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INDEPENDENT POWER PRODUCERS OF NEW YORK

Via E-mail to *mseibert@nyiso.com* **&** *rpatterson@nyiso.com*

October 9, 2020

Mr. Daniel Hill
Chairman of the NYISO Board of Directors
c/o Mr. Rich Dewey
President & CEO
New York Independent System Operator, Inc.
10 Krey Boulevard
Rensselaer, NY 12144

Re: Comments of Independent Power Producers of New York, Inc. on Proposed NYISO Installed Capacity Demand Curves for 2021-2025 and Request for Oral Argument

Dear Chairman Hill:

In accordance with Sections 5.14.1.2.2.4.9 and 5.14.1.2.2.4.10 of the New York Independent System Operator, Inc's ("NYISO") Market Administration and Control Area Services Tariff and Section 5.6.6. of the NYISO's Installed Capacity Manual, enclosed please find comments of Independent Power Producers of New York, Inc. ("IPPNY") to the NYISO Board of Directors on the NYISO Staff's *Proposed NYISO Installed Capacity Demand Curves for Capability Year 2021/2022 and Annual Update Methodology and Inputs for the 2022-2023, 2023-2024, 2024-2025 Capability Years.*

Additionally, IPPNY respectfully requests the opportunity to engage in oral arguments before the NYISO Board of Directors on the issues addressed in the enclosed submission and those of other market participants.

Respectfully submitted,

Matthew Schwall
Matthew Schwall
Director, Market Policy &
Regulatory Affairs

I. INTRODUCTION AND EXECUTIVE SUMMARY

Independent Power Producers of New York, Inc. ("IPPNY")[1] respectfully submits the following comments to the New York Independent System Operator, Inc. ("NYISO") Board of Directors (the "Board") on NYISO Staff's final recommendations for its *Proposed NYISO Installed Capacity Demand Curves for the 2021-2022 Capability Year and Annual Update Methodology and Inputs for the 2022-2023, 2023-2024, and 2024-2025 Capability Years* (the "Final Report").[2] In the Final Report, NYISO Staff expressly concurs with the vast majority of recommendations of the NYISO's independent consultants, prepared by Analysis Group Inc. ("AGI") and Burns & McDonnell ("BMCD") (collectively, the "Consultants"), in the *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report* (the "Final Consultants' Report") for this Demand Curve Reset ("DCR") process.[3]

IPPNY and its members have actively participated in the DCR meetings and IPPNY has submitted extensive comments in response to the Consultants' initial draft report (the "July 1 Comments")[4] and then again in response to the NYISO Staff's draft recommendations (the

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[1] IPPNY is a trade association representing companies involved in the development of electric generating facilities including renewable resources, the generation, sale, and marketing of electric power, and the development of natural gas and energy storage facilities in the State of New York. IPPNY member companies produce a majority of New York's electricity, utilizing almost every generation technology available today, such as wind, solar, natural gas, oil, hydro, biomass, energy storage, and nuclear.

[2] *See Proposed NYISO Installed Capacity Demand Curves for the 2021-2022 Capability Year and Annual Update Methodology and Inputs for the 2022-2023, 2023-2024, 2024-2025 Capability Years* (September 2020), available at https://www.nyiso.com/documents/20142/14526320/NYISO-Staff-Final-DCR-Recommendations.pdf/ed674d38-b08a-5287-925a-05dbdbe702fc.

[3] *See Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report* (September 9, 2020), available at https://www.nyiso.com/documents/20142/14526320/Analysis-Group-2019-2020-DCR-Final-Report.pdf/0dc75930-e651-2120-80de-234d98cd548b.

[4] July 1 Comments, available at https://www.nyiso.com/documents/20142/13609298/IPPNY-Comments-on-DCR-Initial-Draft-Report-7-1-20.pdf/8c17b9d8-a0b4-587b-b857-f94582642637.

"August 24 Comments").[5] IPPNY supports various aspects of Staff's Final Report, but many of our concerns with recommendations that originated in the Consultants' report and are now supported by Staff remain.

As compared to the 2020-2021 Demand Curve reference point prices, NYISO Staff's recommendations result in reference point prices for 2021-2022 that are as much as 20% lower in certain load zones.[6] This dramatic year-to-year drop in reference point price is not solely attributable to the change in proxy peaking technology from the F-Class to the H-Class Frame Turbine. Rather, much of the decrease in reference point price is attributable to: (i) theoretical economic models and assumptions that low-ball the cost of investment while discounting evidence provided by IPPNY and its members of actual investment costs; and (ii) significantly underestimating the impact of existing laws, regulations, out of market contracts, and New York's unique political and regulatory climate on merchant investment. Critically, reliability analyses issued by both the NYISO and Con Edison demonstrate that the State's public policy initiatives will drive retirements which result in significant reliability needs on the New York system by 2023, *i.e.*, during *this* DCR period.[7] Reference point prices must be adequate for the system to attract sufficient new, and retain sufficient existing, dispatchable resources in the short term to address these needs and ensure that New York maintains the necessary resource

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[5] August 24 Comments, available at https://www.nyiso.com/documents/20142/14871137/IPPNY-Comments-on-NYISO-Staff-DCR-Draft-Recommendations-8-24-20.pdf/bd2b0b25-21a4-6c92-8c8a-7aab8d01df98.

[6] *See DCR Results 2020-2021*, ICAP Monthly Reference Point Price ($/kW-Month), available at https://www.nyiso.com/documents/20142/8478044/DCR-Results-2020-2021.pdf/f9aaf751-a887-5dc9-f78a-b63578025b56.

