecast. Since new projects usually have high capacity factors, over-estimating the amount of new in-service capacity will tend to have large effects on the LBMP price forecast, which will also tend to inflate the UNC of the Examined Facilities.

The NYISO's tariff does not prescribe any specific assumptions for the treatment of Prior-CY Projects in the BSM exemption tests. Hence, it is important to use a reasonable approach for

92 See MST §23.4.5.7.15.4.

93 In some cases, the PCA may be very small relative to the overall investment, so there is little cost to the developer of remaining in the queue. In other cases, a project may remain in the interconnection queue for more than a year with little risk to the developer that it might lose a portion of its deposit if the project does not ultimately move forward.

treatment of these projects in both the ICAP forecast as well as the net revenue calculations. The NYISO's treatment of these projects is described below.

Exempt Prior-CY Projects – Prior-CY Projects that were determined to be exempt were included in the price forecasts. All exempt Prior-CY Projects have entered the market.

Mitigated Prior-CY Projects – For Prior-CY Projects that were mitigated, the NYISO included the project in the price forecasts based on whether it was reasonably likely that the project would be built under the circumstances modeled in the CY17 BSM evaluation. The NYISO assumed the project will be built if: (a) the project was under construction, (b) the developer has made some other significant irrevocable financial commitment towards the project, or (c) the developer would earn sufficient forecasted revenues from the NYISO markets for it to be profitable for the developer to move forward.[94]

The NYISO's treatment is reasonable given the uncertainty about whether mitigated Prior-CY Projects will ever enter service. However, the NYISO's current treatment of exempted Prior-CY Projects could be improved by considering additional criteria for including them in the price forecasts. As discussed above, mitigated or exempted Prior-CY Projects may not necessarily proceed with the project as planned due to several uncertainties that are inherent in the development of new projects. Two circumstances where the developer of an exempted Prior-CY Project may delay or not move forward with the project include: (a) inability to secure permits or financing for the project, or (b) changes in the electric or gas market conditions which render the project uneconomic.

Although this issue did not affect the ultimate outcome of the CY17 BSM evaluations, the next Class Year could involve over 1.2 GW (Summer ICAP) of exempted Prior-CY Projects that may not have achieved commercial operation. Assuming that all such projects will be in service during the entire MSP might unreasonably depress the price forecast. Therefore, it would be beneficial for the NYISO to develop additional criteria for including such projects in its price forecasts.

4. Examined Facilities that Settled in CY17-1

As discussed in Section I.A.1, the NYISO provided final BSM determinations to four Examined Facilities in CY17-1. For its CY17-2 BSM evaluations, the NYISO's treatment of the Examined Facilities that settled in CY17-1 was similar to its treatment of Prior CY Facilities. Accordingly, the NYISO assumed all CY17-1 Projects to be in-service for its CY17-2 BSM evaluations. We find the NYISO's treatment of CY17-1 projects to be consistent with its Tariff.[95]

94 The specific criteria for including a mitigated Prior-CY Projects are described in the BSM CY15 Forecast Assumptions at Section 3.2.4.

95 See MST Section 23.4.5.7.3.2.

5. Examined Facilities Seeking Competitive Entry Exemption

As discussed in Section II, the NYISO considered requests from three Examined Facilities seeking a CEE ("CEE Projects") in its CY17 BSM evaluation. The NYISO's Tariff requires it to conduct the Part A and Part B tests modeling the potential entry of CEE Projects like other Examined Facilities. Accordingly, the NYISO estimated the UNC of the CY17 CEE projects based on the information provided by project developers. The NYISO subsequently incorporated the UNC of CEE Projects into its ICAP price forecast in a manner that is consistent with the test procedure described in Section VII.H. However, the Tariff-prescribed treatment for the CEE Projects could produce unreasonable outcomes for the BSM evaluations.

A developer's choice to move forward with a CEE Project will be driven by its own expectations, but the same information is not incorporated into the NYISO's estimated UNC. For instance, the developer of a CEE Project that would qualify for an exemption from the Offer Floor may commence construction, and expend a significant costs by the time the NYISO issues initial determinations. Similarly, it is possible for the developers of CEE Projects to have a view of the future market conditions that is significantly different from the NYISO's assumptions, particularly in areas where the NYISO's methodology could be enhanced.[96] In such situations, the UNC calculated in compliance with the tariff may not provide a reasonable representation of whether a CEE project would be in service during the MSP. Therefore, the NYISO's approach could result in unreasonably excluding CEE Projects in some situations.

