ASSESSMENT OF THE BUYER-SIDE MITIGATION EXEMPTION TESTS FOR THE CLASS YEAR 2012 PROJECTS

by:

NYISO Market Monitoring Unit

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I. EXECUTIVE SUMMARY

The NYISO's tariff requires that the Market Monitoring Unit prepare a report to be posted concurrently with the results of any buyer-side mitigation ("BSM") determinations. This report provides our review of the BSM determinations for the following Class Year 2012 ("CY12") Examined Facilities:

- The Berrians GT III Project ("CY12 Berrians Project") – The latest of the proposed additions to NRG's larger multi-phase Berrians project. The CY12 Berrians Project is a single 1 x 1 x 1 combined cycle unit with a nominal capacity of 250 MW.
- The Champlain Hudson Power Express ("CHPE") Project – A proposed 333-mile 1,000 MW High Voltage Direct Current ("HVDC") merchant transmission line running from the US-Canada border to New York City. The CHPE Project is being developed by Transmission Developers Inc. ("TDI").
- The Cricket Valley Energy Center ("CVEC") Project – A proposed natural gas-fired combined-cycle plant with three units, each having a 1 x 1 x 1 configuration with a total nominal capacity of 950 MW. This project is being developed by Cricket Valley Energy Center, LLC ("Cricket Valley").

The BSM measures are designed to deter uneconomic entry by imposing an Offer Floor on uneconomic new resources. The BSM evaluation consists of two parts. 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, which is 75 percent of the net CONE of the hypothetical unit modeled in the most recent Demand Curve reset.[1] An Examined Facility passes the Part A test if the price forecast for the first year is higher than the Default Net CONE. 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.

The Part B test compares a forecast of capacity prices in the first three years of an Examined Facility's operation to the net CONE of the Examined Facility ("Unit Net CONE"). An

1 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.

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"), and if not defined therein, then in Open Access Transmission Tariff Attachment S.

Examined Facility passes the Part B test if the price forecast for the three years is higher than the Unit Net CONE of the Examined Facility. The purpose of the Part B test is to ensure that a resource is not mitigated when it would be economic to enter the market. An Examined Facility is exempted from Offer Floor mitigation if it passes either the Part A test or the Part B test.

The NYISO's BSM evaluations are coordinated with its Class Year Project Cost Allocation ("PCA") process. The PCA process requires the developers to accept their PCA, headroom payment, and Deliverable MW in order to receive CRIS rights. In each round of the PCA process, the NYISO provides each Examined Facility that remains in the Class Year, with its estimated PCA and its BSM determination results, so each developer can consider this information before deciding whether to accept the PCA. A new Class Year round is conducted if one or more projects reject the PCA because this can affect the PCA amount for other projects in the Class Year. If a project drops out of the Class Year or rejects its PCA, it can affect the ICAP and Energy and Ancillary Services forecasts, which are inputs to the BSM determinations for other Examined Facilities. Hence, the BSM evaluation process requires an updated determination for each Examined Facility in each round that it remains until the completion of the Class Year.

The remainder of this section provides a summary of key conclusions from our review. Sections II to VII provide a detailed review of the NYISO's assumptions. Section VIII of this report provides a summary of our conclusions and a list of issues that we recommend be addressed in future BSM evaluations.

CY12 Initial Decision Round

The NYISO evaluated the three CY12 Examined Facilities and confidentially provided a BSM determination to each developer prior to the Initial Project Cost Allocation.[2] We reviewed information submitted by the developers and the assumptions supporting the determinations. We

[2] The BSM determination results for the Initial Decision Round are not published, but this report discusses the assumptions.

find that the results of the Part A and Part B test in the Initial Decision Round were in accordance with the requirements of the Tariff. The CHPE Project and CVEC Project each rejected its Project Cost Allocation and dropped out of CY12. Therefore, at the end of the Initial Decision Round, the CY12 Berrians Project was the only Examined Facility remaining in CY12.

CY12 Final Decision Round – Part A Test Results

The NYISO forecasted UCAP prices for Zone J of $88.83/kW-year in the Part A test for the Final Decision Round, which was lower than the Default Net CONE of $122.33/kW-year UCAP for the same period, so the CY12 Berrians Project did not pass the Part A test.

The key driver of the Part A test result was that the NYISO forecasted capacity sales would exceed the requirement for Zone J by approximately 8 percent (following the entry of the CY12 Berrians Project), while the CY12 Berrians Project would not pass the Part A test unless the forecasted capacity margin was less than 5.35 percent of the requirement.[3]

We find that the capacity price forecast was depressed by assumptions about the Starting Capability Period of the CY12 Berrians Project (Summer 2015) and mothballed capacity in Zone J. These assumptions were made according to the requirements of the NYISO tariff, but they result in an unrealistically high forecast of the capacity sales margin.[4] We find that the outcome of the Part A test may have been different for the CY12 Berrians Project if more realistic assumptions had been used in these two elements of the test. Hence, it is important to modify the Tariff to allow for more reasonable assumptions in future BSM evaluations.

Overall, we find that the assumptions used in the Part A test for the Final Decision Round were in accordance with the NYISO's tariff.

[3] These capacity margins are based on the Summer Capability Period. Winter Capability Periods have higher capacity margins because most thermal generators are credited with higher capabilities during colder temperatures.

[4] These assumptions are discussed further in Sub-Sections III.B.1 and III.B.2. Their effect on the Part A test is discussed further in Sub-section III.B.3.

CY12 Final Decision Round – Part B Test Results

The NYISO forecasted UCAP prices for Zone J of $124.06/kW-year in the Part B test of the Final Decision Round, which was lower than the Examined Facility's Unit Net CONE, so the CY12 Berrians Project did not pass the Part B test. The Unit Net CONE for the CY12 Berrians Project was calculated by the NYISO after evaluating information submitted by the developer.

A key driver of the Part B test result was that the NYISO forecasted transmission constraints on exports from the Astoria Annex (where the CY12 Berrians Project would interconnect), which would reduce the forecasted net revenue earned by the project very significantly. The CY12 Berrians Project likely would have received an exemption if these transmission constraints were not reflected in the NYISO's net revenue model. It was appropriate for the NYISO to reflect this congestion in its net revenue estimates, since the congestion would diminish the net revenues that would be earned by a competitive supplier selling at the Astoria Annex.[5]

Overall, we find that the results of the Part B test for the Final Decision Round were in accordance with the NYISO's tariff. Since the CY12 Berrians Project did not pass the Part A or Part B tests, it will be subject to an Offer Floor.

5 Although the ratings of the lines exiting the Astoria Annex are sufficient for the CY12 Berrians Project to receive 250 MW of Deliverable MW for the purpose of selling capacity, the ratings do cause frequent congestion in the NYISO's forecast of net revenues from energy sales. Prior to 2010, an operating exception had allowed these lines to be operated to higher ratings, but no operating exception currently exists that would allow the use of higher ratings. Accordingly, the NYISO's evaluation assumed no operating exception. Additional details about this issue are provided in Sub-sections IV.B and VI.F.

II. Introduction and Summary

The NYISO's Market Administration and Control Area Services Tariff ("MST", or the "Tariff") requires that the Market Monitoring Unit ("MMU") prepare a report to be posted concurrently with the results of buyer-side mitigation ("BSM") determinations.[6] The NYISO has conducted the Part A and Part B tests of the BSM determinations for three Class Year 2012 ("CY12") Examined Facilities.[7,8] This report provides our review of the BSM determinations, and it has been posted concurrently with the final BSM determination result for the Berrians GT III Project.[9] We concur with the NYISO's BSM determinations for CY12.

Three CY12 Examined Facilities received an initial BSM determination in the Initial Decision Round of the Class Year Project Cost Allocation. After two Examined Facilities dropped out of

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6 See *Astoria Generating Company, L.P., et al. v. New York Independent System Operator, Inc.*, 139 FERC ¶ 61,244 (2012) at PP 130:

> [Regarding the request for] a written report by NYISO's MMU confirming whether NYISO's mitigation and exemption determinations and calculations were conducted in accordance with the terms of the Services Tariff, and, if not, identifying the flaws inherent in NYISO's approach, we direct the MMU to prepare a public report discussing its assessment of the buyer-side mitigation determinations.

Also see MST §23.4.5.7.7.

7 The Part A and Part B tests are set forth in MST §23.4.5.7.2. Details on the NYISO's general application of these tests are provided in the *BUYER SIDE MITIGATION NARRATIVE AND NUMERICAL EXAMPLE* ("BSM Numerical Example") (March 7, 2014, available at: http://www.nyiso.com/public/webdocs/markets_operations/services/market_monitoring/ICAP_Market_Mitigation/Buyer_Side_Mitigation/Numerical_Example/BSM_Narrative_and_Numerical_Example%20March%207%202014.pdf.

Details on the capacity price forecast assumptions used for CY12 Examined Projects are provided in *BUYER SIDE MITIGATION ICAP FORECAST – ASSUMPTIONS AND REFERENCES FOR CLASS YEAR 2012 EXAMINED PROJECTS* ("BSM CY12 Forecast Assumptions"), dated November 12, 2014, and revised for the second decisional round dated December 26, 2014; available at: "http://www.nyiso.com/public/markets_operations/services/market_monitoring/index.jsp".

8 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").

9 The NYISO's determination is available on the NYISO's website with Class Year 2012 information at: "http://www.nyiso.com/public/markets_operations/services/market_monitoring/index.jsp.".

CY12, the remaining project (which was the Berrians GT III Project) received a BSM determination prior to the Final Decision Period.[10]

The Berrians GT III Project accepted its System Upgrade Facilities ("SUF") project cost allocation, head room payment, and its Deliverable MW. It did not receive a BSM exemption, so the NYISO has calculated its Offer Floor as the lower of: (a) the Unit Net CONE of the project and (b) the Default Net CONE, which is 75 percent of the Mitigation Net CONE.[11]

A. CY12 EXAMINED FACILITIES

Berrians GT III Project ("CY12 Berrians Project")

The CY12 Berrians Project is a single 1 x 1 x 1 combined cycle unit with a nominal capacity of 250 MW.[12] This is the latest of the proposed additions to NRG's larger Berrians project, which is permitted for a natural gas-fired combined cycle plant with four 250 MW units with a total nominal capacity of 1,000 MW.[13] The larger Berrians project is located in Queens, New York, and the proposed CY12 Berrians Project will be connected to the grid at Con Edison's 345-kV

10 The NYISO revised the CY12 Berrians Project's Unit Net CONE value issued at the time of the December 29, 2014 Class Year 2012 Second Round Project Cost Allocations, to reflect the NYISO's January 6, 2015 revision to the Project Cost Allocation ("PCA"). The January 6, 2015 PCA revision is described in the CY12 update available at: "http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Interconnection_Studies/Notices_to_Market_Participants/Notice%20of%20Class%20Year%202012%202nd%20Round%20Cost%20Allocation_Update%2001-06-2015.pdf". In this report, references to the BSM determination provided prior to the Final Decision Period refer to the final revised Unit Net CONE.