[7] See 2020 RNA Preliminary (1st Pass) Reliability Needs (June 19, 2020), available at https://www.nyiso.com/documents/20142/13200831/02%202020RNA_1stPassRN.pdf/8a0de336-bd24-1260-dc4b-5df58cdb049f; see also 2020 RNA Con Edison Preliminary Findings (June 19, 2020), available at https://www.nyiso.com/documents/20142/13200831/03%202020%20RNAConEd%20Local%20System%20Base%20Case%20Assessments%20Results.pdf/17424cd7-3cef-3637-2388-5a27654af266.

adequacy for a reliable system over the long term. Indisputably, the need to do so has only become more immediate since the last DCR process was completed given the aggressive advancement of the State's Clean Energy Standard ("CES") program as further heightened by the enactment of the Climate Leadership and Community Protection Act (the "Climate Act") and augmented by the Renewable Siting Act in the intervening period.

Nonetheless, some market participants in the stakeholder process have requested modifications to Staff's Final Report which would unreasonably drive down reference prices. The NYISO has rightfully rejected some of these requests and made other reasonable recommendations that the Board should support. However, there are aspects of Staff's Final Report that do *not* take into account real world information, rest on flawed assumptions and are materially deficient, and thus, are not just and reasonable because they do not produce the price signals needed to support adequate investment to maintain the long-term reliability of the system. IPPNY therefore urges the NYISO Board to direct Staff to correct these errors in its Final Report as established herein and file these corrections in its Demand Curve filing with the Federal Energy Regulatory Commission ("FERC") in November.

As discussed in greater detail below, the Board should adopt Staff's recommendations that:

a) There must be no "one-time adjustments" to omit Energy and Ancillary Services ("EAS") prices for the months affected by COVID-19, as has been suggested by some stakeholders;

b) Selective Catalytic Reduction (“SCR”) emissions control technology must be included in the assumed Net Cost of New Entry (“CONE”) of the Zone G Dutchess County proxy peaking unit; and

c) A dual TGP Z4 (200L)/Niagara gas hub approach must be used in the non-winter and winter months, respectively, for purposes of calculating Net EAS revenues for the Zone C proxy peaking unit.

IPPNY requests that the NYISO Board of Directors direct Staff to make the following modifications to the Final Report:

a) Reduce the amortization period from 17 years to 15 years;

b) Increase Return on Equity (“ROE”) and explicitly account for the cost of financial hedging in the cost of building the proxy unit;

c) Increase pipeline construction and NYC site leasing costs to reflect the actual costs incurred by New York developers in recent years; and

d) Retain Iroquois Zn2 as the gas hub for the proxy peaking plants in the G-J Zone and reject the TETCO M3 gas hub because it does not present a viable alternative for the plant to procure gas and will jeopardize reliability.

II. THE BOARD SHOULD SUPPORT NYISO STAFF’S AND THE CONSULTANTS’ RECOMMENDATION THAT THERE BE NO “ONE-TIME ADJUSTMENTS” TO EXCLUDE ANY PERIOD OF HISTORIC EAS PRICES AS PART OF THIS DCR PROCESS.

IPPNY strongly supports the recommendation of NYISO Staff and the Consultants that there be no “one-time adjustment” to the historic Net EAS revenues used for purposes of setting the reference point prices as part of this DCR process. Certain stakeholders have requested that a "one-time adjustment" be made to exclude any EAS market prices for the period September 1, 2019 through August 31, 2020 as a result of the COVID-19 pandemic. The request, if granted, would suppress the resulting higher reference point prices that appropriately balance the loss of EAS revenues that occurred during the period in question. This balancing was an intentional design element of the Annual Update process as accepted as just and reasonable by FERC in its 2016 order accepting revisions to the DCR process. Specifically, FERC found that annually updating the DCR process would "reduce the potential for significant changes in the values of the ICAP demand curves from one reset to the next, a benefit that will promote greater stability and predictability of future capacity market outcomes to the benefit of all market participants and potential developers."[8] Updating the Demand Curves using the most recent historic conditions is also necessary to assure that the Demand Curves are designed to provide the missing money that suppliers are unable to derive from EAS revenues. Likewise, the historic three-year approach was lauded as a far more transparent and predictable mechanism that would permit stakeholders to tabulate Net EAS revenues. Throwing out years where those revenues are suppressed by market conditions on a one-off basis overrides the Demand Curve's ability to provide the missing money. In addition, it would stymie the very transparency this enhancement was designed to foster, leaving stakeholders to face the same "black box" as in the past, just under a different name. Such action would thus indisputably result in Demand Curves that are not just and reasonable.

[8] *N.Y. Indep. Sys. Operator, Inc.*, 156 FERC ¶ 61,039 (2016) at P 11.

Suppliers have been, and continue to be, harmed by low EAS revenues in this COVID-19 period, and depend on just and reasonable determinations of ICAP market revenues to weather these periods of low EAS prices so that they may continue to contribute to resource adequacy requirements over the long term. When the 2016-2017 winter Polar Vortex resulted in historically high EAS prices, those market conditions were appropriately reflected without adjustment in the Annual Update process for the 2017-2021 Demand Curves, resulting in lower reference point prices for a portion of this first four-year DCR period under this new structure. No exception to the NYISO's tariff was made at that time to omit those high EAS prices as a one-off anomaly, and it would be unjust and unreasonable to do so now for a period with low EAS revenues. The Board should reject any further requests that its submission to FERC include a recommendation to propose a "one-time adjustment" to the Annual Update process.

III. THE BOARD SHOULD ADOPT STAFF'S AND THE CONSULTANTS' RECOMMENDATION THAT THE ZONE G DUTCHESS COUNTY PROXY PEAKING UNIT INCLUDE SCR EMISSIONS CONTROL TECHNOLOGY.

