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To: New York Independent System Operator, Inc. ("NYISO")

From: Matthew Schwall, Director of Market Policy & Regulatory Affairs

Date: August 24, 2020

Re: **Comments on Proposed Installed Capacity Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Consultants' Interim Final Draft Report & NYISO Staff Draft Recommendations**

Independent Power Producers of New York, Inc. ("IPPNY")[1] submits the following Comments on NYISO Staff's Draft Recommendations for the Installed Capacity ("ICAP") Demand Curves for the 2021/2022 through 2024/2025 Capability Years as informed by the Interim Final Draft Report prepared by Analysis Group Inc. ("AGI") and Burns & McDonnell ("BMCD") (collectively, the "Consultants") for the instant Demand Curve Reset ("DCR") process.

On July 1, IPPNY submitted extensive comments in response to the Consultants' Initial Draft Report (the "July 1 Comments"). Many of the concerns that IPPNY had with the Consultants' recommendations remain and have now been adopted by the NYISO, including the Consultants' recommended amortization period, financial parameters, gas hubs for Zone C and Zone G (Rockland), net energy and ancillary services ("EAS") revenue model, peaking

[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.

technology costs, and the decision to use Level of Excess Adjustment Factors ("LOE-AFs") that do not include the known retirements of peaking plants in New York City resulting from the Department of Environmental Conservation's ("DEC") NOx Limits Rule for Simple Cycle and Regenerative Combustion Turbines (the "Peaker Rule") except those limited plants that have been identified by the NYISO as triggering a reliability need. IPPNY also commented on the Consultants' initial recommendation not to include Selective Catalytic Emissions control technology on the Zone G Dutchess County peaking unit, which the Consultant and NYISO have since agreed should be included. IPPNY supports this decision for all of the reasons expressed in the July 1 Comments, which are not repeated here.

As IPPNY noted in its initial comments, the reliability analyses recently issued by both the NYISO and Con Edison demonstrate that the State's public policy initiatives will drive significant reliability needs on the New York system by 2023, *i.e.*, during *this* DCR period. Reference point prices must be adequate to ensure the system maintains sufficient new and retains sufficient existing dispatchable resources to address these needs and provide the necessary resource 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 and further heightened by the enactment of the Climate Leadership and Community Protection Act (the "Climate Act") in the intervening period. Aspects of the Interim Final Draft Report, however, rest on flawed assumptions and are materially deficient, and thus, are not just and reasonable because they will not produce the price signals needed to support this investment. IPPNY thus urges the NYISO to correct these errors in its Final Recommendations as established herein.

A. <u>Modifications to the Draft Report Are Required to Accurately Reflect the Gross Cost of New Entry ("CONE") of the Fossil-Fueled Proxy Peaking Unit in All Zones.</u>

The Consultants recommend, and the NYISO correctly supports, that the Zone G Dutchess County proxy unit must include Selective Catalytic Emissions control technology and that no one-time adjustments can be made to exclude any energy and ancillary services market prices for the period September 1, 2019 through August 31, 2020 as a result of the COVID-19 pandemic. However, the Consultants' proposed Demand Curve parameters continue to significantly understate the Gross CONE of the fossil-fueled proxy peaking technology by not adequately accounting for real world evidence or capturing the risks associated with developing a fossil-fueled peaking unit in New York State. The NYISO must reconsider its support of the following recommendations.

i. <u>Amortization</u>

The basis of AGI's recommendation to reduce the amortization period from 20 to 17 years is right in principle but ultimately wrong as applied. It is reasonable to assume that the useful operating life of the selected proxy peaking unit will end in 2040 when the Climate Act mandates that the power sector be emissions free. However, IPPNY maintains that the Consultants' proposed 17-year amortization period is an unreasonable approximation of the number of years during which a new peaking unit could reasonably be expected to recover its capital costs given information that is publicly available.