Therefore, we recommend the NYISO develop Tariff provisions that would allow it to estimate the UNC based on a) any significant expenditures that the developer may have incurred by the Initial Decision Period, and b) well-substantiated developer forecasts.

6. Class Year 2017 Projects Located Outside the Mitigated Capacity Zones

The CY17 includes several projects that are located in Zones A-F and Zone K (Non-Mitigated Capacity Zones or "Non-MCZs"). Although the Tariff does not prescribe a specific treatment of the Non-MCZ projects, this issue could have a significant impact on BSM evaluations under the following circumstances:

- In case of excess supply in the G-J Locality and/ or Zone J, the ICAP prices in the MCZs could be determined based on the NYCA ICAP Demand Curve parameters.
- In the CY17 BSM evaluation, the Hydro Quebec region was capacity constrained during some of the winter months over the MSP. As a result, the CONE of the CHPE Project would depend on the NYCA ICAP prices as the developer may to procure capacity at NYCA prices to meet its capacity obligations in the Zone J.

96 See Table 1 for a summary of recommended enhancements to BSM evaluations.

Hence, the NYISO developed inclusion criterion for the Non-MCZ projects based on a two-part test:

- *Step 1* - If a Non-MCZ Project is already operational and/ or is only seeking CRIS rights, the NYISO assumed that the project is in-service for the purpose of the BSM evaluation.
- *Step 2* - For each Non-MCZ Project, examine whether it would earn sufficient capacity revenue to recoup its Unit Net CONE (estimated based on publicly available data sources) in the NYISO's capacity price forecast for MSP.[97] If a Non-MCZ Project earns sufficient capacity revenue under this test, it was included in the BSM ICAP Forecast.

For the CY17-1 BSM evaluation, over 1.2 GW of Non-MCZ Projects were included in the NYCA ICAP price forecast. In CY17-2 BSM evaluation, several Non-MCZ Projects were categorized as Existing Units in the ICAP forecast because they were included in the Existing Generation Facilities table in the latest Gold Book update. All other Non-MCZ Projects were not included as their estimated UNCs were higher than the forecasted ICAP prices in NYCA. We find the NYISO's treatment of the Non-MCZ Projects to be reasonable.

E. Impact of Imports on Capacity Price Forecast

The NYISO's assumptions regarding capacity imports from neighboring control areas are important since they impact the ICAP price forecast used in the BSM evaluations. This sub-section discusses the underlying assumptions for imports into the NYCA from PJM, ISO-NE, HQ and IESO across various transmission lines.

1. Imports from PJM to New York City

The BSM exemption tests require the NYISO to estimate the effects on capacity prices of controllable transmission lines that possess Unforced Capacity Deliverability Rights ("UDRs"). The assumptions regarding such facilities possessing UDRs are important, since there is currently 1 GW of potential capacity associated with UDRs between the PJM Interconnection ("PJM") and New York City. The evaluation of potential UDR capacity is complicated by two factors:

- Holders of rights to use UDRs must obtain capacity from the neighboring market in order to sell capacity into New York. They will not generally do this unless the New York City price is expected to be greater than the price in the neighboring market.
- If the holder of rights to use the UDRs elects by the annual deadline not to use its UDRs to import capacity to New York, the New York State Reliability Council's annual IRM technical study and Study Report will assume the line can provide emergency assistance. Consequently, the existence of the transmission line will tend to reduce the Locational

97 The NYISO estimated the UNC of renewable Non-MCZ Projects based on zonal cost and operational parameters from NREL's *2016 Annual Technology Baseline (ATB)*, available at: https://atb.nrel.gov/electricity/2016/summary.html. For non-renewable projects, the NYISO utilized cost information from permit proceedings or other publicly available sources.

Minimum Installed Capacity Requirements ("LCR") for New York City and the G-J Locality.

When conducting the MET for the CY17 Projects, the NYISO assumed that transmission lines possessing UDRs would import capacity to New York City when capacity could be sold at a price that would compensate the UDR rights holder for the cost of obtaining capacity and transmission service in the neighboring market.[98] This criterion was applied by Capability Year for the MSP since the PJM market runs annual rather than monthly auctions to satisfy installed capacity requirements. Overall, we find that the assumptions related to capacity imports that sink in New York City are reasonable and compliant with the NYISO Tariff.