IPPNY strongly supports Staff's and the Market Monitoring Unit's ("MMU") concurrence with the Consultants' recommendation that the Zone G Dutchess County proxy peaking unit include SCR emissions control technology for the purpose of setting Net CONE. As Staff correctly acknowledges, a dual-fuel plant design has not been proposed without SCR emissions controls in any prior reset, and run-time emissions limitations for the proxy peaking unit (GE 7HA.02) when burning oil would permit annual operation of only approximately 260 hours or less for a unit located within the severe non-attainment areas within the Lower Hudson Valley. Its determination that such a severe limitation that is not practical for a resource needed to maintain reliability is sound.[9] It would be unreasonable to suggest that the proxy peaking unit should be designed to *limit* its run hours in lieu of installing SCR emissions control technology to comply with existing environmental regulations at the same time that NYISO studies recognize the heightened need for more flexible dispatchable resources to balance the higher penetration of intermittent resources on the system in the future. The NYISO is actively developing market products to value increased flexibility in operation of dispatchable resources to meet State public policy goals and there is every indication that additional emission restrictions may well be implemented before the State reaches its carbon-free end state in 2040.

Moreover, the Consultants and the MMU rightfully acknowledge that the decision to install SCR emissions controls goes beyond simple economic considerations. It is very likely that equipping a facility with the most state of the art emissions controls will be a prerequisite for any developer seeking local and State permits. As the MMU suggests, recent Article 10 siting processes suggest that a new plant in Zone G can expect intense local opposition and may regard proposing SCR technology as a necessity.[10] A key purpose of the Demand Curves is to provide market resources with the price signals needed to meet reliability requirements. Therefore, it is critical that the proxy unit include all costs that a developer would likely face. If the developer is highly unlikely to be able to build without including SCR emissions controls on the proxy peaking unit, the proxy peaking unit must include those assumptions because there is no alternative where SCR is not included. For the foregoing reasons, the Board should support

[9] Final Report at P 14.
[10] *See* MMU Comments on Independent Consultant Interim Final Draft ICAP Demand Curve Reset Report and NYISO Staff DCR Draft Recommendations at P 16 ("MMU Comments on Staff Draft Report"), available at https://www.nyiso.com/documents/20142/14526320/NYISO-Staff-Final-DCR-Recommendations.pdf/ed674d38-b08a-5287-925a-05dbdbe702fc.

NYISO's Staff's recommendation to include SCR emission control technology on the Zone G Dutchess County proxy peaking unit.

IV. THE BOARD SHOULD SUPPORT STAFF'S RECOMMENDATION TO UTILIZE A DUAL TGP Z4 (200L)/NIAGARA GAS HUB APPROACHIN THE NON-WINTER AND WINTER MONTHS, RESPECTIVELY, FOR PURPOSES OF CALCULATING NET EAS REVENUES FOR THE ZONE C PROXY PEAKING UNIT.

IPPNY supports Staff's recommendation to use a dual gas hub approach for purposes of calculating the Net EAS revenues for the Zone C proxy peaking unit as opposed to AGI's recommendation that TGP Z4 (200L) be the sole gas hub for Zone C. It would be unreasonable to select TGP Z4 (200L) for Zone C during the winter months because it does not meet the four selection criteria established by AGI: Market Dynamics; Liquidity; Geography; and Precedent. AGI defines Market Dynamics as:

> The gas index should reflect gas prices consistent with [Location Based Marginal Prices [("LBMPs")], recognizing that other factors such as transmission congestion also influence the frequency and level of spikes in LBMPs. Ideally, the gas index used in peaking plant net EAS revenues calculations would reflect a long-term equilibrium rather than short-run arbitrage opportunities created due to near-term or transitory natural gas system conditions"[11]

As Competitive Power Ventures ("CPV") demonstrated in its comments submitted in response to Staff's Draft Recommendations on August 24, 2020, TGP Z4 (200L) alone exhibits a poorer correlation between gas prices and LBMPs than does the current gas hub, TETCO M3, due to its geographic disconnect from New York State and the congestion costs that would be incurred transporting that gas to the Zone C proxy peaking unit. The correlation issue is largely

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[11] Final Consultants' Report at P 91.

driven by the deviation between TGP Z4 (200L) gas prices and Zone C LBMPs in the winter months. Addressing the Consultants' proposal in its comments on NYISO Staff's draft recommendations, the MMU confirmed that purchases of gas at TGP Z4 (200L) may not be readily accessible in the winter due to pipeline constraints, *i.e.*, that generators in Zone C cannot easily get transportation from TGP Z4 (200L) during winter months.[12] The MMU recommended, and Staff supports in its Final Recommendations, that designation of the Niagara gas hub during these periods of pipeline constraints, which occur between December and March, results in superior Market Dynamics than if TGP Z4 (200L) was used alone. Unless this issue is addressed, it will result in misalignment between gas costs and LBMPs. The Board should thus support Staff's Final Recommendation in this regard because it takes into account real-world limitations on the gas system in the form of congestion on TGP Z4 (200L).

V. THE BOARD SHOULD DIRECT STAFF TO USE A 15-YEAR AMORTIZATION PERIOD.

Staff's recommendation to reduce the amortization period from 20 to 17 years is right in principle but ultimately wrong as applied. The Climate Act, which mandates that the power sector be emissions-free by 2040, has a direct impact on the useful operating life of the reference unit. It is therefore reasonable to assume that the useful operating life of the selected proxy peaking unit will end in 2040. However, publicly available information demonstrates that Staff's and AGI's proposed 17-year amortization period is an unreasonable approximation of the

[12] MMU Comments on Staff Draft Report at PP 10-15.

number of years during which a new peaking unit could reasonably be expected to recover its capital costs.