As IPPNY advocated in its July 1 Comments, a 15-year amortization period is the only reasonable approximation of the amount of time a new peaking unit responding to the reference prices for the 2021-2025 Demand Curves can expect to recover its capital costs. The Consultants' proposed 17-year amortization period wholly ignores the fact that no new fossil peaking plant similar to the proxy unit is under construction or could be expected to reach commercial operation until the second half of the DCR period (2023-2025), at the earliest. Indeed, review of the NYISO's interconnection queue confirms AGI's 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).[2] The projects have estimated Commercial Operation Dates ("CODs") of October 2023; February 2024; and May 2024, respectively.

Assuming, *arguendo*, that each of these facilities proceeds and achieves its intended COD, they would have economic operating lives of 16.3, 15.9, and 15.7 years, respectively, in compliance with the Climate Act's mandate.[3] Thus, under what are likely the best case scenarios, on average, and consistent with AGI's methodology for proposing that 17 years is the average operating life across the four-year DCR period, the average operating life of the three facilities in CY19 is only 16 years. And, any developer of a fossil-fueled project subsequently entering a future CY is likely to have a COD later than those of the three CY19 projects, making the Consultants' approach even less tenable.

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. 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,

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[2] *See* CY19 Status Update (January 7, 2020), available at https://www.nyiso.com/documents/20142/10150338/05_CY19%20Status%20Update_TPAS-Jan072020_Draft.pdf/acbc5e0d-c4b1-74f5-718e-5a3c755a8eb6

[3] 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 Draft Report).

IPPNY is not basing this position on what any one generator may or may not do. However, if no generator can achieve a defined parameter, the parameter itself cannot be considered reasonable. That is the case here. Thus, considering probable construction timelines based on *any* proposed projects that could actually be developed during this DCR period, and taking into account some potential for delays to be faced, a reasonable amortization period for the fossil-fueled peaking plant can be no longer than 15 years.

The NYISO's Market Monitoring Unit ("MMU"), Potomac Economics, 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 hydrogen or renewable natural gas, that are presumed to comply with the Climate Act's emissions free mandates, thereby retaining the value of the plant post 2040. The MMU justifies this 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, concludes that there is no reasonable basis for assuming that all existing dispatchable resources will retire.[4] While it is true that there will be a need for dispatchable generation on the system in 2040, 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. Nor, equally importantly, can any cost for such retrofits reasonably be estimated at this time as AGI repeatedly established during the stakeholder meetings.

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[4] MMU Comments on Independent Consultant Initial Draft ICAP Demand Curve Reset Report and forthcoming draft NYISO Staff DCR Recommendations, at P. 6. Available at https://www.nyiso.com/documents/20142/13609298/MMU-2020-DCR-Draft-Report-Comments.pdf/d31ba142-5af8-4b04-af51-1a275682a962

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 (emphasis added)."[5] 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 those future costs in their proposal. 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, and so are seeking to recoup their capital prior to 2040.

ii. **Weighted Average Cost of Capital ("WACC")**

AGI continues to recommend WACC parameters that 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, do not adequately reflect the risk of fossil-fuel based investment in New York, and do not take into account the upfront capital cost or ongoing financial carrying costs of energy margin hedges required by lenders. The NYISO must reconsider its decision to support without modification

[5] *Id*.

AGI's proposed financial parameters. Even in the case of corporate investment, the corporate cost of capital is the average for the corporation and AGI has acknowledged that the companies reviewed have a combination of merchant projects and projects backed by contracts. These companies would not consider investing in a future merchant facility based on being economic at their corporate debt costs because the merchant generator is riskier than their current respective portfolios. The NYISO must reconsider its decision to support without modification the Consultants' proposed financial parameters.

The assumed Return on Equity ("ROE") of 13% is too low. As IPPNY demonstrated in its July 1 Comments, AGI basis their ROE recommendation too heavily on the average estimated ROE of publicly traded IPPs, which primarily invest utilizing balance sheet financing, when 20 years of evidence demonstrates that all new gas-fired power generation projects in New York have been financed utilizing non-recourse finance, *not* balance sheet financing.[6] 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. There are any number of reasons why developers have 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 historic investments. 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.