2. Imports to Zones A-F and Zone K

The amount of net imports to and generation in NYCA Load Zones external to the G-J Locality can have a significant impact on the BSM exemption test for projects in the G-J Locality and New York City. This is because capacity prices in the G-J Locality and New York City are sometimes determined by the NYCA ICAP Demand Curve when there is substantial surplus capacity in either of those Localities. In general, capacity surpluses are forecasted to occur most during the Winter Capability Periods when the seasonal capability of most generators is highest. This subsection discusses assumptions made by the NYISO that affect the NYCA capacity price forecast.

Imports to Zone K

In recent years, there has not been a strong relationship between the capacity price spread between Long Island and neighboring ISOs, and the levels of capacity imports to Long Island across the Cross Sound Cable and the Neptune line (both of which have associated UDRs). Hence, the NYISO assumed that imports across the Cross Sound Cable and the Neptune line would remain at recently observed levels throughout the MSP.

Imports to Zones A-F

The NYCA's interfaces with neighboring Control Areas allow external resources from PJM, Hydro Quebec, ISO-NE and IESO to offer capacity into the NYCA region (*i.e.*, only the region outside of the G-J Locality, NYC, and Long Island). Capacity imports from neighboring control areas are limited by the NYISO-determined interface limits and Highway Deliverability Criteria.

98 The NYISO assumes that the cost of capacity in PJM's PSEG-North Local Delivery Area is equal to the clearing price in the Base Residual Auction in the closest year for which data is available.

Exports to neighboring areas may be limited by internal criteria or by criteria that is determined by the neighboring control area.[99]

PJM Interface – For the interface with PJM, the NYISO assumed that net imports would be limited by the NYISO-determined import rights limits. The net exports were limited to historically observed maximum levels over the past three years for the entire MSP for the PJM interface. Within these limits, the NYISO assumed that capacity would be imported from PJM when the NYCA capacity prices (adjusted for the cost of securing transmission service) are higher and exported to PJM when the NYCA capacity prices are lower.[100]

ISO-NE Interface – For the interface with ISO-NE, the NYISO followed a price differential-based approach as described in the context of UDRs (see Section VIII.C.1) for determining the direction of capacity imports.[101] The capacity price differential was adjusted for the cost of Pay for Performance ("PFP") obligations of capacity suppliers in ISO-NE. The limits on the magnitude of net imports or exports from ISO-NE were based on the results of the most recent ISO-NE capacity auctions.

HQ Interfaces – Although HQ exports large amounts of capacity to neighboring control areas, HQ has reliability criteria that limit the amount of capacity that is available for export to upstate New York and its other neighbors during some winter months. The NYISO used the following information to determine how much capacity would be exported from HQ to upstate New York during the months of December, January, February, and March:

- Historic average net imports to upstate New York for the month over the last three winters (i.e., 2015/16, 2016/17 and 2017/18 for CY17-1 BSM evaluation, and 2016/17, 2017/18 and 2018/19 for CY17-2 BSM evaluation);
- Plus forecasted increase in supply resources in HQ and imports from Ontario;[102]

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99 See Installed Capacity Manual Section 4.9.6 Maximum Allowances for Installed Capacity Provided by Resources Outside the NYCA (December 2016).

100 The cost of PJM capacity is based on an average of clearing prices for the MAAC Local Delivery Area. The NYISO assumed $86.04/MW-day for 2020/21, for 2021/22: $87.89/MW-day for CY17-1 BSM evaluation and $140/MW-day for CY17-2 BSM evaluation, and for 2022/23: $89.78/MW-day for CY17-1 BSM evaluation and $142.94/MW-day for CY17-2 BSM evaluation.

101 The cost of ISO-NE capacity is based on average clearing prices for ISO-NE Rest of System. The NYISO assumed $5.30/kW-month for 2020/21, $4.63/kW-month for 2021/22, and for 2022/23: $4.73/kW-month for CY17-1 BSM evaluation and $3.80/kW-month for CY17-2 BSM evaluation.

102 See *2017 and 2018 Long-Term Reliability Assessment by North American Electric Reliability Corporation*, available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_12132017_Final.pdf and https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

- Minus forecasted increase in capacity requirement for HQ because of load growth;[103]
- Minus forecasted exports to New York City across the CHPE transmission line.

In the other eight months of the year, net imports were assumed to be equal to the historic average net imports for those eight months during the three-year period from May 2015 to April 2018 for CY17-1 BSM evaluation, and May 2016 to April 2019 for CY17-2 BSM evaluation. This resulted in assuming approximately 1190 MW of net imports in the Summer Capability Period, November, and April, while the assumed net imports varied during the remaining months of the Winter Capability Periods of the MSP.