As IPPNY advocated in both its July 1 Comments and its August 24 Comments, a 15-year amortization period is the only reasonable approximation of the amount of time the developer of a new peaking unit responding to the reference point prices for the 2021-2025 Demand Curves can expect to recover its capital costs. Staff's proposed 17-year amortization period wholly ignores the fact that no new fossil peaking plant similar to the proxy unit is under construction at this time or could be expected to reach commercial operation before the second half of the DCR period (2023-2025), at the earliest. Indeed, review of the NYISO's interconnection queue confirms the currently proposed amortization period is untenable. There are three fossil-fuel based projects in Class Year 2019 ("CY19") – the Danskammer project (#791), the Liberty Generating Alternative project (#668), and the Gowanus Gas Turbine Facility Repowering project (#778). When they entered CY19, the projects had estimated Commercial Operation Dates ("CODs") of October 2023; February 2024; and May 2024, respectively.[13] As is common with developers' COD estimates, these dates may be optimistic, particularly given current public and government sentiment towards fossil-fuel investment in New York State. For example, the Cricket Valley Energy Center and CPV Valley each took longer than 10 years to develop.

Assuming, arguendo, that each of these facilities proceeds and achieves its currently designated COD, they would have economic operating lives of 16.3, 15.9, and 15.7 years,

[13] See CY19 Status Update (January 7, 2020), available at https://www.nyiso.com/documents/20142/10150338/05_CY19%20Status%20Update_TPASJan072020_Draft.pdf/acbc5e0d-c4b1-74f5-718e-5a3c755a8eb6.

respectively, in compliance with the Climate Act's mandate. Thus, under what are likely the best-case scenarios, on average, and consistent with AGI's methodology of proposing a static operating life across the entire four-year DCR period (calculated as the average of the facility's remaining operating life in each year), the average operating life of the three facilities in CY19 is only 16 years.[14] Importantly, this 16-year period also presumes estimated CODs will hold in the face of permitting, construction and other delays that are common for electric generating projects in New York. Moreover, any developer of a fossil-fueled project subsequently entering a future CY in response to the new reference prices established in this DCR will likely have a COD no earlier than 2023 and very likely closer to 2025, making the currently recommended 17-year amortization period even less tenable for investors seeking to recoup their costs before 2040.

Even under these best-case circumstances, the proposed 17-year amortization period is insufficient for project developers to recover the capital costs of their projects. To be clear, IPPNY is not basing this position on what any one generator may or may not do. The amortization period should be durable throughout the reset period. Thus, considering probable construction timelines based on any proposed projects that could actually be developed during this DCR period, and taking into account risk to in-service dates, a reasonable amortization period for the fossil-fueled peaking plant can be no longer than 15 years.

The MMU and a number of other stakeholders suggest that the NYISO should not deviate from the historically assumed 20-year amortization period. They suggest that the owner of the proxy peaking plant will likely be able to retrofit the facility to run on alternative fuels, such as

[14] The commercial operating life was calculated by counting the number of years between May 1 of the Capability Year the unit reaches COD and January 1, 2040, consistent with Consultants calculations used to recommend a 17- year amortization period (see P 63 of Consultants' Draft Report).

hydrogen or renewable natural gas, that are presumed will comply with the Climate Act's emissions-free mandates, thereby retaining the value of the plant post 2040. These assertions put the cart before the horse. The MMU justifies its assertion by citing to studies conducted by AGI and the Brattle Group which conclude that prohibitively large amounts of renewable and battery resources would be needed to replace fossil fuel-fired generation after 2040, and, therefore, there is no reasonable basis for assuming that all existing dispatchable resources will retire. While it appears likely there will be a need for dispatchable generation on the system in 2040 based on what is known about technological advances at this time, there is simply no way of knowing which resources or technologies will be feasible, economically viable, or permitted by the State to meet the goals of the Climate Act, or whether the proxy peaking unit in each of the areas would ultimately be one of those dispatchable resources that continue to operate. Nor, equally importantly, can any cost for such retrofits reasonably be estimated at this time, as AGI repeatedly established during the stakeholder meetings. No party provided evidence to the contrary.

The MMU further cites to a statement by the developer of the proposed Danskammer gas-fired repowering project that the facility can transition to zero-emission hydrogen power "when the technology is available to transport and store hydrogen." The MMU and other stakeholders' assertions that a developer of the fossil fuel-fired proxy peaking plant will be able to retrofit the facility to run on an alternative fuel source are completely subjective and not based on evidence. It should be noted that conversion is likely to have significant costs, those costs are unknown at this time because this technology is not available, and none of the entities proposing longer amortization periods have included a reasonable quantification of those future costs in their proposals.

Investors will not finance projects today based on the possibility of retrofitting a facility at a later date with technology that does not currently exist and the costs for which cannot be known. Nor will an investor rely upon a fuel source that does not exist in the quantities, and at the prices, that would be necessary to reliably operate a peaking facility. Moreover, direct conversations between developers and equity investors demonstrate that lenders are unwilling to take this bet on a wing and a prayer and finance projects that cannot comply with the Climate Act beyond 2040. To the contrary, they are seeking to recoup their capital prior to 2040, the very basis for IPPNY's proposed 15-year amortization period.

VI. THE BOARD SHOULD DIRECT STAFF TO INCREASE THE RECOMMENDED ROE, AND EXPLICITLY ACCOUNT FOR THE COST OF FINANCIAL HEDGES IN THE COST OF THE PROXY UNIT.

The financial parameters recommended by AGI and supported by Staff that are used to calculate the Weighted Average Cost of Capital ("WACC") to a developer of the proxy peaking unit are flawed. They are too heavily benchmarked against corporate debt when the evidence of project development in New York demonstrates that investments have been, and are continuing to be, made utilizing project finance debt. In addition, the proposed WACC does not adequately reflect the risk of fossil-fuel based investment in New York, and ignores evidence that IPPNY and its members have provided demonstrating that lenders require developers to incur the upfront capital cost or ongoing financial carrying costs of energy margin hedges.