AGI's proposed ROE is also too low because it *underweights* the level of risk faced by developers of fossil generation in New York. As explained in the IPPNY July 1 Comments, new

[6] See IPPNY July 1 Comments at PP. 12-15.

legislation and regulations already enacted, such as the Climate Act, the Renewable Siting Act and the Peaker Rule, require a higher ROE to account for the additional risk faced by fossil investments in New York. Moreover, since IPPNY's July 1 Comments were submitted, the DEC has proposed for public comment regulations 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.[7]

AGI's proposed WACC parameters are made more unreasonable by AGI's assertion that they account for energy margin hedges that are common requirements of construction project financings without including any costs of securing those hedges. Lenders have recently required 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, as explained in more detail in the comments of Danskammer Energy, LLC (notably, a developer actively seeking to finance a project that utilizes fossil-fuel technology) submitted contemporaneously with these comments.[8] 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. The Consultants proposed WACC is too low to have adequately accounted for these hedges in the assumed upfront financial closing costs of the peaking technology. As reflected in the NYISO's buyer-side market power mitigation ("BSM") analysis of recently developed projects, e.g. Cricket Valley Energy Center and the Valley Energy Center, there is, in fact, a material cost of hedging instruments used in the financing and construction of those projects. The methods by which

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

[8] Hereinafter referred to as the "Danskammer Comments."

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. Ineed, 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. AGI has 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. The NYISO must thus account for the cost of hedging, by reflecting it in the upfront closings costs to construct the proxy unit, in its Final Recommendations.

iii. **<u>Capital Cost Assumptions</u>**

The Consultants divide the capital costs of the proxy unit into EPC (engineer, procure, construct) and Non-EPC (owner's costs) costs. As a starting point, the Consultants have not provided a sufficient line item breakout of the information and individual cost components used to develop the assumed EPC costs consistent with the level of detail and nature of information provided in past DCR processes, which has been requested multiple times, for NYISO stakeholders to evaluate. Therefore, IPPNY cannot provide detailed feedback on the reasonableness of the EPC cost recommendations at this time, and requests that a detailed breakout of EPC costs be provided by Friday, August 28, and that stakeholders be given until Wednesday, September 2, to submit supplemental comments on this point. The Consultants also have not provided sufficient justification for why arguments and evidence presented by commenters in response to the initial draft recommendations have been implicitly dismissed or ignored in issuing the Final Report.

Based on the limited information that is available, it is readily apparent that the Consultants are grossly underestimating the assumed Owner's Cost Allowances for the *1x0 GE 7HA.02,* which are provided by line item in Appendix A to the Interim Final Draft Report.[9] The Consultants recommend Owner's Cost Allowances line items for Owner's Project Development, and Permitting and Licensing Fees in total across all Load Zones range from $1.37M to $1.78M. As is explained in detail in the Danskammer Comments, Danskammer, which is actively navigating the New York State Article 10 siting process, has already incurred development, permitting and licensing costs that exceed $8.6M and are expected to total $9.8M by completion. While it is true that the costs embedded in the DCR process calculations are intended to be for a generic facility, the level of costs assumed strain credulity when they are a small fraction of costs demonstrated to be incurred in practice. Indeed, Article 10 intervenor funding requirements alone which would apply to the proxy peaking plant cost $600,000, which is more than half of the Consultants' $1M assumption for permitting and licensing fees. Applying the Consultants' rational, participating in the Article 10 process is thus remarkably somehow more costly for intervenors than the project sponsor itself.