11 "Mitigation Net CONE" as used in this report has the same definition as the NYISO's August 24, 2010 compliance filing in accordance with the Commission's Order: *New York Independent System Operator, Inc.*, 131 FERC ¶ 61,070 (2010). MST Section §23.2 defines "Mitigation Net CONE" as "the capacity price on the currently effective ICAP Demand Curve for the Mitigated Capacity Zone corresponding to the average amount of excess capacity above the Mitigated Capacity Zone Installed Capacity requirement, expressed as a percentage of that requirement, that formed the basis for the ICAP Demand Curve approved by the Commission."

12 *See Class Year 2012 Facilities Studies System Upgrade Facilities (SUF)*, a report from the New York Independent System Operator; and Second Round Addendum to that report.

13 The first of the four units ("CY11 Berrians Project") was evaluated as part of the Class Year 2011 BSM evaluation. The NYISO determined that CY11 Berrians Project was not exempt from the Offer Floor, although the developer accepted its CY11 interconnection cost allocation.

Astoria Annex GIS substation. The developer accepted its CY12 SUF project cost allocation and headroom payment. The NYISO has determined that the CY12 Berrians Project is not exempt under the Part A test or the Part B test.

Champlain Hudson Power Express ("CHPE") Project

The CHPE Project is a proposed 333-mile 1,000 MW High Voltage Direct Current ("HVDC") merchant transmission line running from the US-Canada border to New York City. The proposed line includes two 345 kV cables with submarine portions totaling 196 miles and upland portions totaling 137 miles. A converter station would be built at the Astoria Generating Complex in Astoria, Queens and would connect to the NYISO system at the Astoria Annex GIS substation. The project is under development by the Transmission Developers Inc. ("TDI"). The NYISO provided the results of an initial BSM determination to TDI before the Initial Decision Period for the CHPE Project. TDI elected to remove the CHPE Project from CY12, so it did not receive a final BSM determination. TDI retains the ability to enter the CHPE Project in one of the next two Class Years.

Cricket Valley Energy Center ("CVEC") Project

The CVEC Project was 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 950 MW. This project was under development by Cricket Valley Energy Center, LLC ("Cricket Valley"). The NYISO provided the results of the BSM determination to Cricket Valley prior to the Initial Decision Period, and Cricket Valley elected to remove the CVEC Project from CY12, so it did not receive a final BSM determination. This CVEC Project (NYISO interconnection queue position #310) is not eligible to reenter the next Class Year, but another Cricket Valley project (interconnection queue position #444) may be eligible to do so.

B. SUMMARY OF BSM REPORT FOR CY 12 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 for the three CY12 Examined Facilities. 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 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.

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.[14] 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.

Initial Decision Round - The forecasted UCAP prices for the first year of the MSP were lower than the Default Net CONE of $122.33/kW-year UCAP for Zone J and $83.59/kW-year UCAP for the G-J Locality, so none of the CY12 Projects passed the Part A test for the Initial Decision Round. Sub-section III.A evaluates the assumptions used to forecast capacity prices and to compare the capacity prices with the Default Net CONE for the Initial Decision Round.

Final Decision Round - The forecasted UCAP price for Zone J was $88.83/kW-year in the Part A test for the Final Decision Round. The forecasted UCAP price was lower than the Default Net CONE of $122.33/kW-year UCAP for the first year of the MSP, so the CY12 Berrians Project did not pass the Part A test for the Final Decision Round. Sub-section III.B evaluates the assumptions used to forecast capacity prices and to compare the capacity prices with the Default Net CONE in the Final Decision Round.

A. Initial Decision Round

Three Examined Facilities were tested jointly in the Initial Decision Round. The test was generally performed using reasonable assumptions that were in accordance with the NYISO MST. However, we identify a procedural concern (which is described below) that should be addressed in future BSM determinations. Ultimately, we find that this issue did not affect the outcome of the Part A test in the Initial Decision Round.

Test Procedure for Multiple Examined Facilities

The NYISO conducted the Part A test for the three CY12 Projects in the Initial Decision Round. The Tariff states that "when the ISO is evaluating more than one Examined Facility

14 See *BSM Numerical Example*, Section 2.

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". However, all three CY12 Projects were assumed to offer as price takers (i.e., at $0) for the purposes of the Part A test, resulting in the same UCAP price forecast and the same outcome for all three Examined Facilities. This procedure could result in mitigating all of the Examined Facilities even in case of a local capacity deficiency.[15,16]

Hence, we recommend the NYISO modify its methodology for the Part A test for future BSM evaluations to address this concern. One possible way to improve the Part A test procedure would be to recognize that the Examined Facilities would clear from lowest to highest based on their presumptive Offer Floors.[17]

B. FINAL DECISION ROUND

The CY12 Berrians Project was tested in the Final Decision Round. The test was performed using reasonable assumptions that were in accordance with the NYISO MST. This sub-section discusses how several key factors affected the outcome of the Part A test of the CY12 Berrians Project for the Final Decision Round. Section VII discusses other assumptions that were used in the Part A test.

1. Starting Capability Period of Summer 2015

The Starting Capability Period is important because the assumed timing of entry affects the load forecast and other assumptions that are used in the capacity price forecast and the Default Net

15 The purpose of the Part A test is to ensure that an Examined Facility receives an exemption when its capacity is needed to avoid a capacity deficiency.

16 Additional details are provided in Sub-section VII.G about the procedure for testing multiple Examined Facilities.

17 This concept is discuss further in Sub-section VII.G.

CONE.[18] In compliance with the Tariff, the CY12 Berrians Project was assumed to enter in Summer 2015, although a more reasonable assumption for the CY12 Berrians Project's entry date would be 2016 at the earliest. If the Starting Capability Period was pushed back to Summer 2016 for the purposes of the final determination, an additional 1.4 percent (165 MW) of anticipated load growth and 2.2 percent escalation in the assumed ICAP Demand Curve would increase the price forecast by up to $23/kW-year UCAP.[19] Using a more realistic Starting Capability Period would not by itself have enabled the CY12 Berrians Project to pass the Part A test.

2. Treatment of Mothballed Units and Units Transferring CRIS Rights

The NYISO forecasted capacity prices using the following assumptions as required by the Tariff:[20]

- 421.4 MW of mothballed capacity would be offered as price-takers (i.e., at $0) in New York City even though the majority of this capacity will not likely return to service;
- Approximately 100 MW of New York City capacity that is anticipated to transfer its CRIS rights to another Berrians project ("Berrians I/II" or "CY11 Berrians Project") would continue selling capacity even if the CY11 Berrians Project becomes operational.

Excluding all of the mothballed capacity could raise the capacity price forecast for Zone J by up to $56/kW-year UCAP in the Final Decision Round.[21,22] Although it may be reasonable to assume that some amount of mothballed capacity would return under certain circumstances,

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

19 However, this increase would be offset partly by higher forecasted sales from UDR projects and/or resources subject to an Offer Floor. This is because a higher capacity price might induce a UDR project to import additional capacity from an external control area. Likewise, a higher capacity price might allow additional capacity sales from a resource subject to an Offer Floor.

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

21 Some units that are anticipated to transfer CRIS rights are also mothballed, so this would reduce the joint impact of resolving these two issues.

22 However, this increase would be offset partly by higher forecasted sales from UDR projects and/or resources subject to an Offer Floor.

assuming that all mothballed capacity will sell substantially reduced the forecasted capacity prices and could have influenced the outcome of the Part A test. This underscores the importance of modifying the Tariff to implement more reasonable assumptions in future BSM determinations.

3. Conclusions

If the assumptions discussed in Parts 1 and 2 of this sub-section were modified, it would tend to increase the capacity price forecast. The net result of these modifications would be partly offset by increased sales from UDR projects and generators to the extent allowed by the Offer Floor imposed on the resource. Overall, we find that if these issues could have been addressed, it likely would have altered the price forecast and, thus, could have affected whether the CY12 Berrians Project received an exemption in the Final Decision Round. Hence, we recommend the NYISO modify the Tariff to allow more reasonable assumptions in future BSM determinations.

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.[23] 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.[24]

Initial Decision Round - The NYISO forecasted UCAP prices and compared them to the Unit Net CONE for each Examined Facility. The forecasted UCAP prices were $120.05/kW-year for Zone J and $35.85/kW-year for the G-J Locality.[25] Sub-section IV.A evaluates the assumptions used to forecast capacity prices and to perform the BSM determination for each Examined Facility.

Final Decision Round - The NYISO forecasted UCAP prices of $124.06/kW-year for Zone J in the Part B test, which were lower than the Unit Net CONE of the CY12 Berrians Project, so the CY12 Berrians Project did not pass the Part B test.[26] Sub-section IV.B evaluates the assumptions used to forecast capacity prices and the overall result of the Part B test of the Final Decision Round.

[23] See *BSM Numerical Example*, Section 3.

[24] 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.

[25] The Part B test outcomes are not provided in this report for the Initial Decision Round because the Commission has only directed the NYISO to publish the results of final BSM determinations. See Astoria Generating Company, L.P., et al. v. New York Independent System Operator, Inc., 139 FERC ¶61,244 (2012) at PP 23. It states “[W]e will direct NYISO to… require the disclosure of the identity of the project and the final exempt/non-exempt determination, as soon as they are final.”

[26] The Unit Net CONE is not provided in this report because it is confidential.

A. Initial Decision Round

We find that the Part B test for the Initial Decision Round was performed using assumptions that were in accordance with the NYISO MST. Many of the NYISO's assumptions are discussed in detail in Sections V, VI, and VII of this report. In particular, Section VII.G discusses one aspect of the NYISO's Part B test procedure that is not inconsistent with the Tariff but that we recommend modifying in future BSM evaluations to be more consistent with the purpose of the Part B test. This is because the current procedure could lead an uneconomic project to pass the Part B test under certain circumstances. Ultimately, this issue did not affect the results of the Part B test in the Initial Decision Round.

B. Final Decision Round

The CY12 Berrians Project was tested in the Final Decision Round. The test was performed using reasonable assumptions that were in accordance with the NYISO MST.[27] This sub-section discusses how several key factors identified in other sections of this report affected the outcome of the Part B test of the CY12 Berrians Project in the Final Decision Round. Sections V, VI, and VII discuss in detail other assumptions that were used in the Part B test.

1. Starting Capability Period of Summer 2015

The Starting Capability Period is important because the assumed timing of entry affects the load forecast and other assumptions that are used in the capacity price forecast and the net revenue forecast, which is an input to the Unit Net CONE.[28] Under the current Tariff, the CY12 Berrians Project is assumed to enter in Summer 2015. If the Starting Capability Period were pushed back to Summer 2016, an additional 1.4 percent (165 MW) of anticipated load growth and 2.2 percent escalation in the assumed ICAP Demand Curve could increase the price forecast for Zone J by

27 As discussed in Sub-section VII.H, the NYISO assumed that the CY12 Berrians Project will offer its capacity into the ICAP market at its presumptive Offer Floor rather than as a price taker. Although we recommend modifications to this assumption, it did not impact the Part B test result in the Final Decision Round.

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

up to $24/kW-year UCAP.[29] Using a more realistic Starting Capability Period would not by itself enable the CY12 Berrians Project to pass the Part B test.

2. Treatment of Mothballed Units and Units Transferring CRIS Rights

The NYISO forecasted capacity prices and LBMPs using the following assumptions as required by the Tariff:[30]

- 421.4 MW of mothballed capacity would be offered as price-takers in New York City even though this capacity would not likely to return to service;
- Approximately 100 MW of New York City capacity that is anticipated to transfer its CRIS rights to another Berrians project ("Berrians I/II" or "the CY11 Berrians Project) would continue selling capacity even if the CY11 Berrians Project becomes operational.