As reflected in the Final Consultants' Report, AGI determined the WACC inputs, in part, based on publicly available information from publicly traded IPPs (NRG Energy, Vistra Energy, Calpine, and Talen Energy) and independent assessments.[15] Specifically, AGI first evaluates the estimated ROE for two of these publicly traded IPPs (NRG and Vistra), which has averaged between 7.79% and 9.13% -- while acknowledging that, because these companies' business activities and portfolios of assets extend outside of merchant power generation, their ROE is "not necessarily comparable to the required [ROE] for a new peaking plant project in New York."[16] AGI next relies on the previous two net CONE studies of PJM and ISO-NE, which had ROEs that ranged from 12.8% to 13.8%.[17] Lastly, AGI considers estimates of the ROE for stand-alone project finance developments from several independent sources, which ranged as high as 20%.[18] Based on all of this information, AGI recommends an ROE of 13%, which it claims is a balance between the lower IPP value and higher project finance values.

The recommended ROE of 13% is too low. As IPPNY demonstrated in both its July 1 Comments and its August 24 Comments, AGI based its ROE recommendation too heavily on the average estimated ROE of publicly traded IPPs, which primarily invest in new projects utilizing balance sheet financing. AGI disregarded 20 years of evidence demonstrating that all new gas-fired power generation projects in New York have been financed utilizing non-recourse financing, *not* balance sheet financing.[19] There are any number of reasons why developers have

[15] Final Consultants' Report at PP 64-65.
[16] *Id.* at pp. 70-71.
[17] *Id.*
[18] *Id.* Notably, each of the studies cited by AGI report ROEs for stand-alone project finance that ranges from 15% to 22%.
[19] See IPPNY July 1 Comments at PP. 12-15. IPPNY utilized the IJGlobal Project Finance & Infrastructure Journal transactional database. The following gas-fired generators have been project financed since January 1, 2000: Cricket Valley Energy Center; CPV Valley; Bayonne Peaker Energy Center; Astoria Energy Phase I & Phase II; Rensselaer Combined Cycle Power Plant; and

chosen to finance their projects utilizing non-recourse financing over balance sheet financing in New York, but the fact remains that equally weighting the expected ROE of publicly traded IPPs and private-equity backers is an unreasonable balance given actual historic investments. Even in the case of corporate investment, the corporate cost of capital is the average for the corporation. AGI has acknowledged that the companies reviewed have a combination of merchant projects and projects backed by contracts. If a publicly traded company were to use balance sheet financing for a merchant facility, they would require a higher return than their corporate rate because the investment is riskier than their corporate portfolio.

Moreover, Staff's recommended ROE also is too low because it *underweights* the level of risk faced by developers of fossil generation in New York. Notably, neither PJM nor ISO-NE operates a market where a single state's public policies so directly increase the risk of investment in the region. While the multi-state nature of PJM and ISO-NE allows developers to locate supply within jurisdictions that present the least regulatory risk, a developer within the NYISO footprint cannot avail itself of similar risk mitigation tactics. New legislation and regulations already enacted in New York, such as the Climate Act, the Renewable Siting Act – which expedites the siting or renewable resources – and newly promulgated New York Department of Environmental Conservation ("DEC") rules (the "Peaker Rule"), to substantially restrict emissions from peaking units by 2023 and 2025, require a higher ROE to account for the additional risk faced by fossil investments in New York.[20]

Caithness Long Island Power Plant. Projects that were balance sheet financed were limited to acquisitions and additions to existing facilities.

[20] July 1 Comments at P 15, available at https://www.nyiso.com/documents/20142/13609298/IPPNY-Comments-on-DCR-Initial-Draft-Report-7-1-20.pdf/8c17b9d8-a0b4-587b-b857-f94582642637.

Indeed, could there be any question at all at this juncture the State's public policy direction, DEC erased it during this DCR process. Specifically, the DEC has proposed regulations for public comment to reduce greenhouse gas emissions statewide to 60% of 1990 levels by 2030 and to 15% by 2050 in compliance with the mandates of the Climate Act.[21] The NYISO should therefore more heavily weight the expected ROE for project financed projects by increasing the ROE to between 15% and 17%, which is squarely within the range of the expected ROE for private lenders and consistent with the ROE that would be expected of even publicly traded companies due to the outsized risk of investing in fossil-fuel infrastructure in New York.

Staff's acceptance of AGI's recommended WACC parameters is made more unreasonable by AGI's assertion that the parameters account for energy margin hedges that are common requirements of construction project financings without including any costs of securing those hedges. Since the 2016 DCR process, it has been the experience of IPPNY members that lenders have routinely required, in PJM, ISO-NE, and NYISO, energy margin hedging for all new merchant natural gas facilities through revenue puts which represent a considerable upfront funding requirement coinciding with the financial closing of the facility. Revenue puts establish a floor amount of energy-related revenue every month during the term of the financing, the cost of which can only be reflected in the upfront premium payment for the put option at financial close. Financial hedges are akin to an insurance policy that guarantees the lender it will receive a certain amount of revenue in the event that market revenues are insufficient to cover a borrower's debt payments. Lenders will *not* make capital available to a developer without a

[21] DEC Releases Proposed GHG Reduction Regulations to Implement Climate Leadership and Community Protection Act. Available at https://www.dec.ny.gov/press/121141.html

financial hedge, *especially* in New York where the absence of a forward capacity market significantly increases revenue uncertainty, which is a further reason why partial reliance on the financial parameters assumed in ISO-NE and PJM for purposes of determining accurate financial parameters in NYISO is misguided.

As the developers of the Cricket Valley Energy Center and the CPV Valley Energy Center have indicated to NYISO Staff, there is, in fact, a material cost of hedging instruments used in the financing and construction of those projects. These developers disclosed their hedging costs in their buyer-side market power mitigation ("BSM") filings submitted to the NYISO's internal Market Mitigation & Analysis department as part of the Class Year study process. This is a distinct expense that is separate and apart from the cost of capital determined through Staff's recommended WACC parameters.