Assuming that the two aforementioned line items are the only cost allowances intended to account for completing the Article 10 process, the Consultants' recommended cost allowances for Zone G are just 16% of Danskammer's development costs to date and 14% of their projected total development costs, which is a staggering discrepancy even after acknowledging or accounting for the difference in technology and circumstance from the proxy peaking technology. Even though many of the Owner's Cost Allowances cannot conceivably be

[9] Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2020 through 2024/2025 Capability Years – Interim Final Draft Report, at P. 28. Available at https://www.nyiso.com/documents/20142/14404876/Analysis%20Group%20Appendix%20A%20-%20Unit%20Specifications.pdf/c44cf7d4-1a83-4704-7abd-b774879276f8

considered to be permitting costs, assuming, *arguendo*, that 50% of the costs for the Owner's Operational Personnel Prior to COD, Owner's Engineer, Owner's Project Management, and Owner's Legal Costs line items, in addition to the total costs for the Owner's Project Development and Permitting and Licensing Fees line items, are intended to account for the costs of navigating the Article 10 permitting an licensing process, the total line item cost of $3.165M (outside of Zones J and K) would still be 37% of Danskammer's costs to date and 33% of expected total costs at completion.[10] The NYISO must significantly increase the Owner's Cost Allowances for Owner's Project Development, Permitting and Licensing, or explain how the current recommendations are reasonable in light of the information provided by Danskammer and the development cost data submitted by both CPV and Cricket Valley in compliance with the NYISO's BSM requirements.

Beyond the direct comparison to actual investments made by developers, BMCD's owner's cost recommendations are, in most cases, half that of the owner's cost recommendations made during the 2016 DCR process. The Consultants have not provided explanation for why the change in proxy peaking technology has resulted in owner's costs that vary so greatly from the last DCR, especially when every indication is that siting and permitting a fossil-fueled peaking facility has become riskier and more costly in New York. For example, during the 2016 DCR process, AGI and Lummus Consultants International, Inc. ("Lummus") recommended Zone G owner's development costs of approximately $6.4M, whereas BMCD recommends owner's development costs of just $370k.[11] Lummus recommended permitting and legal costs of more

[10] The specific line items include: Owner's Operational Personnel Prior to COD ($220,000) + Owner's Engineer ($510,000) + Owner's Project Management ($565,000) + Owner's Legal Costs ($500,000) + Owner's Project Development ($370,000) + Permitting and Licensing Fees ($1,000,000).

[11] Study to Establish New York Electricity Market ICAP Demand Curve Parameters (September 13, 2016), at P. 112 Available at

than \$2.1M each, whereas BMCD has recommended permitting and legal costs of just \$1M each. Lummus recommended project management costs of \$3.19M whereas BMCD recommends project management costs of \$1.3M. Notably, BMCD does not even account for the cost of financing fees in its recommendations when Lummus assumed \$4.2M in financing fees. In almost every single case, the recommended owner's costs of the proxy peaking unit for the 2021-2025 DCR are a fraction of the assumed costs in the last DCR, with absolutely zero justification from BMCD. The NYISO must increase the assumed owner's costs across the board in its Final Recommendations or provide a justification for why the 2020 DCR owner's costs vary so dramatically from those assumed for the 2017-2021 Demand Curves.

Since IPPNY's initial comments were submitted on July 1, BMCD have increased the proposed gas pipeline interconnection cost from \$180k per inch diameter per mile to \$250k for all Load Zones except Zone J. The \$250k recommendation is a mere 38% increase when IPPNY demonstrated that the costs of the CPV Valley interconnection, which is the most recently constructed gas lateral pipeline in New York, were more than 200% higher than BMCD's initial recommendation.[12] IPPNY understands that the proposed \$250k cost represents a generalized estimate that applies to all Load Zones and that project specific costs may be higher or lower depending on varying circumstances, but 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.

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https://www.nyiso.com/documents/20142/1391705/Analysis%20Group%20NYISO%20DCR%20Final%20Report%20-%209_13_2016%20-%20Clean.pdf/55a04f80-0a62-9006-78a0-9fdaa282cfc2

[12] IPPNY July 1 Comments at P. 22.