Excluding all of the mothballed capacity could raise the capacity price forecast for Zone J by up to $57/kW-year UCAP.[31,32] However, it may be reasonable to assume that some amount of mothballed capacity would return under certain circumstances. This underscores the importance of modifying the Tariff to implement more reasonable assumptions in future BSM determinations.

3. Astoria Annex Delivery Constraints

The NYISO accounted for the congestion of power being exported from the Astoria Annex by adjusting the LBMP forecast and the forecasted production of the CY12 Berrians Project. These transmission constraints reduced the forecasted LBMPs by 10 percent and reduced the forecasted production and net revenue of the CY12 Berrians Project. Hence, these transmission constraints had a very significant impact on the CY12 Berrians Project's Unit Net CONE. Furthermore, we

29 This increase would be offset partly by higher forecasted sales from UDR projects and/or resources subject to an Offer Floor.

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

31 Some units that are anticipated to transfer CRIS rights are also mothballed, so this would reduce the joint impact of resolving these two issues.

32 This increase would be offset partly by higher forecasted sales from UDR projects and/or resources subject to an Offer Floor.

find that if these transmission constraints had not been considered in the BSM evaluation, the CY12 Berrians Project would likely have passed the Part B test for the Final Decision Round.[33] We find that the NYISO's approach to modeling these constraints was appropriate.[34]

4. Conclusions

Ultimately, the transmission constraints limiting exports from the Astoria Annex were the primary driver of the final outcome of the Part B test for the CY12 Berrians Project (as discussed in Sub-section B.3). The NYISO appropriately reflected the constraints and associated congestion in its net revenue estimate.

We identify two issues (in Sub-sections B.1 and B.2) with the Tariff related to the assumed Starting Capability Period and treatment of mothballed units that, if addressed, would substantially improve the accuracy of the capacity price forecast. Although we find that the two issues did not affect the determination that the CY12 Berrians Project is not exempt under the Part B test, they materially affect the forecasted capacity prices and could therefore affect the Part B tests in future BSM evaluations. Therefore, we recommend the NYISO modify the MST to allow more reasonable assumptions regarding the treatment of mothballed units in the capacity price forecast and the Starting Capability Period for the Examined Facilities in future BSM determinations.

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33 As discussed in Sub-section VII.H, the NYISO assumed that the CY12 Berrians Project will offer its capacity into the ICAP market at its presumptive Offer Floor rather than as a price taker. It is unclear whether this assumption would have affected the Part B test result in the Final Decision Round under the hypothetical scenario where exports from the Astoria Annex were not constrained.

34 These constraints are discussed in detail in Sub-sections VI.C.3, VI.D.4, and VI.F.

V. Part B Test Input – Cost of New Entry

The BSM exemption test requires the NYISO to estimate the annual levelized cost of new entry ("CONE") of an Examined Facility, since its CONE is used as an input to the Part B test. The developers of the CY12 Projects provided cost information that was evaluated by the NYISO with the assistance of Sargent & Lundy. The evaluation included requests for additional information as well as comparisons with cost data developed independently by Sargent & Lundy. The NYISO made a number of key determinations regarding how the cost information should be reflected in the estimated CONE of the projects. This section evaluates several important assumptions that were used in the NYISO's CONE estimates.

A. Assumptions Affecting CONE of Multiple CY12 Projects

This section discusses the general principles and methods used to estimate components of CONE for all the CY12 Projects.

1. Cost of Capital

The NYISO and its consultants considered the cost of capital estimates submitted by the CY12 Projects' developers and sought to use the submitted values in cases where the submittal was well substantiated. If unsubstantiated, the NYISO developed estimates for the project-specific weighted average cost of capital ("WACC") using the Capital Asset Pricing Model ("CAPM") in a manner consistent with the Demand Curve reset. The estimates used CAPM inputs that were updated to reflect changes in the prevailing market conditions since the last Demand Curve reset. 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 used proxy values from the Demand Curve reset.

2. Interest During Construction

The NYISO estimated the Interest During Construction ("IDC") for each of the Examined Facilities using the adjusted pre-tax WACC that was derived based on the principles outlined in Part 1 of this sub-section. The adjusted discount rate was applied to the project-specific construction draw schedule to determine the IDC component of the CONE.

3. Contingency

The NYISO, in consultation with Sargent & Lundy, assumed a contingency cost based on the level of certainty of cost data submitted by the CY12 Projects' developers. In some cases, the NYISO used a value for the contingency that was different from the value used for the Demand Curve Reset. Some of the factors that contribute to uncertainty are: (a) the developers do not have a signed EPC contract for constructing the Examined Facility, (b) the Examined Facility is in a preliminary stage of development and/or, (c) the technology and/or circumstances of the Examined Facility are novel or relatively untested.

4. Useful Life and Residual Value

The NYISO and its consultants evaluated the applicability of proxy parameters from the Demand Curve reset for the useful life and residual value for each of the CY12 Examined Facilities. Two of the CY12 Projects use combined cycle technology, which can reasonably be expected to have a longer useful life and/or a higher residual value when compared to the Demand Curve unit.[35] Furthermore, both combined cycle projects would be located at large generating stations, which tends to reduce operating costs of individual generators at the station. These attributes provide a basis for assuming a longer useful life and/or higher residual value for the combined cycle-based CY12 Projects than for the smaller combined cycle plant that was studied in the Demand Curve reset.[36] Similarly, the NYISO assumed a longer useful life for the CHPE Project than the Demand Curve unit, consistent with previous BSM determinations, since the NYISO and its consultants have determined that an HVDC transmission line is likely to remain in service for a longer period than a peaking generator.

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[35] Sections IV.C and IV.D of August 2013 NERA report "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator" discuss the use of these parameters.

[36] In the demand curve reset study, a 25-yr/5% assumption was used for the combined cycle plant.

5. Interconnection Costs

Consistent with Commission directives in previous BSM evaluations, the NYISO used the Project Cost Allocations for System Upgrade Facilities ("SUFs") and System Deliverability Upgrades ("SDUs") and the headroom payments from the CY12 Facilities Studies Reports to estimate the interconnection costs of the Examined Facilities.[37] For the Initial Decision Round, the Project Cost Allocations and headroom payments were approximately $9.5 million for the CY12 Berrians Project, $150 million for the CHPE Project, and $297 million for the Cricket Valley Project, making them a major component of the estimated CONE for some Examined Facilities. For the Final Decision Round, the CY12 Berrians Project's Project Cost Allocations and headroom payments rose to approximately $11.8 million.

The NYISO is responsible for developing the Project Cost Allocations, so cost estimates were developed for each Examined Facility by the Connecting or Affected Transmission Owners ("TO") and the NYISO with input from the developer. In some cases, developers have submitted their own interconnection cost estimates that were significantly lower than the project cost allocations.

The Project Cost Allocation is the amount of financial Security that a developer must post in order to remain in the Class Year. If the actual cost of constructing the SUFs and/or SDUs is lower than the amount of Security, the developer is only responsible for the actual cost incurred.[38] The purpose of the Project Cost Allocation is to ensure that the developer takes financial responsibility for estimated interconnection costs that are developed by the NYISO, 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. Hence, we recommend that the NYISO consider whether to modify its tariff to allow the BSM evaluation to develop interconnection cost estimates.

[37] See MST §23.4.5.7.3.3.

[38] See OATT §25.8.6.2.

B. CY12 Berrians Project

This sub-section discusses the NYISO's evaluation of CY12 Berrians Project-specific components of the CONE calculation.

1. Treatment of NYC Property Tax Exemption

The NYISO assumed that the CY12 Berrians Project would be cycled in order to satisfy the requirements for the Tax Exemption.[39] This exemption is anticipated to lower the levelized carrying charge rate ("LCC") of a typical combined cycle by 3.3 percent (measured as a percent of the present value of the total investment cost).[40,41] Hence, hypothetically, if the total overnight investment cost of the CY12 Berrians Project was $2,000/kW, this exemption would lower the annual levelized CONE by $66/kW-year ICAP.

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

The CY12 Berrians Project will be located at a site with existing generators. Furthermore, the Berrians site has been designed for a total of four 250 MW generators, including the CY11 Berrians Project. A new project located on a site with existing and proposed new units might use pre-existing equipment on the site, to share equipment with other generators at the site, and to share equipment with generators that have not yet been built.

The MST requires the NYISO to estimate the CONE of an Examined Facility based on its "embedded" cost. To reasonably estimate the CONE of the Examined Facility, it is important to allocate costs appropriately across multiple generators at a single site. This sub-section discusses the criteria used by the NYISO for allocating costs to the CY12 Berrians Project if the costs are related to pre-existing and/or common (i.e., shared) facilities.

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39 The Tax Exemption for New York City peaking generators is discussed in greater detail in Sub-section VII.I.

40 The use of the LCC is described in *BSM Numerical Example*, Section 3.1.

41 The effect on a typical combined cycle unit is based on the model that was used by NERA in the 2013 Demand Curve reset process for a combined cycle unit in New York City, assuming a 30-year amortization.

The treatment of certain equipment at the Berrians site depends on whether the CY11 Berrians Project is assumed to be in service before the CY12 Berrians Project would come in service. Since the CY11 Berrians Project was mitigated and accepted its Project Cost Allocation, the assumption about whether the CY11 Berrians Project would be in service for the purposes of the CY12 BSM evaluation was made in accordance with criteria discussed in Sub-section VII.E. If the CY11 Berrians Project was assumed to be in service, any equipment it shared with the CY12 Berrians Project would be treated as a "pre-existing common facility" as described below in Part (b). If the CY11 Berrians Project was not assumed to be in service, any equipment it might share with the CY12 Berrians Project would be treated as a "new facility with multiple future uses" as described below in Part (c).

a. 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 non-common facilities at the Berrians site based on their book values.[42] The use of book values was consistent with the requirement to use embedded costs. Furthermore, we believe the book values were reasonably consistent with the likely economic costs of using the equipment for the Examined Facility.

b. 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 NRG plans to use pre-existing common facilities, the NYISO allocated costs

[42] Investopedia defines book value of an asset as "the cost of an asset minus the accumulated depreciation."

from such facilities to the CY12 Berrians Project 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.[43] We believe the NYISO's assumptions with regard to 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.

c. New Facilities with Multiple Future Uses

When a new generator is built, the developer may install equipment that will be shared by the new generator and another future generator (or other activity) at the site. Such equipment is similar to the common facilities discussed in the previous sub-section, but this subsection deals with facilities that are shared by the Examined Facility and a second generator that does not yet exist. For example, suppose $1 million is spent for a piece of equipment when an $800,000 piece of equipment would have been sufficient for the Examined Facility. If the more costly piece of equipment was installed so that a second generator could be installed later, it would not be appropriate to allocate the full $1 million to the Examined Facility. Instead, it would be appropriate to allocate $800,000 or less to the Examined Facility and at least $200,000 to the second new generator. Failing to allocate costs appropriately under such circumstances could lead to inaccurate results in current and future METs.