The methods by which different technologies are financed in the power sector are fluid. What was an acceptable balance of considerations in a previous DCR does not guarantee that same balance is just and reasonable in the current or next DCR. Indeed, the periodic review process was incorporated in the Demand Curve structure from the outset to ensure technology advancement, system conditions, market factors and any other relevant changes were captured in each reset process. AGI and Staff have inexplicably ignored required hedging arrangements notwithstanding clear evidence demonstrating they are now a necessary precondition to secure financing of a merchant project in New York. Thus, the Board should direct Staff to revise the Final Report to account for the cost of hedging by reflecting the actual development costs incurred to construct the proxy unit. If hedging is not explicitly accounted for in development costs, the Board should direct Staff to increase the assumed Cost of Debt of 6.7% because the currently proposed Cost of Debt is far below the rate of return a lender would seek in order to make capital available without a hedge, which, as explained *supra*, is required by all lenders.

VII. THE BOARD SHOULD DIRECT STAFF TO INCREASE PIPELINE CONSTRUCTION AND NYC LAND LEASE COSTS BASED ON THE EVIDENCE PROVIDED.

A. PIPELINE CONSTRUCTION COSTS

Since IPPNY's initial comments were submitted on July 1, BMCD increased the proposed gas pipeline interconnection cost from $180k to $250k per inch diameter per mile for all Load Zones except Zone J. The $250k per inch diameter per mile recommendation is a mere 38% increase when IPPNY demonstrated that the costs of the most recently constructed gas lateral pipeline in New York, the CPV Valley Millennium Pipeline lateral, were roughly $511k per inch diameter per mile, more than 200% higher than BMCD's initial recommendation. IPPNY understands that the proposed $250k per inch diameter per mile cost represents a generalized estimate that applies to all Load Zones and acknowledges that project specific costs may be higher or lower depending on varying circumstances. However, to recommend a gas interconnection cost that is so clearly below actual costs incurred by a developer that responded to currently applicable siting requirements, such as a requirement to trench the entire length of the pipeline, is clearly unreasonable.

Moreover, in addition to evaluating the costs of the CPV interconnection, the BMCD cost recommendation is calculated based on the average of costs of five other recently constructed pipelines in or around New York: the National Fuel Gas Northern Access, the Constitution Pipeline, the PennEast Pipeline, the National Fuel Gas FM100, and the Bayonne Lateral Delivery projects. Of these projects, the Constitution Pipeline has been cancelled, the FM 100 is unconstructed, and the Northern Access and PennEast pipelines are both stalled 100+ mile long interstate pipelines with preliminary cost estimates that cannot be relied upon and, even if they could be, benefit from economies of scale and efficiencies that a lateral pipeline a fraction of the size would be unlikely to achieve.[22] The only pipeline evaluated by the Consultants that has actually been constructed and that shares characteristics similar to that of the proxy peaking unit lateral being evaluated is the Bayonne Lateral Delivery project, and that project was completed in 2012 before the current level of hostility towards fossil fuel infrastructure existed in New York.

As demonstrated in the comments of CPV Valley Energy Center submitted contemporaneously herewith, an analysis of completed gas lateral pipelines in the Northeast that more closely resemble the characteristics of the proxy peaking unit lateral, *i.e.*, are closer in length, indicates costs closer to $950k per inch diameter per mile, nearly quadruple the recommendation in the Final Report. Therefore, the Board should direct Staff to eliminate comparison cases that are irrelevant and revise its $250k per inch diameter per mile recommendation to reflect the magnitude of costs actually incurred by CPV during construction of the Millennium lateral, which is the only lateral pipeline that has been constructed in New York under current State regulations and in light of current public sentiment, or complete a new benchmarking analysis with an appropriate selection of gas lateral projects.

[22] Energy Information Administration Natural Gas Pipeline Projects Excel Spreadsheet (Accessed October 10, 2020), available at https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx.

B. NYC SITE LEASING COSTS

Another considerable discrepancy between the Consultants' and Staff's recommendations and real-world evidence presents itself in the Site Leasing Cost Assumptions for Zone J. In its July 1 and August 24 Comments, IPPNY demonstrated that the $270k/acre-year site leasing cost assumption was based on stale-data which was developed back in the 2010 DCR and simply escalated for inflation in each DCR period since then. Given such data is stale, IPPNY cited to recent appraisals provided by Eastern Generation ("Eastern") to BMCD which indicated that the value of land that is suitable for proxy peaking plant development in Queens and Brooklyn is roughly *double* the $270k/acre-year cost that is currently recommended.

The appraisals were conducted by three independent appraisers. It is important to appreciate not only the sources of the appraisals, but also their uses. Eastern is party to a 25-year easement granted by the NYS Department of State at the Narrows Generating Station located in Sunset Park, Brooklyn. This easement expires in 2024. The NYS Office of General Services ("OGS") required Eastern to contract with two local, independent appraisers – from a list provided by OGS – for the express purpose of determining how much NYS would *charge* Eastern to renew the easement. The original easement granted in 1999 cost $425k for a term of 25 years. After providing OGS the recent appraisals, Eastern was notified that a renewal for another 25 years would cost *$6.48 million.*[23] Obviously, this increase in proposed cost significantly exceeds any inflation metric.