IESO Interfaces – The NYISO estimated the net imports from Ontario to be at a level that was observed over the most recent Capability Year of 2017/18 for CY17-1 BSM evaluation and 2018/19 for CY17-2 BSM evaluation. However, the imports from Ontario were not incorporated into the final ICAP forecast due to a spreadsheet error. This error had no impact on the outcome of the CY17 BSM evaluations.

Overall, we find that the assumptions related to imports sinking in Zones A – F and Zone K were reasonable and compliant with the NYISO Tariff.

F. Estimating Locational Capacity Requirements for the Mitigation Study Period

The NYISO determines the Locational Minimum Installed Capacity Requirements ("LCRs") every year for New York City, Long Island and the G-J Locality, which it uses in conjunction with the locational annual peak load forecast to calculate the locational ICAP requirements. The capacity price forecast used in the NYISO's BSM evaluation is significantly dependent on the LCRs assumed for the duration of the MSP. Hence, the assumed LCRs are important assumptions in the BSM evaluation.

The NYISO's current Tariff does not provide any guidance regarding the LCRs to be used in the BSM evaluations. As discussed in VII.D, the NYISO's assumptions underlying its capacity and energy forecasts included several changes to its resource mix. The LCRs during the MSP will be significantly influenced by the distribution of in-service capacity and by other system conditions which may differ from the current conditions.

LCR Assumptions for CY17-1 BSM Evaluation

For its CY17-1 BSM evaluation, the NYISO utilized the *Alternative Method for Determining LCRs* that the Commission approved in 2018.[104] The NYISO modeled the impacts of the following changes to the 2018 MARS RNA topology to estimate LCRs during the MSP:

103 See *2017 and 2018 Long-Term Reliability Assessment by North American Electric Reliability Corporation*.

104 The FERC Order is available at: https://www.ferc.gov/CalendarFiles/20181005163118-ER18-1743-001.pdf

- Retirement of Indian Point unit 2 in April 2020 and unit 3 in April 2021
- Increase the UPNY-ConEd interface transfer limit from 5750 MW to 6250 MW
- Updated load forecast for the MSP based on the most recent Gold Book data
- Addition of significant Non-MCZ Projects and the associated changes to the EFORd of generation in Zone C
- Addition of the CVEC Project for the MSP

The NYISO modeled the above changes except for the impact of the CVEC Project on the transmission security limits ("TSLs"). The assumed TSLs were 80 percent (for 2020/21) and 81 percent (for 2021/22 and 2022/23) for Zone J, and the TSLs for the G-J Locality were 90.5 (for 2020/21) and 91.5 percent (for 2021/22 and 2022/23).[105] Ultimately for the CY17-1 BSM evaluation, the NYISO estimated the LCRs during the MSP to be: (a) 83 percent during 2020/21 and 85 percent during 2021/22 and 2022/23 for Zone J, and (b) 91 percent during 2020/21 and 91.5 percent during 2021/22 and 2022/23 for the G-J Locality.

If the impact of the CVEC Project on transfer limits were incorporated into the evaluation, the TSL for the G-J Locality would have decreased by less than 2 percent, and could have resulted in a lower LCR. However, the impact of the CVEC Project was not fully quantified at the time of analysis and running the LCR Optimizer for multiple MARS topologies the purpose of the BSM evaluations would not be workable. Furthermore, as discussed in Section IV.A.3, this does not impact the determination of the CY17-1 Projects. Hence, we find the NYISO's approach for estimating the LCRs in the CY17-1 BSM evaluation to be reasonable.

LCR Assumptions for CY17-2 BSM Evaluation

For its CY17-2 BSM evaluation, the NYISO utilized the MARS topology used in 2017-1 BSM evaluation and updated it to reflect the changes in 2019/20 IRM study.[106] This updated MARS topology assumes that Con Edison's B3402 and C3403 345kV cables are out of service. In addition, the IRM decreased to 117 percent in 2019/20 from 118.2 percent in 2018/19.