The NYISO allocated to the CY12 Berrians Project only a portion of the costs of equipment that might be shared with future generators at the site. To the extent that there were such pieces of equipment, the NYISO's methodology was to estimate the portion of the cost that could have been saved by using equipment that was large enough for the CY12 Berrians Project but not large enough to accommodate additional generators. Then the NYISO's next step in its

[43] This is a hypothetical example for discussion purposes, since the actual cost information for the CY12 Berrians Project is confidential.

methodology is to deduct these foregone cost savings from the equipment costs allocated to the CY12 Berrians Project. This approach is reasonable because a developer's willingness to incur additional expenses to accommodate future generators is a clear indication that those additional expenses should be allocated to the future project rather than the current proposed project. The total amount of such costs did not change the outcome of the BSM exemption test. We agree with the NYISO's approach to allocating a portion of these costs and the application of this process in its analysis of the CY12 Berrians Project.

3. Evaluation of Developer's Cost Estimate

The NYISO and its consultants applied the principles discussed in Sub-section A to evaluate various components of the cost estimates submitted by NRG. We support the NYISO decision to use the independently derived estimates to calculate some components of the CONE for the CY12 Berrians Project.

C. CHAMPLAIN HUDSON POWER EXPRESS

This sub-section discusses the NYISO's evaluation of CHPE Project-specific components of the CONE calculation.

1. CHPE Terminus

The CHPE Project is a proposed transmission line from the US-Canada border to a substation in New York City. Publicly available information indicates that the project on the Canadian side is being developed by TransEnergie.[44] The transmission line on the Canadian side is a 58 km radial line built out by TranseEnergie exclusively for the purpose of serving customers in the NYISO region.[45] The costs for the Canadian portion of the line are essential for making the CHPE Project 'used and useful' for bringing power from Canada to NYC. Therefore, the costs for the Canadian portion of the line were included in the estimated CONE for the CHPE

44 See http://www.hydroquebec.com/hertel-new-york/en/project/index.html.

45 TransEnergie is also responsible for improvements to the Hertel substation in Quebec.

Examined Facility. We support the NYISO's decision to include an estimate for the Canadian portion of the line in the CHPE Project's CONE.

2. Cost of Capacity Purchased

During the spring, summer, and fall, there is substantial excess capacity in the HQ region. However, the HQ region is likely to be capacity constrained during some of the winter months over the MSP. During such periods, the cost of capacity in the HQ region is likely to depend on the price of capacity in neighboring areas where additional capacity could be exported from the HQ region given the available interface capabilities. The NYISO considered those factors when it determined the cost of capacity for the CHPE Project. We agree that the NYISO's approach for determining the cost of the capacity for the CHPE Project was reasonable.

3. Evaluation of Developer's Cost Estimate

The NYISO and its consultants applied the principles discussed in Sub-section V.A to evaluate various components of the cost estimates submitted by TDI for estimating the CONE for the CHPE Project. We support the NYISO estimates of the CONE for the CHPE Project. The NYISO made additional CHPE Project-specific determinations which are discussed in the following sub-sections.

a. Property Taxes

The NYISO and Sargent & Lundy have reviewed the developer's information on the property values and tax rates in all the counties through which the proposed line passes. It also considered the potential for Payment in Lieu of Taxes ("PILOT") agreements.[46] We agree with that the NYISO's determination of the property tax estimates for the purposes of the BSM determination.

[46] The Commission's Order accepting the ICAP Demand Curves for the G-J Locality and the NYCA (based on a plant located in Rest of State) accepted estimated property taxes accounting for a reduction from a PILOT agreement. *See* 2014 DCR Order at P 94.

b. New York City Income Tax

The NYISO has reviewed the CHPE Project's financial and ownership structure and applied the Unincorporated Business Tax of 4 percent for the BSM evaluation. The NYISO's assumptions regarding New York City income taxes were reasonable.

D. Cricket Valley Energy Center

The NYISO's methodology for estimating the CONE for the CVEC Project included a comparison between the project information provided by the developer and an independent estimate developed by Sargent & Lundy for a combined-cycle plant with a 1 x1 x 1 configuration with similar characteristics as the CVEC Project. The NYISO and its consultants applied the principles discussed in Sub-section V.A to evaluate various components of the cost estimates submitted by the CVEC Project's developers. We support the NYISO's determination of the CONE for the CVEC Project.

E. Conclusions – Cost of New Entry

We reviewed detailed information on the NYISO's estimates of the annual levelized CONE values for the CY12 Examined Facilities. We find that the NYISO's estimates were reasonable and made in accordance with the Tariff.

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.[47] 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 CY12 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
- General criteria for making adjustments to the net revenue model
- 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 model – 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.
- HQ-NY transmission line cost estimation model – This estimates the cost to the CHPE project from procuring electricity for sale into New York City.

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

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47 Net revenues are an input to the Unit Net CONE, which is directly used in the Part B test. See *BSM Numerical Example*, Section 3.1.

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 CY12 Examined Facilities.

1. Starting Capability Period of Summer 2015

The Starting Capability Period is important because the assumed timing of entry affects the load forecast, which is used in the LBMP price forecast that is used to calculate net revenue.[48] Under the current Tariff, all three CY12 Projects are assumed to enter in Summer 2015, although it would be more reasonable to assume the projects would enter much later.[49] If the Starting Capability Period was pushed back to a more realistic date, the anticipated load growth would lead to increases in LBMPs that would result in higher forecasted net revenues for the Examined Facilities, which would reduce their Unit Net CONE values.

For the Initial Decision Round, the Starting Capability Period also had implications for the CHPE Project's cost of purchasing electricity from the HQ region (which is discussed further in Sub-section E) 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. From 2014 to 2020, it is anticipated that supply additions will exceed the forecasted growth in demand in the HQ region.[50] Thus, assuming an unrealistically early Starting Capability Period tends to reduce the estimated available energy that could be exported from the HQ region to neighboring markets below what would be likely to occur if the project actually came into service. This affects estimated net revenues by inflating the estimated cost of

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

49 The NYISO Interconnection Queue currently reports: 2016 for the CY12 Berrians Project, 2017 or 2018 for the CHPE Project, and 2018 for the CVEC Project. See "http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Interconnection_Studies/NYISO_Interconnection_Queue/nyiso_interconnection_queue.xls".

50 See 2013 Long-Term Reliability Assessment by North American Electric Reliability Corporation (December 2013) pp 117 to 119, available at: "http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf"

energy for the CHPE Project. Hence, modifying the Starting Capability Period to a more realistic date would raise the estimated net revenues for the CHPE Project.

2. Treatment of Mothballed Units and Units Transferring CRIS Rights

The NYISO forecasted LBMPs using the following assumptions as required by the Tariff: [51]

- 421.4 MW (ICAP Summer) of mothballed capacity would be offered as price-takers in New York City even though this capacity will not likely to return to service;
- Approximately 100 MW of New York City capacity that is anticipated to transfer its CRIS rights to the CY11 Berrians Project will still be participating in the capacity market as price takers even if the CY11 Berrians Project enters.

Using more realistic assumptions would tend to raise net revenues by a relatively small amount, since units in the two categories above are likely to have low capacity factors and correspondingly low impacts on forecasted LBMPs. Hence, the outcome of the Part B test for the CY12 Examined Facilities would not have been affected by the use of more realistic assumptions.

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

As in previous BSM evaluations, the NYISO started with the net revenue model that was used to derive the currently-effective Demand Curves, and then the NYISO made several changes that were suited to the BSM determination of each Examined Facility. The Commission has provided guidance regarding when it is appropriate to make adjustments to the net revenue model.[52] 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.[53] On the other hand, the Commission has indicated that using

[51] These assumptions are discussed in further detail in Sub-section VII.B.

[52] 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. Net revenues were also adjusted to account for natural gas futures prices.

[53] This Commission Determination was made in response to the complaint that use of gas futures in a MET

different inflation adjustments for the Default Net CONE and ICAP price forecast in the Part A test is inappropriate because it would not provide an "apples to apples" comparison.[54] 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 how such factors affected specific components of the net revenue model for particular projects.

C. LBMP ESTIMATION MODEL

This section describes key assumptions that the NYISO made in forecasting market clearing prices for the BSM evaluations.

1. Use of Gas Futures Prices

For the purposes of the current BSM determination, the NYISO employed a gas price-adjustment in the econometric model that was used in the Demand Curve reset. The adjustment considered how differences between the gas prices that prevailed over a three-year historic period (May

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.

54 See *Astoria Generating Company, L.P., et al. v. New York Independent System Operator, Inc.*, 139 FERC ¶ 61,244 (2012), P 61:

> To provide an "apples to apples" comparison of the projected Default Offer Floor to projected demand curve prices during the Default Mitigation Study Period, the demand curve prices projected for the one-year Default Mitigation Study Period, likewise, should reflect the same adjustment for inflation.

2011 to April 2014) and the gas prices expected by the futures market would affect the net revenues of each project. Similar adjustments were made in the Part B tests for projects in previous Class Years. The Demand Curve model used historic gas prices for the Iroquois Zone 2, Transco Zone 6 (NY), and other trading hubs to estimate the relationship of Zone LBMPs to natural gas prices. 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).[55] We support the use of this adjustment.

2. Use of RGGI Futures Prices

Operating costs for power plants in the Regional Greenhouse Gas Initiative ("RGGI") member states include the costs associated with obtaining RGGI allowances to cover their CO2 emissions. LBMPs generally reflect the marginal costs of gas-fired generation, including the cost of RGGI allowances. RGGI allowance futures prices indicate that RGGI allowance prices are expected to be higher during the MSP than during the historic three year period from May 2011 to April 2014.

No adjustment was made to the net revenues of the CY12 Berrians Project and the CVEC project to account for expected increases in RGGI allowance prices. 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.

As a transmission line, the CHPE Project's net revenues would be affected by the impact of RGGI allowance costs on prices where it would purchase and sell electricity. The NYISO adjusted Zone J LBMPs upward to reflect the effects of higher RGGI allowance costs where the CHPE Project would sell electricity.[56] Furthermore, as discussed in Sub-section VI.E below, the

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55 The econometric portion of the demand curve model is used to make the adjustment from historic gas prices to futures gas prices, and it uses the Iroquois Zone 2 price for adjusting Zone G LBMPs and the Transco Zone 6 (NY) price for adjusting Zone J LBMPs. However, the GE-MAPS portion of the demand curve model links gas trading hubs to generator nodes at a more granular level.

56 The NYISO performed the following monthly adjustment to LBMPs over the MSP:

NYISO's model for estimating the cost of energy procured by the CHPE Project depends on prices in Ontario, New England, and Western New York. Therefore, the NYISO also adjusted the prices in New England and Western New York, since they are within the RGGI region. We support the NYISO's adjustment of the expected LBMPs to account for RGGI allowance price futures.

3. Astoria Annex Delivery Constraint

The existing Astoria Energy II combined cycle generator is interconnected at the Astoria Annex, which is connected to the transmission system by two 345kV lines and one PAR-controlled 138kV line. The output of the Astoria Energy II generator is sometimes limited by transmission constraints leaving the Astoria Annex.[57] The CHPE Project and the CY12 Berrians Project have proposed to interconnect at the Astoria Annex where the Astoria Energy II combined cycle generator is already interconnected.[58] Hence, it is important to forecast the congestion that would occur between the Astoria Annex and other nodes on the 345kV system in New York City if the CY12 projects were to become operational.