[23] The notification from OGS is included herein as *Attachment A.*

Furthermore, Eastern conducted an independent appraisal of land adjacent to its Astoria Generating Station in Astoria, Queens. This land is owned by the New York Power Authority ("NYPA"). Eastern conducted this appraisal as it was responding to a Request for Proposals ("RFP") conducted by NYPA. The RFP invited bidders to express interest in leasing NYPA owned land for the express purpose of building a new, utility scale energy storage facility should the respondent be awarded a long-term contract from Con Edison and the New York State Energy Research and Development Authority ("NYSERDA"). Eastern used the independent appraisal to inform its lease offer. This offer was accepted by NYPA, contingent on Eastern being selected by Con Edison/NYSERDA to construct the ESR facility. Ultimately, Eastern was not selected to build an ESR facility. The rejection had nothing to do with the lease offer, which was acceptable to NYPA. The lease offer was $522k/acre-year or almost exactly double the $270k/acre-year proposed by the Consultants. Again, the $522k/acre-year (which would have been inflated over time) represents the amount Eastern *would have been willing to pay* to *construct a new generating facility in NYC*. This is exactly the data point which is germane to the exercise of calculating the costs of new entry in NYC.

In their August 10 presentation to stakeholders, the Consultants claimed to have considered market transactions, property tax values, stakeholder-provided feedback, and quoted values obtained through discussion with various property owners concerning the potential acquisition of land for similar use, and determined that the $270k/acre-year recommendation was within the observed range of values. Importantly, however, BMCD did not provide any details nor was BMCD able to confirm that the other properties they considered were in reasonable proximity to the necessary gas and electric interconnections to support a proxy peaking plant.

In its August 24 Comments, IPPNY requested that additional information be provided on the range of values that were observed by BMCD, as the only value known to stakeholders to date is the value of land that Eastern has offered and provided to the Consultants and NYISO, which, again, was more than 100% higher than BMCD's recommendation. No information has been provided. Without this additional information, it is impossible to determine whether BMCD is valuing land that is a viable option for power plant construction. Therefore, the Board should direct Staff to revise its Site Leasing Cost Assumptions upwards based on the facts and evidence provided by Eastern.

VIII. THE BOARD SHOULD DIRECT STAFF TO RETAIN IROQUOIS ZN2 AS THE GAS HUB FOR ZONE G ROCKLAND COUNTY AS OPPOSED TO TETCO M3.

AGI has not met its burden of demonstrating that designating TETCO M3 as the gas hub for the Zone G Rockland County proxy peaking unit is just and reasonable. Indeed, both AGI and NYISO Staff provided no independently developed analyses to support their recommendation in this regard. Nor could AGI do so. Evidence provided in the comments of GenOn, submitted to the Board contemporaneously herewith, demonstrates that the MMU used the wrong data set to analyze the system availability in support of selecting TETCO M3. When the correct data sets are used, it cannot be disputed that interruptible transportation service is unavailable in Zone G (Rockland) during peak operating conditions, the primary periods that peaking plants are required to operate for reliability. Therefore, taking AGI's four-part criteria discussed *infra* into account, IPPNY respectfully urges the NYISO Board to reject Staff's recommendation and continue to designate the existing gas hub, Iroquois Zn2, or, alternatively, the Algonquin City Gate, as the natural gas hub for the proxy peaking unit in Zone G.

In its 2017 DCR order, FERC found that the use of the multi-factor test used by the NYISO and the consultants to support their selection of natural gas hubs for each peaking plant location was consistent with the Services Tariff and enabled the NYISO to select valid gas hubs and provided transparency.[24] The multi-factor test included four criteria: Market Dynamics; Liquidity; Geography; and Precedent. For the current DCR, AGI and the NYISO once again rely on this multi-factor test for selecting the natural gas hubs that will be used to determine the natural gas prices for the individual Load Zones.[25]

During the 2016 DCR process, the NYISO argued that the market dynamics criterion was particularly important because natural gas hubs that are not correlated with electricity market dynamics and pricing outcomes may not accurately reflect the proxy peaking unit's actual supply costs. As a result, the net EAS revenues available to the proxy peaking plant will be significantly overstated, resulting in artificially lower reference price points for the ICAP Demand Curves that will not support the construction and retention of needed facilities for the long-term reliability of the system.[26] The NYISO further argued that it selected Iroquois Zn2 as the sole natural gas hub for Zone G because it was far better correlated than TETCO M3 to LBMPs and, therefore, was the most reflective of market dynamics in that Load Zone.[27] The NYISO also focused on the fact that Iroquois Zn2 had adequate levels of trading history and

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[24] Docket No. ER17-386, New York Independent System Operator, Inc., Proposed ICAP Demand Curves for the 2017/2018 Capability Year and Parameters for Annual Updates for Capability Years 2018/2019, 2019/2020 and 2020/2021 (Nov. 18, 2016), Exhibit D, Analysis Group, Inc. et al., Study to Establish New York Electricity Market ICAP Demand Curve Parameters ("2016 DCR Report") at PP 79-80.
[25] As established in the GenOn and CPV comments submitted on August 24, AGI failed to take into account relevant information concerning the gas market dynamics of gas supply that is transported through southeastern New York to southern New England. When all relevant facts are reviewed, the TETCO M3 gas hub clearly cannot meet the geography criterion.
[26] 2016 DCR Report at P 63.
[27] *Id.*

activity in comparison to alternatives proposed by protestors. Expressly finding that NYISO's Zone G determination, in particular, was just and reasonable, FERC determined the NYISO had reasonably weighed the options and agreed with the NYISO's assessment of the importance of the correlation of natural gas prices at the selected hubs with LBMPs for the relevant load zone and its emphasis on trading history and activity.[28]