To estimate the LCRs in the CY17-2 BSM evaluation, the NYISO modeled all the changes to its system that it modeled in CY17-1 BSM evaluation. The NYISO further increased the UPNY-ConEd interface transfer limit from 6250 MW to 6500 MW to reflect updates from Con Edison regarding the NYC 345kV series reactors.[107]

105 The current TSL levels are 80.16 percent for Zone J and 89.12 percent for the G-J Locality.

106 See *Differences in LCRs: CY2017-2 BSM & Public Policy AC Transmission Study*, dated May 30, 2019, available at: https://www.nyiso.com/documents/20142/3025517/Supplemental-LCR-information.pdf/e25b5075-ccd1-ccaa-9006-023a94709df5.

107 See *Buyer Side Mitigation ICAP Forecast – Class Year 17-2 ICAP Forecast Assumptions & References*.

The NYISO also updated the TSL for the G-J Locality to 89.5 percent for 202/21 and 90 percent for 2021/22 and 2022/23 in its CY17-2 BSM evaluation. The TSLs did not impact the estimated LCRs in the CY17-2 BSM evaluation.

Ultimately, for its CY17-2 BSM evaluation, the NYISO updated the estimated LCRs from CY17-1 BSM evaluation in the following manner:

- Decreased Zone J LCR to 84.5 percent (0.5 percentage point decrease) to account for two countervailing factors: (a) removal of the B3402 and C3403 cables, and (b) increase in the UPNY-ConEd transfer limit.
- Increased the G-J Locality LCR to 92.5 percent (1 to 1.5 percentage point increase), largely due to the decrease in IRM.

In addition to LCR estimates for the CY17 BSM evaluations, the NYISO developed an alternative set of LCRs that it used in the Public Policy AC Transmission study ("AC Transmission Study"). The NYISO documented the differences between the two studies in a recently published document. The NYISO attributed the differences to primarily two factors: (a) higher IRM in the AC Transmission Study, and (b) lower TSLs for the G-J Locality. The NYISO indicated that the higher IRM in the AC Transmission Study is a result of using the output of the LCR optimizer instead of the NYSRC-approved values from recent years. Furthermore, the AC Transmission Study included the impact of the CVEC Project on the TSL calculations whereas the CY17 BSM evaluation did not, resulting in a lower TSL in the former.

Overall, we find the NYISO's overall approach for estimating the LCRs in its CY17 BSM evaluations to be reasonable and compliant with the Tariff. We discuss the impact of key LCR sensitivities on the CY17 Part A and Part B evaluations in Sections III.A.3 and IV.A.3 respectively.

G. Treatment of Mitigated Projects in Capacity Forecast

The BSM exemption test requires the NYISO to estimate the effects on capacity prices of resources that have been determined to be subject to an Offer Floor. An Offer Floor is imposed on such resources until the resource clears for 12 months, which do not have to be consecutive.[108] The assumptions regarding such resources are important, since several projects in prior Class Years have been determined to not be exempt under the BSM rules. The treatment described below was applied to all MW of capacity that are subject to an Offer Floor and, including the mitigated units from Prior-CY Projects in accordance with subsection D.3.

108 The 12-month criterion is applied by the level of UCAP that cleared in the ICAP Spot Market Auction. Thus if a 100 MW resources clears 60 MW for six months and 100 MW for six months, 60 MW of the resource's cleared UCAP would not be mitigated and 40 MW would still be subject to the Offer Floor. See *BSM Numerical Example,* Section 6.4.

The NYISO considered how the Offer Floor of a mitigated unit would evolve over time in the capacity price forecasts. This required the NYISO to forecast capacity prices not only during the MSP, but also for the months leading up to the MSP. Accordingly, if MW of capacity subject to an Offer Floor was expected to clear in a month prior to the MSP or during the initial portion of the MSP, those sales would be considered in the NYISO's assumptions regarding how much of the unit's capacity would be subject to the Offer Floor in subsequent months of the MSP. The price level of each Offer Floor was adjusted annually for inflation, using the 2.15 percent inflation rate underlying the currently-effective ICAP Demand Curves. We find that NYISO's methodology in this regard was reasonable and compliant with the NYISO Tariff.

H. Testing Multiple Examined Facilities

MST §23.4.5.7.3.2 states that "when the ISO is evaluating more than one Examined Facility concurrently, the ISO shall recognize in its computation of the anticipated ICAP Spot Market Auction forecast price that Generators or UDR facilities will clear from lowest to highest, using for each Examined Facility the lower of (i) its Unit Net CONE or (ii) the numerical value equal to 75% of the Mitigation Net CONE". This provision is designed to ensure that the test identifies the most economic Examined Facility when some but not all of the Examined Facilities in the Class Year are economic.