The NYISO's net revenue analysis for the CY12 Berrians and CHPE projects accounted for this congestion of power being exported from the Astoria Annex. This was done through the zonal-to-nodal price adjustment that is already a standard feature of the net revenue analysis for the demand curve reset and other BSM evaluations.[59] This adjustment models intra-zonal

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RGGI price change = (Futures Price in MSP) – (Auction Price over the Historic Period)

Expected LBMP change = (Gas-Fired Emission Rate) x (Indicative Marginal Heat Rate) x (Expected RGGI price change)

The result of the above calculation was an average increment of $1.25 per MWh in the LBMPs.

57 In 2014, these constraints were binding in 2 percent of real-time market intervals.

58 The proposed CHPE Project would have been accompanied by substation upgrades and an additional 345kV transmission line exiting the Astoria Annex.

59 See Section III.D of August 2013 NERA report "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator"

congestion using GE-MAPS with a network model that includes individual 345kV and 138kV facilities and N-1 contingencies in New York City. We support the NYISO's method of adjusting the LBMPs for these projects to account for the Astoria Annex delivery constraint.

In the BSM determinations performed for the Initial Decision Round, the NYISO forecasted that Astoria Annex export constraints would reduce the LBMPs for the CHPE Project and the CY12 Berrians Project, although the constraints did not affect whether either project passed or failed for the Initial Decision Round.

In the BSM determination for the CY12 Berrians Project for the Final Decision Round, the NYISO forecasted that Astoria Annex export constraints would have very significant effects on the project's net revenues. The constraints were forecasted to reduce the average day-ahead LBMP at the Astoria Annex by 10 percent. The effects of these constraints are discussed further in Sub-section D.4.

4. Estimation of Market Clearing Prices Outside NYCA

The net revenue model developed for the last demand curve reset was designed for estimating LBMPs at pricing nodes in the NYCA. However, as discussed in Sub-section E, the calculation of net revenues for the CHPE Project also requires the NYISO to estimate market clearing prices in Ontario and New England. So, the NYISO expanded on the model from the demand curve reset to estimate market clearing prices at these external pricing locations.

For locations in NYCA, the NYISO's LBMP estimation model uses an econometric model and a GE-MAPS model. These models are used to forecast prices during the MSP by adjusting prices during the historic period (May 2011 to April 2014) to account for anticipated changes in market conditions. The econometric model is used to estimate the impact of expected changes in gas prices, while the GE-MAPS model is used to estimate the impact of changes in resource mix, load, and network topology at each node.

The GE-MAPS model was used to estimate the impact of changes in resource mix, load, and network topology on prices in Ontario and ISO New England in the same manner as was done for nodes inside NYCA. However, the econometric model from the demand curve reset was designed to forecast prices at the eleven zones in New York. So, the NYISO adjusted Ontario prices using the adjustment factors from the econometric model for the West Zone (Zone A), while the NYISO adjusted ISO New England prices using the adjustment factors for the Capital Zone (Zone F). Hence, the NYISO assumed that the impact of the causal factors that are captured by the econometric model on external node LBMPs would be the same as the impact of these factors on LBMPs at a proximate internal node. We agree that the NYISO's methodology for estimating LBMPs at the external nodes is reasonable.

D. Scheduling Model

The following subsections discuss the key assumptions the NYISO used in the scheduling model for the CY12 Examined Facilities.

1. Combined Cycle Technology

The CVEC Project and CY12 Berrians Project are combined cycle facilities, while the Demand Curve unit is a simple cycle combustion turbine unit. So, the CVEC Project and CY12 Berrians Project are expected to have lower heat rates than the Demand Curve unit. Also, combined cycle generators have the capability to provide synchronous reserves and have longer minimum run times than the Demand Curve peaking unit.

For combined cycle generators, the commitment model determines the optimal set of hours for running the unit for a 24-hour period based on DAM LBMPs and Ancillary Services prices, considering start-up costs, the actual down time of the unit, minimum run time, minimum down time, and the cost of operation at the minimum generation level. The commitment model also produces optimal DAM Energy and Ancillary Services schedules based on the incremental operating costs and the minimum generation level. For hours when the unit is committed, the dispatch model optimizes output based on RT LBMPs and Ancillary Services prices, allowing the unit to earn additional profits from balancing purchases and sales. As with the BSM evaluations for the CY11 Berrians Project and the CPV Valley Project, we support the NYISO's use of a scheduling model that is adapted for use with a combined cycle generator.[60]

2. Considering the NYC Property Tax Exemption

As discussed in Sub-section VII.I, the Tax Exemption law provides that a new generating facility in New York City may receive a significant property tax exemption if it is a peaking unit or if it runs for fewer than 18 hours per start. A new generator like the CY12 Berrians Project might normally operate for days at a time due to its relatively low operating costs. However, a competitive supplier would adjust the operating profile of its generator if the savings from lower property taxes would offset the lost net revenues and higher costs from cycling the units more frequently.

The NYISO's commitment model considered that the CY12 Berrians Project would perceive: (i) an opportunity cost for each additional hour of operation after start-up, and (ii) a benefit from each additional start-up because each start-up would enable the unit to earn additional net revenues from operating for another 18 hours. Under optimal scheduling conditions, the benefit per startup would be 18 times the opportunity cost per run-hour. So, the NYISO's commitment model determined the hours of commitment incorporating an opportunity cost per run-hour in the minimum generation offer of the unit and a benefit per start-up in the start-up offer (i.e., an offer reduction) of the unit. Based on a forecast of DAM LBMPs, the NYISO estimated the minimum generation offer increase and start-up cost offer reduction that would lead the CY12 Berrians Project to satisfy the target of 18 hours per start optimally.

As with the CY11 Berrians Project's BSM evaluation, we found this methodology to be a reasonable approximation of how a competitive supplier would optimize the use of the CY12 Berrians Project in order to obtain the Tax Exemption.[61] Furthermore, the rules for setting reference levels would allow for the inclusion of appropriate adders to reflect marginal costs,

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60 See MMU CY11 Berrians Project Report at pp 21-22, 26-27 and MMU CY12 CPV Project Report at pp 24-25, 27-28

61 See MMU CY11 Berrians Project Report at pp 28.

which would allow the unit to reflect the opportunity cost appropriately in its energy offers and avoid mitigation.

3. CHPE Scheduling Model

The NYISO's model assumed the CHPE Project's operator 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. Sub-section E describes the model that was used to forecast the expected cost of purchasing power in the HQ region during the Mitigation Study Period as well as the assumed transmission service charge. We believe this is a reasonable method of forecasting when the CHPE project would be scheduled for several reasons.

4. Astoria Annex Delivery Constraint

The existing Astoria Energy II combined cycle generator is interconnected at the Astoria Annex, which is connected to the transmission system by two 345kV lines and one PAR-controlled 138kV line. The output of the Astoria Energy II generator is sometimes limited by transmission constraints leaving the Astoria Annex.[62] The CHPE Project and the CY12 Berrians Project proposed to interconnect at the Astoria Annex where the Astoria Energy II combined cycle generator is already interconnected.[63] Hence, it is important to forecast the effects of congestion between the Astoria Annex and other nodes on the 345kV system in New York City if the CY12 projects were to become operational.

As discussed in Part 1 of this sub-section, the NYISO's scheduling model for combined cycle technology forecasts the schedules of an Examined Facility based on unit-specific cost and operating characteristics and the forecasted LBMPs at the generator's location. Also, the forecasted LBMPs include the estimated effects of intra-zonal congestion at the Astoria Annex

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62 In 2014, these constraints were binding in 2 percent of real-time market intervals.

63 The proposed CHPE Project would have been accompanied by substation upgrades and an additional 345kV transmission line exiting the Astoria Annex.

(which is discussed in Sub-section C.3). However, there was a large disparity between: (a) the schedules produced for the CY12 Berrians Project by the CC scheduling model, and (b) the schedules produced for the CY12 Berrians Project by the GE-MAPS model. Since the GE-MAPS model had a detailed representation of the Astoria Annex delivery constraints, the schedules produced for the CY12 Berrians Project by the GE-MAPS model are likely more accurate than the CC scheduling model. Hence, the NYISO adjusted down the net revenues for the CY12 Berrians Project using the ratio of the capacity factor from the CC scheduling model to the capacity factor from the GE-MAPS model.[64] We support the NYISO's method of adjusting the CY12 Berrians Project's net revenues to account for the Astoria Annex delivery constraint.

In the final BSM determination for the CY12 Berrians Project, the NYISO forecasted that Astoria Annex export constraints would have very significant effects on the project's net revenues. The constraints were forecasted to reduce the average day-ahead LBMP at the Astoria Annex by 10 percent and to reduce the estimated output of the CY12 Berrians Project significantly. Consequently, the CY12 Berrians Project's net revenues were reduced very significantly by the recognition of delivery constraints from the Astoria Annex. If the NYISO's net revenue model did not model any constraints at the Astoria Annex, the CY12 Berrians Project would likely have passed the Part B test and received a BSM exemption. Since the congestion would reduce the net revenues of the unit, it was appropriate for the NYISO to include it in their models. This is discussed further at the conclusion of this section.

E. HQ-NY Transmission Line Cost Estimation Model

The HQ region does not have a centralized wholesale spot market for electricity, so there are no transparent publicly-available spot prices that can be used to estimate the cost of purchasing electricity for export across the CHPE line. Instead, the NYISO estimated the cost of purchasing electricity based on spot prices in markets adjacent to the HQ region. The NYISO's modeling approach was designed around the following factors.

64 This was applied separately for summer and winter Capability Periods.

First, the generation portfolios of Quebec and Labrador (which is radially connected to Quebec) are dominated by hydroelectric power plants with large amounts of reservoir capacity. This allows generators to produce less output during low price periods and more during high price periods. Consequently, exports from HQ to Ontario, New York, and New England are correlated with expected price levels in adjacent markets rather than patterns of rainfall or runoff.

Second, Quebec is interconnected with several large markets via bi-directional HVDC connections, allowing marketers to move power across long distances using the HQ network based on which market is expected to have the highest prices.

Third, the overall net amount of exports from Quebec (and Labrador) to adjacent markets depends on the differential between total supply and total demand over a given year. If the net amount of exports is low, the exports will be scheduled only during hours when adjacent areas experience relatively high prices, driving-up the expected cost of purchasing electricity in Quebec. On the other hand, if the net amount of exports is high, it will drive-down the expected cost of purchasing electricity in Quebec.