While AGI has sought to depart from the FERC-approved Iroquois Zn2 for Zone G (Rockland) in this DCR process, its selection of TETCO M3 is not just and reasonable. For example, as established by GenOn, there is generally no interruptible transportation service on the Algonquin pipeline to deliver TETCO M3 gas to the proxy peaking unit during the peak summer and winter periods. Instead, gas flows to New England local distribution companies and utilities under firm transportation contracts, leaving no capacity available for interruptible transportation service. As further established by GenOn, AGI, the MMU, and Staff erroneously relied on data that seems to indicate there is interruptible transportation capacity on Algonquin available during the gas day at issue when there is definitively not. For the Demand Curve to provide sufficient revenues, the data inputs used must be both accurate and designed for the purpose identified. Here, the MMU has relied on timely nominations data but this data is developed in the first step of the gas day nominations process. As GenOn establishes, the only way to determine actual availability of interruptible transportation service which varies daily is to account for the ID3 nominations (published at day's end), no-notice reservations and IT flags. Compiling this data, GenOn effectively demonstrates that, since the CPV Valley plant began

[28] *N.Y. Indep. Sys. Operator, Inc.*, 156 FERC ¶ 61,039 (2016) at PP 80-81.

operations in late 2018, there has been essentially no interruptible transportation service available on the Algonquin pipeline. Indeed, in the peak winter months of December, January and February in the 2019/2020 winter, there were zero hours of availability across all three months.

While the proxy peaking unit's role is to provide reliability under stressed system conditions, it is exactly during these periods when TETCO M3 gas is the least likely to be available for the peaking plant's operations. Moreover, its correlation with LBMPs, while somewhat improved, remains poorer than other viable alternatives and it also cannot satisfy the precedent criterion. Applying AGI's four-part criteria, the TETCO M3 option is not a reasonable choice for Zone G (Rockland).

On the other hand, Iroquois Zn2 remains the reasonable gas hub selection consistent with the determinations made in the last reset process. It is well-correlated with LBMPs, accounts for the geography criterion, provides adequate trading history and activity and, because it was chosen in the last DCR, satisfies the precedent criterion.[29] Because AGI's and Staff's currently recommended gas hub will jeopardize reliability and is not just and reasonable for Zone G (Rockland), the Board must revise this recommendation. Based on the evidence provided, IPPNY respectfully urges the Board to maintain the current gas hub for Zones G (Rockland) in this DCR and direct its Staff to recalculate the 2021-2022 ICAP Demand Curve for the G-J Zone accordingly for submission to FERC in November.

[29] As reflected in the GenOn comments, the Algonquin pipeline produces better correlation and meets the geography criterion. Thus, it, too, is just and reasonable. However, if the Board wishes to give additional weight to the precedent criterion, the Iroquois Z2 gas hub remains a just and reasonable option that should be endorsed.

IX. CONCLUSION

For the foregoing reasons, IPPNY urges the NYISO Board to direct Staff to make the requested revisions to the Final Report to produce just and reasonable 2021-2022 ICAP Demand Curves and parameters and methodology to calculate just and reasonable Curves for 2022-2025. As the NYISO Board considers the matters raised herein, IPPNY remains available to provide further information or clarification and is committed to engage its members to support such efforts. Thank you for your ongoing consideration of these issues.

ATTACHMENT A

ANDREW M. CUOMO
Governor

ROANN M. DESTITO
Commissioner

July 13, 2020

Denise Pursley, Esq.
Nixon Peabody LLP
Affordable Housing and Real Estate Practice Group Leader
50 Jericho Quadrangle
Jericho, NY 11753

Dear Ms. Pursley, Esq:

Re: Astoria Generating Company, L.P.
Narrows Generating Station
Borough of Brooklyn, Kings County
New York Upper Bay
Our File No. LUW 02205
Easement Fee

We have received the final appraisal from both appraisal company, Goodman-Marks report and Jacques O. Tuchler & Associates, Inc. in regard to vacant land formerly underwater being used as an Industrial / Power Generating Plant. New York State Office of General Services (OGS) appraisal group has had time to review each report and has reconciled a value for the site. The OGS reviewers have conclude the evaluation criteria used in the Goodman-Marks report and Jacques O. Tuchler & Associates, Inc. report are sound, and their value conclusion is reasonable and supportable.

The value of lands now or formerly underwater is based, upon the value of the adjoining upland. The appraisal was done according to New York State Regulation 270-6.8, "State-owned land under water shall be appraised based upon the value of adjacent upland." That value is further depreciated in accordance with formulas established by OGS to reflect its decreased value, applied to reflect riparian and littoral rights and interest of the adjacent upland owner. Historically, a 50% discount has been applied to the estimated value of the adjacent upland. After which, for this calculation, it is further discounted an additional 75% for its limited easement term of 25-years (full term = 100 years.)

OGS opinion after reconciling the two reports using the aforementioned formula is as following:

Reviewed Value: $300.00 per square feet (psf) of buildable area X 172,884 psf of easement area =

$51,865,200

50% reduction for Littoral Interest = $51,865,200 X .50 = $25,932,600

Reduction for Limited Term Easement = $25,932,600 X 25% = $6,483,150

OGS Final Value Easement of 25 Year Term Easement for Subject Parcel: <u>$6,483,150</u>

Please enclose a check made payable to the "***Commissioner of General Services***" in the amount of $6,483,150.00 together with a copy of your Certificate of Insurance with our File No. LUW02205 on it. Please include your LUW File Number on the check as well as any future correspondence to us regarding this matter.

Please submit check and Certificate of Insurance to:

New York State Office of General Services
State Asset & Land Management
Attn: Frederick Roberts
Corning Tower, 39th Floor
Empire State Plaza
Albany, N.Y. 12242

Upon receipt of the aforementioned items in addition to the Certificate of Insurance, we will authorize the easement and send an executed copy to you for your records. The Certificate of Insurance must reference **LUW02205** or it cannot be accepted.

If you have any questions regarding your renewal, please do not hesitate to call myself at (518) 474-2195.

Thank you for your cooperation.

Sincerely,

Frederick Roberts
Real Estate Specialist
State Asset & Land Management