In the CY17 BSM evaluation, the NYISO continued to apply MST §23.4.5.7.3.2 to the Part A and Part B tests using a modified procedure that it used in CY15.[109] Specifically, the NYISO first tested the Examined Facility with the lowest presumptive Offer Floor by itself in the Part A and Part B tests assuming it offers as a price taker. If the first Examined Facility received an exemption, it was included in the test for subsequent Examined Facilities. If the first Examined Facility did not receive an exemption, then it was excluded from the ICAP forecast for the subsequent Examined Facilities in the sequence.

CY17 bifurcated as a result of the Linden Uprate Project and the Linden Addition CRIS MW Project opting to pursue additional SDU studies. For the CY17-1 evaluations, the NYISO estimated the UNC for both the Linden projects and treated them in a manner consistent with the above procedure. For the CY17-2 BSM evaluation, all the CY17-1 Projects were assumed to be in service (see subsection D.4). Hence, only the three CY17-2 Projects were tested according to the modified procedure.

We find the NYISO's test procedure to be compliant with the Tariff and support its continued use for future BSM evaluations.

109 See *BSM Numerical Example*, Section 6.1 and Section 6.2.

VIII. Conclusions and Recommendations

In CY17-1 BSM evaluation, the NYISO issued final determinations for two projects for an exemption under the Part A and Part B tests, and two projects for a CEE.[110] The CY17 Berrians Project and the East River 6 Project were determined to be exempt under the Part B test, while the BEC II Project and the CVEC Project were deemed to be exempt under the CEE provisions. We reviewed materials documenting the NYISO's evaluation of investment costs, the reasonably anticipated LBMPs and net revenues, and capacity price forecasts for all the CY17 Examined Facilities. We also reviewed the materials regarding three Examined Facilities' requests for a CEE.

Ultimately, the retirement of Indian Point was the key driver of the exemptions under the Part B test. The retirement of Indian Point capacity led to a very low capacity margin in the G-J Locality, and increases in the Zone J capacity and energy prices over the MSP. This factor in conjunction with the generally lower costs (compared to a new build) resulted in the CY17 Berrians Project and the East River 6 Projects being exempt from the Offer Floor in the CY17-1 BSM evaluations.

In CY17-2 BSM evaluation, the NYISO conducted BSM evaluations and confidentially provided initial determinations for three Examined Facilities. However, none of the CY17-2 Projects received a final determination as all three projects rejected their respective PCA for SDUs and Deliverable MW.

We conclude that the NYISO's BSM determinations in both settlement phases of CY17 were made in accordance with the requirements of the Tariff and based on reasonable assumptions.

We identify five issues with the Tariff that, if addressed, could improve the accuracy of the capacity price forecasts and the Unit Net CONE, and/ or would strengthen the provisions of the CEE. We also identify three improvements to the BSM evaluation assumptions that do not require tariff modifications. We find that if the Starting Capability Year issue had been addressed before the CY17 evaluation, it is possible that it would have changed the outcome of the Part A test for a subset of the Examined Facilities. A number of other issues may have significant impacts on the results of future BSM evaluations. Accordingly, we recommend that the NYISO address these issues in future evaluations.

The following table summarizes the issues for which we identified a potential improvement (indicated by an "I" in the last column) in an assumption or an issue with the test that could be

110 The NYISO confidentially provided an initial determination to the CHPE Project as part of CY17-1. The project elected to proceed to CY17-2 and did not receive a final determination in CY17-1.

addressed by a tariff change (indicated by a "T" in the last column). The second column indicates where each issue is discussed in this report.

Table 1: Summary of Recommended Enhancements to BSM Evaluation

Issue	Section	Rec
Interconnection costs may be inflated for some Examined Facilities (Part B test)	VI.A.4	T
Starting Capability Period is unrealistic for most Examined Facilities (Part A & B tests)	VII.A	T
Treatment of some Existing Units at risk of retiring or mothballing is unrealistic for some units (Part A & B tests)	VII.D.2	T
Treatment of Examined Facilities seeking Competitive Entry Exemption may be inconsistent with developers' expectations (Part A & B tests)	VII.D.5	T
Treatment of exempt Prior Class Year Projects in the Interconnection Queue may be unrealistic (Part A & B tests)	VII.D.3	I
Modify Part A test procedure to exempt Zone J projects if they are needed to satisfy the G-J Locality's capacity requirement (Part A test)	III.B	T