The NYISO estimated the average marginal cost of purchasing power for export to neighboring markets in the following manner:

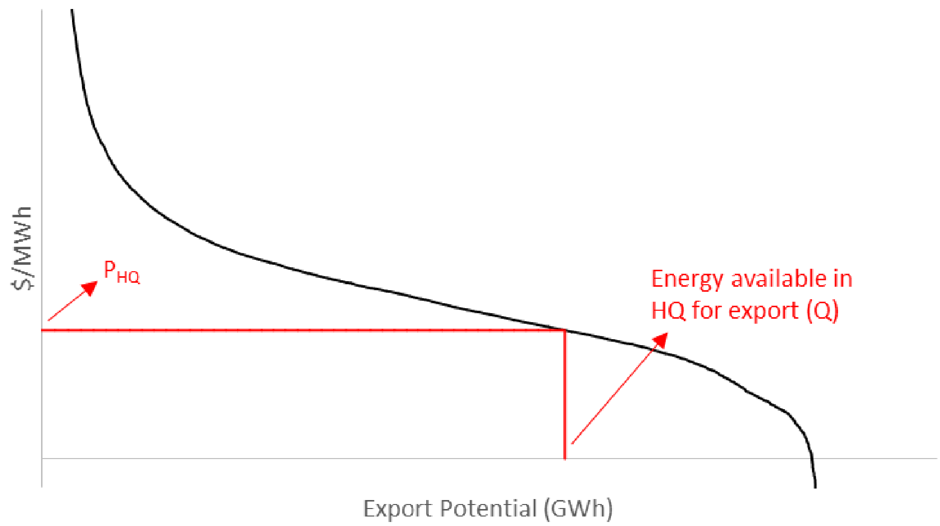
- For each neighboring market in each hour during the MSP, the NYISO determined the revenue that a marketer could earn from exporting from the HQ region. For example, in an hour when the price in ISO New England was $50/MWh and the transmission service charge was $10/MWh, a $40/MWh revenue opportunity would be reflected in an "export opportunity curve" for a quantity of megawatt-hours equal to the TTC of the interface in that hour.
- The total amount of electricity available for export across HVDC lines connecting HQ to Ontario, New England, and New York during each year of the MSP was forecasted based on: (a) net exports to neighboring markets across HVDC lines during the historic period (May 2013 to April 2014), minus (b) projected annual load growth through the end of the MSP, plus (c) planned resource additions through the end of the MSP.[65]

[65] See 2013 Long-Term Reliability Assessment by North American Electric Reliability Corporation (December 2013) pp 117 to 119, available at: "http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf"

- The total amount of electricity available for export over a given year was combined with an "export opportunity curve" to determine the marginal cost of purchasing electricity for export.

This approach is illustrated in Figure 1, which ranks the opportunities to export in individual hours in descending order based on the forecasted clearing price (minus the applicable transaction fee) for a given year. The NYISO determined the average marginal cost of purchasing electricity in the HQ region (P_{HQ}) in a given year where the opportunity curve intersects the amount of power available for export from HQ (Q) in Figure 1.

Figure 1: Export Opportunity Curve for the HQ Region



Other key assumptions the NYISO made in its model for estimating the cost of purchasing electricity in the HQ region are:

- In recent years, Quebec has imported significant quantities of power from Ontario, which has led to increased exports to New York and New England (and to Ontario in higher priced hours). Accordingly, the NYISO's model incorporated opportunities to import from Ontario into the model. The NYISO did this by ranking opportunities to import based on the forecasted clearing price in Ontario plus the applicable transaction fee. It was assumed that each MW imported would increase the total energy available for export over the year.

See Hydro Quebec's 2013 Annual Report pp 101 to 102, available at:
http://www.hydroquebec.com/publications/en/annual_report/pdf/annual-report-2013.pdf

- The maximum amount of electricity that could be transmitted across an interface in a given hour during the Mitigation Study Period was based on the TTC of the interface in a historic hour. The NYISO used the historic hour on which a particular future hour was forecasted. For example, the TTC for HB 12 on May 1, 2016 was assumed to be equal to the TTC for HB12 on May 1, 2012.
- The prices in the export opportunity curve were adjusted based on the applicable transmission service fee.
- Ontario does not have a centralized day ahead market, so day-ahead clearing prices could not be used to estimate the expected clearing prices for Ontario. Real-time clearing prices are highly volatile and subject to large price variations that are difficult for marketers to predict, making hourly real-time prices a poor indicator of prices that would have been expected by marketers. To account for this, the NYISO calculated average peak and off-peak real-time prices and used these as an estimate of expected real-time prices. The use of peak and off-peak averages in this manner is consistent with the historical pattern of marketers to schedule most power in blocks corresponding to peak and off-peak hours.

We found that the NYISO took a reasonable approach to estimating the net revenues for the CHPE project given the lack of public information on spot pricing in the HQ region. We also found that the overall results were reasonable when evaluated at a more detailed level.

F. Conclusions – Net Revenues

We reviewed detailed information on the NYISO's estimate of the reasonably anticipated net revenues of the CY12 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.

In the final BSM determination for the CY12 Berrians Project, the NYISO forecasted that Astoria Annex export constraints would have very significant effects on the project's net revenues.[66] If the NYISO's net revenue model did not model any constraints at the Astoria Annex, the CY12 Berrians Project would likely have passed the Part B test and received a BSM exemption. It was appropriate to model these constraints because they would have an impact on the project's net revenue, since they would affect the net revenue of a competitive generator. We

66 Additional details are provided in Sub-sections C.3 and D.4.

agree that the NYISO assumptions in the net revenue analysis were reasonable and compliant with the MST.

The BSM forecasts assume post-contingent flows on one of the two Astoria Annex-to-E13th St 345kV lines would be limited to the Long-Term Emergency ("LTE") transfer limit of 592 MVa in the summer and 645 MVa in the winter if the other line was to trip offline unexpectedly, limiting generation at the Astoria Annex to comparable levels. Therefore, if the CY12 Berrians Project was added beside the existing Astoria Energy II generator, the combined DMNC values of generation at the Astoria Annex would be 805 MW in the summer and 848 MW in the winter, resulting in very frequent congestion.[67] However, the Poletti steam turbine generator, which was interconnected at the Astoria Annex until 2010, routinely operated to its DMNC capability of 890 MW in the summer and winter under a similar network configuration.[68] This was enabled by an operating exception that allowed post-contingent flows to exceed the LTE of the lines, which have Short-Term Emergency ("STE") ratings of 1476 MVa in the summer and 1595 MVa in the winter.[69] A similar operating exception does not exist that would allow the CY12 Berrians Project and other generation at the Astoria Annex to exceed the LTE ratings, and the NYISO is unaware of whether such an operating exception would be feasible. Accordingly, the NYISO did not assume the existence of such an operating exception for the purposes of its net revenue forecast.

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67 Based on the Astoria Energy II DMNC in the 2014 Goldbook plus the Deliverable MWs of the CY12 Berrians Project.

68 The network configuration changed in 2012 when a PAR-controlled line was installed from the Astoria Annex to the Astoria East 138kV bus, although this results in the same post-contingent configuration for the most limiting constraints, which occur when certain stuck breaker outages cause the PAR-controlled line and one 345kV line to trip offline simultaneously.

69 See Exceptions to NYSRC Reliability Rules Revision 0 pp 6, available at: http://www.nysrc.org/pdf/Documents/Exceptions%20to%20Reliability%20Rules%20Rev%200.pdf

VII. ASSUMPTIONS AFFECTING THE PART A AND PART B TESTS

This section of the report discusses key assumptions that affect multiple components of the BSM determinations for the CY12 Examined Facilities.

A. STARTING CAPABILITY PERIOD OF SUMMER 2015

The Starting Capability Period is the capability period in which the CY12 Examined Facilities are assumed to begin operating and offering capacity for the purposes of the BSM determinations. The Starting Capability Period is important because the timing of entry affects the load forecast and other assumptions that are used in the ICAP price forecasts and the net CONE values that are inputs to the Part A and Part B tests.[70] If the Starting Capability Period is significantly earlier than an Examined Facility's likely Commercial Operation Date, it can depress the ICAP price forecasts and inflate the Unit Net CONE, thereby increasing the likelihood of mitigating an economic resource. Also, the higher Unit Net CONE may raise the Examined Facility's Offer Floor above its true net cost of entry.

The Tariff requires the NYISO to assume that Examined Facilities will be in service three years after the start of the Class Year, so the NYISO must assume that CY12 projects will be in service beginning in May 2015.[71] The three-year rule was implemented to increase the certainty of developers and market participants regarding the assumptions of BSM evaluations, and to avoid gaming of the timing a project's identification of its Commercial Operation Date . However, owners of the CY12 Projects did not learn their project's final Class Year Project Cost Allocation of SDUs and SUFs (i.e., interconnection costs) until the fourth quarter of 2014—less than a year before the projects are assumed to be operational for purposes of the BSM exemption tests. The BSM measures are intended to provide a developer with the exemption test results *before* it begins building a new facility, since a competitive supplier might not move forward

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

71 See MST §23.4.5.7.2.

with such a large investment if it was not reasonably certain to receive capacity market revenues. In order for the CY12 facilities to begin operations by May 2015, construction would have had to begin long before they learned their respective interconnection costs or BSM exemption test results. Hence, the Starting Capability Period is not well-aligned with when the Examined Facilities would likely be operational.

Although the Starting Capability Period for the CY12 Projects was determined in accordance with the NYISO Tariff, we recommend the NYISO consider modifying the Tariff so that the Starting Capability Period is better aligned with when the Examined Facilities would actually begin operating.[72]

B. Treatment of Mothballed Units, Recently Retired Units, and Units Transferring CRIS Rights in Price Forecasts

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 $13.77 per kW-year UCAP in the Part A test.

The LBMP price forecasts are also affected by both the quantity of in-service resources and the anticipated capacity factor of the resources. High-capacity factor resources have more impact on LBMPs than low-capacity factor resources. Since generators nearing retirement generally have

72 Revisions to the NYISO's OATT were made to encourage projects to move through future Class Year processes in a more timely manner (this will be fully effective for Class Years after CY12). (*See New York Independent System Operator, Inc.*, Proposed Tariff Revisions Regarding Interconnection Process Improvements, Docket No. ER13-588-000, delegated letter order April 1, 2013.) However, it is likely that the process will still take 12 to 18 months before a project receives a final BSM determination, so some additional changes are necessary for the Starting Capability Period to be well aligned with when an Examined Facility might be expected to begin operating.

low capacity factors, the treatment of units discussed in this sub-section has less impact on the forecasted net revenues than on the forecasted capacity prices in the CY12 BSM evaluation.

The treatment of existing capacity in the BSM evaluation is governed by the Tariff's definition of Expected Retirements and subsequent Commission Orders.[73,74,75] This section of the report discusses how the treatment of the following three categories of generation affects capacity and LBMP price forecasts: mothballed units, recently retired units, and units that propose to transfer their CRIS rights to a new resource.[76]

Mothballed Capacity – The NYISO has included in its price forecasts 421.4 MW of mothballed capacity (ICAP Summer) for Zone J.[77] In some cases, it is realistic to assume that a mothballed unit with no significant equipment failures would re-enter the market if capacity prices rose to the levels that might induce new investment in generation. However, the requirement to do this in all cases will generally lead to unrealistically low capacity and LBMP price forecasts because:

- Mothballed units may face significant costs to re-enter, particularly if this would require significant repairs or other capital expenditures; and
- Suppliers with large generation portfolios that include mothballed units may not have competitive incentives to re-enter the market, since this would lower the capacity prices

73 Existing resources are included in the ICAP price forecast and the LBMP forecast at their CRIS-adjusted DMNC values. SCRs' capacity values are based on the most recently published Gold Book data.

74 The Commission has stated that Expected Retirements as defined in MST §23.4.5.7.3.2 includes *only* resources that have filed a retirement notice with the New York Public Service Commission. *See New York Independent System Operator, Inc.*, 143 FERC ¶ 61,217 (2013) at P 111("June 2013 Order"). This does not include resources that are mothballed or that a supplier plans to replace with a new resource.

75 Although MST §23.2 at definition of Unit Net CONE or § 23.4.5.7.3 *et. seq.* does not specify which resources should be treated as existing for the purposes of the LBMP forecast, the Commission has determined that it should be the same as the set of resources included for the purposes of the ICAP forecast. *See Hudson Transmission Partners, LLC v. New York Independent System Operator, Inc.*, 145 FERC ¶ 61,156 (2013) at PP 87 - 88.

76 The effects of such treatment in the Part A test, the Part B test, and the net revenue forecast are discussed in Sections III.A.2, IV.A.2, and VI.A.1.

77 The amount of mothballed capacity is normally reported in the BSM CY12 Forecast Assumptions.

for other units in the portfolio. There are currently no mitigation measures that would compel a supplier to return a mothballed unit to service if it were economic to do so.

Suppliers may keep their units in a mothballed state for up to three years before their CRIS rights are forfeited, or they can re-enter the market before that period ends. Although the NYISO's inclusion of mothballed units in the capacity price forecasts was done in accordance with its Tariff, we believe there is a substantive deficiency in this methodology. The Commission has acknowledged this problem and has encouraged the NYISO to work with stakeholders to consider amending the BSM rules.[78]

Recently Retired Capacity – Although the previous owners of the 500 MW (ICAP Summer) Danskammer plant filed a retirement notice with the New York Public Service Commission ("PSC") in January 2013, the current owners of the facility filed a petition for the PSC to reconsider.[79] The PSC approved the petition from the current owners on June 27, 2014 and the owners signed a power purchase agreement with Central Hudson.[80] The NYISO has included the Danskammer plant in its ICAP price forecast for the CY12 BSM evaluation, since the plant has effectively withdrawn its retirement notice and no longer meets the criteria for an Expected Retirement. We support the NYISO's decision to include this capacity as part of the ICAP forecast for the CY12 BSM evaluation.

Although the treatment of the Danskammer plant in this case is consistent with the reasonably expected outcome, the current criteria for deeming a generator retired for the purposes of the BSM evaluation may lead to inflated price forecasts under two circumstances in future BSM evaluations. First, if the CY12 BSM evaluation had been conducted several months earlier, the plant would likely have been excluded from the forecasts even though its return to service was

78 *See* June 2013 Order at P 111.

79 *Notice of Intent to Retire Dynegy Danskammer, L.L.C. Units 1 – 6* (January 3, 2013), available at: "http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planned_Generation_Retirements/Planned_Retirement_Notices/Danskammer_Retirement_Notice.pdf".

80 NYPSC Docket No. 14-E-0117, *Order Approving Transfer and Making Other Findings* (June 27, 2014), available at: ""http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={69C91C0A-54AA-4889-A85A-AE376A4A683B}".

widely expected. Second, filing a retirement notice with the PSC is not binding and does not necessarily prevent a unit from returning to service, so the current criteria for Expected Retirements may lead units to be excluded from the forecast even when its retirement is unlikely. Hence, it would be beneficial for the NYISO to work with stakeholders to improve the BSM rules relating to the treatment of recently retired units in the price forecasts.

Units Transferring CRIS Rights – The NYISO has included approximately 100 MW of capacity in the forecast that must retire and relinquish its bus positions and transfer its CRIS rights in order for the CY11 Berrians Project to become fully deliverable.[81] Although it is generally reasonable to assume in-service units will remain in service throughout the MSP, it is illogical to assume out-going generators would sell capacity at the same time as a project that would use their interconnection rights. The NYISO's treatment of such generators in the price forecasts is in accordance with the Tariff, but we believe that rule changes should be considered so that more reasonable assumptions can be made in the future.

C. Impact of Imports from PJM to New York City on Capacity Price Forecast

The BSM exemption tests require the NYISO to estimate the effects on capacity prices of transmission lines that possess Unforced Capacity Deliverability Rights ("UDRs"). The assumptions regarding such transmission lines possessing UDRs are important, since there is currently 1 GW of potential UDR capacity 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

81 The circumstances of units relinquishing CRIS rights to the CY11 Berrians Project is discussed further in *Assessment of the Buyer-Side Mitigation Exemption Test for the Berrians Facility* (October 15, 2013) at pp. 7-8, available at: "http://www.nyiso.com/public/webdocs/markets_operations/services/market_monitoring/ICAP_Market_Mitigation/Buyer_Side_Mitigation/Class_Year_2011/Berrians%20MET%20MMU%20Report__10-15-13.pdf".

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

When conducting the BSM exemption tests for the CY12 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 in the neighboring market.[82] 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.

D. Impact of Other Imports on Capacity Forecast

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.

1. Imports to Zone K (Long Island)

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 Neptune line and Cross Sound Cable would

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82 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.

remain at recently observed levels throughout the MSP. We agree that this is a reasonable assumption given historic import patterns.

2. Net Imports to Zones A-F

The NYCA's interfaces with neighboring Control Areas allow external resources from PJM, Hydro Quebec, and ISO-NE to offer capacity into the Rest of State (*i.e.*, 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. Exports to neighboring areas may be limited by internal criteria or by criteria that is determined by the neighboring control area.[83]

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.[84] Within these limits, the NYISO assumed that capacity would be imported from PJM when the NYCA capacity prices are higher and exported to PJM when the NYCA capacity prices are lower.[85]

ISO-NE Interface - For the interface with ISO-NE, the NYISO followed a similar approach as described for the PJM interface above for the first two years of the MSP.[86] However, the capacity prices in the ISO-NE's Forward Capacity Auction (FCA) are set to rise substantially in

83 See presentation *Import Rights Deliverability Assessment*, by Steven Corey, Joint ICAP/Market Issues Working Group (February 4, 2014)].

84 The External Rights Availability for the Summer 2014 Capability Period is 300 MW from ISO New England, 0 MW from Ontario, and 1,080 MW from PJM. *See* Installed Capacity Manual Section 4.9.6. Over the past three years, the observed maximum net export levels were 126.4 MW to ISO New England, 0 MW to Ontario, and 194.1 MW from PJM.

85 The cost of PJM capacity is based on an average of clearing prices for the MAAC Local Delivery Area of $167.46/MW-day for the 2015/16 BRA, $119.13/MW-day for the 2016/17 BRA and $120.00/MW-day for the 2017/18 BRA.

86 The cost of ISO-NE capacity is based on an average of clearing prices for ISO-NE Rest of System of $3.43/kW-month in FCA 6 (2015/16) and $3.15/kW-month in FCA 7 (2016/17).

the last year of the MSP (the 2017/18 Capability Year) because of several significant retirements. Furthermore, the FCA for 2017/18 was the first in which ISO-NE did not use a price floor, reducing the amount of capacity that is likely to become available to the NYISO market after the FCA. For the purposes of the BSM determination, it is reasonable to assume that capacity exports from the NYISO region to ISO-NE will increase in the 2017/18 Capability Year as a result of these changes. Hence, for the last year of the MSP, the NYISO assumed net exports to ISO-NE based on the results of (i.e., which NYISO resources were sold in) FCA 8.[87]

HQ Interfaces – Although Quebec exports large amounts of capacity to neighboring control areas, Quebec 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 HQ would export 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., 2011/12, 2012/13, and 2013/14);
- Plus forecasted increase in supply resources in Quebec;[88]
- Minus forecasted increase in capacity requirement for Quebec because of load growth;[89]
- Minus forecasted exports to New York City across the CHPE transmission line. (Initial Decision Round Only)[90]

87 See FCA 8 results at: "http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp18/index.html".

88 See 2013 Long-Term Reliability Assessment by North American Electric Reliability Corporation (December 2013), available at: "http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf".

89 See study on 2013 Long Range Adequacy Overview by Northeast Power Coordinating Council (February 26, 2014), available at: "https://www.npcc.org/Library/Resource%20Adequacy/Approved2013LongRangeOverview(February%2026_2014).pdf".

90 For the Initial Decision Round (*i.e.*, before the CHPE Project dropped out of the CY12 process), forecasted capacity purchases in Quebec by the CHPE Project would affect the amount of net imports to Western New York from Quebec based on criteria described in Sub-section V.C.2.

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 2011 to April 2014. This resulted in assumptions of 1078 MW of net imports in the Summer Capability Period, November, and April, and net imports that varied during the remaining months of the Winter Capability Periods of the MSP.

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

E. Treatment of 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 project cost allocation in a previous Class Year but have not begun construction. The developer of a new project must post security for the amount of the Project Cost Allocation, but there is no guarantee that such a project will eventually be built. In some cases, the Project Cost Allocation 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. 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 price 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 Unit Net CONE of CY12 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 develop a reasonable approach for 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.

Prior-CY Projects that were determined to be exempt were included in the price forecasts. 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 CY12 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. The specific criteria for including a mitigated Prior-CY Project is as follows: [91]

Step 1: Threshold Assumptions:

- Include Prior CY Projects that were determined to not be exempt from BSM provided the project has incurred or expended, in the aggregate, more than 5 percent of the project's cost of new entry for the following: engineering, procurement, and construction costs; financing costs; or interconnection costs invoiced by the interconnecting Transmission Owner(s), *e.g.*, Transmission Owner attachment facilities, System Deliverability Upgrades, and System Upgrade Facilities; net of any amounts that would likely be recouped if the project was not completed (*e.g.*, a deposit that would be returned) ("5 percent threshold").
- Proceed to "Step 2" for Projects that have not met such 5 percent threshold.

Step 2: Prior CY Projects that have not met the 5 Percent Threshold:

- For each Prior CY Project, examine whether it would earn sufficient capacity revenue to recoup its Unit Net CONE, considering its Offer Floor, in a capacity price forecast for a three-year period starting one year before the Class Year 2012 MSP, and which does not include the current Class Year Examined Facilities (i.e., for the Class Year 2012 determinations, Step 2 utilizes Capability Years 2014/2015, 2015/2016, and 2016/2017.) If a Prior CY Project earns sufficient capacity revenue under this test, it is included in the BSM ICAP Forecast.

The NYISO's treatment is reasonable given the uncertainty about whether Prior-CY Projects will ever enter service. Ultimately, the treatment of mitigated Prior-CY Projects in the CY12 BSM exemption tests did not have an impact on whether the Examined Facilities received an exemption.

91 These criteria are also described in the BSM CY12 Forecast Assumptions at Section 3.8.

F. 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 mitigated under the BSM rules. An Offer Floor is imposed on such resources until the resource clears for 12 months, which do not have to be consecutive.[92] 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 mitigated capacity, including the mitigated units from Prior-CY Projects in accordance with Sub-section VII.E.

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 during not only the MSP, but also during the months leading up to the MSP. Accordingly, if a mitigated unit was expected to sell capacity in the months 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 portions of the MSP. The price level of the Offer Floor of a mitigated unit was adjusted annually for inflation, using the 2.2 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.

G. 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

92 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.

Class Year are economic. The NYISO addressed this as part of the CY12 BSM evaluation for the Initial Decision Round in the following manner:

- In the Part A test, the three CY12 Projects were assumed to offer as price takers (i.e., at $0) in the one-year ICAP price forecast. If the resulting price forecast was greater than the Default Net CONE, all Examined Facilities would be exempt under the Part A test.[93]
- In the Part B test, the three CY12 Projects were assumed to offer at the lower of their Unit Net CONE and Default Net CONE in the ICAP price forecast. If the resulting price forecast was greater than the Examined Facility's Unit Net CONE, the facility would be exempt under the Part B test.[94]

The remainder of this section discusses the following concerns with the Part A and Part B test procedures that are used when multiple Examined Facilities are being tested:

- The Part A test procedure does not "recognize…Generators and UDR facilities will clear from lowest to highest."[95]
- The Part B test procedure is reasonably consistent with the requirements of MST §23.4.5.7.3.2, but we are concerned that the procedure might lead to unintended consequences in future BSM determinations under certain circumstances. We believe the requirements of MST §23.4.5.7.3.2 could be applied to the Part B test in a manner that would avoid such unintended consequences.

Ultimately, these issues did not affect the results of the evaluation for the CY12 Projects, but it could affect the result of a future BSM evaluation. Hence, we recommend the NYISO consider modifying the test procedure to address the concerns described above. The following paragraphs discuss these concerns and some of the potential ways to address them in greater detail.

<u>Part A Test</u> – The ICAP price is forecasted assuming all Examined Facilities offer as price takers, resulting in the same ICAP price forecast for each Examined Facility. Therefore, this procedure results in the same determination for all the Examined Facilities irrespective of their

93 The purpose of the Part A test is to exempt an Examined Facility when its capacity is needed to avoid a capacity deficiency in a particular locality.

94 The purpose of the Part B test is to exempt an Examined Facility that is expected to be economic (i.e., earn sufficient revenue from the NYISO markets to be profitable) based on its Unit Net CONE.

95 MST §23.4.5.7.3.2.

economics or size. This procedure does not allow the NYISO to exempt a subset of the Examined Facilities when necessary to avoid a local capacity deficiency. Hence, it would be possible for the BSM evaluation to mitigate all Examined Facilities even when (a) the locality faces capacity shortfall conditions, and (b) the shortfall could be avoided by a subset of the Examined Facilities. We believe this type of scenario could be avoided if the Part A test procedure recognized that the Examined Facilities would clear from lowest to highest.

Part B Test – The ICAP price is forecasted assuming all Examined Facilities offer at their presumptive Offer Floor (i.e., the lower of Unit Net CONE and Default Net CONE as if they were mitigated), so it is possible for an Examined Facility to set the forecasted price in some of the capability periods during the MSP under the NYISO's approach. In such a case, a portion of its capacity would not clear in the price forecast, indicating that the Examined Facility would not be expected to earn sufficient revenue at the forecasted price to be economic.[96] Hence, an Examined Facility that is uneconomic could pass the NYISO's Part B test if it fully cleared in just one Capability Period and partially cleared in the other five Capability Periods.[97]

Potential Alternative Procedure

We recommend the NYISO consider applying MST §23.4.5.7.3.2 to the Part A and Part B tests using an alternative procedure that addresses the concerns described above. The following

96 In such a case, if the price was forecasted assuming the Examined Facility was offered as a price taker (as would be expected if the project received a BSM exemption), all of its capacity would clear and the forecasted capacity price would be lower than its Unit Net CONE, supporting the conclusion that the Examined Facility is not expected to be economic.

97 To illustrate, suppose an Examined Facility has a presumptive Offer Floor of $10/kW-month in the summer and $5/kW-month in the winter, and the forecasted capacity prices are $10/kW-month, $10/kW-month, and $12/kW-month during the three summer Capability periods during the MSP and $5/kW-month, $5/kW-month, and $5/kW-month during the three winter Capability Periods during the MSP. This could occur if the large size of the Examined Facility resulted in its setting the clearing price in most periods. In this case, the annualized Offer Floor would be $90/kW-year, and the average Capacity Price would be $94/kW-year, so the Examined Facility would receive an exemption. However, further suppose that if the Examined Facility were offered as a price taker, the forecasted capacity prices would be $6/kW-month, $9/kW-month, and $12/kW-month in the three summers and $2/kW-month, $3/kW-month, and $4/kW-month in the three winters. This would result in an average capacity price of $72/kW-year, implying that the Examined Facility would not be economic during the MSP.

discusses one potential alternative procedure, although there may be other ways to apply this tariff provision that would also be appropriate.

First, in the Part B test, the alternative procedure could recognize that if a project receives an exemption, it would be expected to offer as a price taker and sell its full capacity (as assumed in the Part A test). This way, the ICAP price forecast in the Part B test would reflect that if a project enters with a BSM exemption, it tends to lower capacity prices. Second, the NYISO's alternative procedure could "recognize…Generators and UDR facilities will clear from lowest to highest" in the Part A and Part B tests by testing the Examined Facilities sequentially from lowest to highest based on their presumptive Offer Floors.

Specifically, the NYISO could first test 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 would be included in the test for subsequent Examined Facilities. This procedure would ensure that if one of two Examined Facilities was economic, sales from the more expensive project would not cause the capacity price to drop and lead the less expensive project to appear uneconomic.

H. Testing a Single Examined Facility

Sub-section VII.G describes the procedure that the NYISO uses in the Part A and B tests when multiple Examined Facilities are being evaluated.[98] The NYISO uses the same procedure when a single Examined Facility is being tested alone. Specifically, in the Part A test, the NYISO assumes that the Examined Facility would act as a price taker (i.e., offer $0). In the Part B test, the NYISO assumes that the Examined Facility would offer at the lower of its Default Net CONE or Unit Net CONE.

No other Examined Facility was tested for the Final Decision Round along with the CY12 Berrians Project, but the NYISO applied the procedure that is prescribed for multiple Examined Facilities in the Part B test that is set forth in MST §23.4.5.7.3.2. The Tariff is not explicit about

[98] This procedure is illustrated in *BSM Numerical Example*, Section 6.2.

what to assume when only one Examined Facility is being tested, but MST §23.4.5.7.3.2 implies that the NYISO should assume all of the capacity is sold from an Examined Facility when it is the only one being tested. Ultimately, the assumption made by the NYISO did not affect the outcome of the Part B test for the CY12 Berrians Facility, but there are circumstances when this assumption could lead an Examined Facility to pass the Part B test inappropriately. Therefore, in future BSM evaluations, we recommend the NYISO assume that all of the Examined Facility's capacity is sold when it is the only Examined Facility being tested.

I. Treatment of NYC Property Tax Exemption

In New York City, a substantial portion of the annual levelized cost of new entry depends on the forecasted property tax obligations of the new resource. The normal effective property tax rate for businesses in New York City is 4.63 percent, adding approximately $88/kW-year ICAP to the cost of new entry for a new peaking unit.[99] However, the currently-effective New York State Real Property Tax Law ("Tax Exemption") states that a new generating facility in New York City may receive a limited exemption if it is a peaking unit or if it runs for fewer than 18 hours per start.[100] New combined cycle units like the CY12 Berrians Project are generally expected to operate for days at a time due to their relatively low operating costs. However, the savings from the Tax Exemption far exceed the profits that a combined cycle unit would earn from operating for longer than 18 hours per start.

The NYISO assumed in the BSM exemption test that the CY12 Berrians III unit would cycle on and off as needed to satisfy the 18 hours per start provision so they can receive the Tax Exemption. This is reasonable because the increased start-up costs and reduced net revenues would be far outweighed by the benefit of the lower property taxes.

99 Assumes an overnight investment cost of $1,899/kW from the 2014 Demand Curve Reset model (dated August 22, 2013).

100 The tax law states that the exemption applies to a generating unit that "…has an annual average operation, during the calendar year preceding the taxable status date, of less than eighteen hours following each start of the unit…" NYS Real Property Tax Law Subdivision 17 of section 489-aaaaaa (Ch. 59, L. 2014 at Part GG, Subpart C; amending and extending the tax law enacted in 2011.)

VIII. Conclusions and Recommendations

In the Initial Decision Round, the NYISO evaluated three CY12 Examined Facilities: the CY12 Berrians Project, the CHPE Project and the CVEC Project. The NYISO provided the BSM determination results to each developer confidentially. We reviewed materials documenting the NYISO's evaluation of investment costs, the reasonably anticipated LBMPs and net revenues, and capacity price forecasts for the three CY12 Examined Facilities. We conclude that the results of the Part A and Part B tests for the Initial Decision Round were in accordance with the requirements of the Tariff.

In the Final Decision Round, the CY12 Berrians Project did not pass the Part A or Part B test, so it is not exempt from an Offer Floor. If the CY12 Berrians Project becomes operational in the future, an Offer Floor will be imposed at the lower of the Default Net CONE and the project-specific Unit Net CONE. We conclude that the results of the Part A and Part B tests for the Final Decision Round were in accordance with the requirements of the Tariff.

Ultimately, the primary reason why the CY12 Berrians Project did not receive an exemption in the Part B test was because transmission constraints on exports from the Astoria Annex (where the CY12 Berrians Project would interconnect) would dramatically reduce the forecasted net revenue earned by the project. We find that the CY12 Berrians Project would likely have received an exemption if these transmission constraints were not reflected in the NYISO's net revenue model.[101] It was appropriate for the NYISO to reflect this congestion in its net revenue estimates, since the congestion would diminish the net revenues that would be earned by a competitive supplier selling at the Astoria Annex.[102]

101 The forecasted impact of these constraints on the Part B test for the CY12 Berrians Facility is discussed in Sub-section IV.B.3.

102 Although the ratings of the lines exiting the Astoria Annex are sufficient for the CY12 Berrians Project to receive 250 MW of Deliverable MW for the purpose of selling capacity, the ratings do cause frequent congestion in the NYISO's forecast of net revenues from energy sales. Prior to 2010, an operating exception had allowed these lines to be operated to higher ratings, but no operating exception currently exists that would allow the use of higher ratings. Accordingly, the NYISO's evaluation assumed no operating exception. Additional details about this issue are provided in Sub-section VI.F.

The report identifies two improvements to the BSM evaluation assumptions that do not require tariff modification and that we recommend the NYISO adopt in future evaluations. (These are indicated in Table 1 by an "I" in the last column.)

The report also identifies three issues with the Tariff that, if addressed, would improve the accuracy of the capacity price forecast and the Unit Net CONE. Accordingly, we recommend that the NYISO address these with future tariff modifications. We find that if two of these issues had been addressed before the CY12 evaluation, it is possible that it would have changed the outcome of the Part A test for the CY12 Berrians Project.[103] This illustrates the importance of tariff changes that improve the accuracy of the BSM evaluations.

Table 1: Summary of Recommended Enhancements to BSM Evaluation

Issue:	Section:	Rec:
Estimating Interconnection Costs for Examined Facilities	V.A.5	T
Starting Capability Period	VII.A, (In Part A test: III.B.1, In Part B test: IV.B.1, In Net Revenue: VI.A.1)	T
Treatment of Mothballed Units, Recently Retired Units, and Units Transferring CRIS Rights in Price Forecasts	VII.B, (In Part A test: III.B.2, In Part B test: IV.B.2, In Net Revenue: VI.A.2)	T
Test Procedure for Multiple Examined Facilities	VII.G, (In Part A test: III.A, In Part B test: IV.A)	I
Test Procedure for a Single Examined Facility	VII.H	I

103 See discussion in Sub-section III.B.3.