Another considerable discrepancy between the Consultants' recommendations and real-world evidence presents itself in the Site Leasing Cost Assumptions for Zone J. In its July 1 Comments, IPPNY demonstrated that the $270k/acre-year land lease cost assumption was based on stale-data first developed during the 2010 DCR and escalated for inflation in each DCR period since then. Given such data is stale, IPPNY cited to appraisals provided by Eastern Generation to BMCD which indicated that the value of land that is suitable for proxy peaking plant development in Queens and Brooklyn is more than double the $270k/acre cost that the Consultants recommend. The appraisals were conducted by three independent entities pre-selected by New York City for the purposes of determining lease costs Eastern Generation would pay for land at two different locations for prospective power projects, i.e., Eastern Generation would prefer the appraisals to return a lower value. 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 in the potential acquisition of land for similar use, and determined that the $270k/acre-year recommendation was within the observed range of values.[13] BMCD did not provide any details nor was BMCD able to confirm these properties were in reasonable proximity to the necessary gas and electric interconnections to support a proxy peaking plant. IPPNY requests 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 Generation has offered in verbal comments and provided to the Consultants and NYISO, which, again, was more than 100% higher than BMCD's recommendation. Without additional

[13] NYISO 2019/2020 ICAP Demand Curve Reset: Updates for Interim Final Report, (August 10, 2020), at P. 6. Available at https://www.nyiso.com/documents/20142/14404876/Presentation%20Analysis%20Group%20Interim%20Final%20Demand%20Curve%20Reset%20Report.pdf/1c3584df-7157-32d3-f250-30bb25aa9f99

information, it is impossible to determine whether BMCD is considering the value of land viable for power plant construction.

iv. **Gas Hubs**

AGI has not met its burden of demonstrating that designating TGP Z4 200L and TETCO M3 as the gas hubs for the Zone C and Zone G Rockland County proxy peaking plants is just and reasonable. Nor could AGI do so. Evidence provided in the comments of CPV Valley LLC and GenOn, submitted contemporaneously herewith, demonstrates that the selection of these hubs fails the geography criterion, these hubs are not viable options particularly given the level of the transportation adders proposed, and they remain a poor selection under the market dynamics criterion. Taking AGI's four-part criteria into account measured against the potential options, the current gas hubs for Zone C and Zone G, TETCO M3 and Iroquois Zn2, respectively, continue to be a just and reasonable option and should be used for purposes of setting the 2021-2025 Demand Curves. Thus, IPPNY respectfully urges NYISO Staff to change these gas hubs and recalculate the 2021-2022 Demand Curves for the G-J Zone and the NYCA in its Final Recommendations accordingly.

In its 2017 DCR order, the Federal Energy Regulatory Commission ("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, enabled the NYISO to select valid gas hubs and provided transparency.[14] The multi-factor test included four categories: 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

[14] 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 at PP 79-80.

natural gas hubs that will be used to determine the natural gas prices for the individual Load Zones.[15]

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 plant'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 do not provide adequate price signals regarding the value of capacity.[16] 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.[17] The NYISO also focused on the fact that Iroquois Zn2 had adequate levels of trading history and activity in comparison to alternatives proposed by protestors. FERC found 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.[18]

While AGI has sought to depart from these two hubs in this DCR process, its selections are not just and reasonable. For example, as established by both GenOn and CPV, TETCO M3 gas delivered across the Algonquin lines is generally not available to New York parties. Instead,

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[15] However, AGI also specifies in its Final Report that it has "updated" the "methodology" it used to address the geography criterion. (*See* Final Report at n.81. As established in the GenOn and CPV comments submitted contemporaneously herewith, 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.

[16] *Id*. at P 63.

[17] *Id*.

[18] *Id*. at PP 80-81.

it flows to New England local distribution companies and utilities under firm transportation contracts. While the proxy peaking plant'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 its use. Moreover, its correlation with LBMPs 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, both TETCO M3 and Iroquois Zn2 remain the reasonable gas hub selection. They are well-correlated with LBMPs in their respective zones, meet the geography criterion, provide adequate trading history and activity and, because they were chosen in the last DCR, satisfy the precedent criterion.[19] Because AGI's and NYISO's currently recommended gas hubs are not reasonable for Zones C and G (Rockland), the NYISO must revise this recommendation. Based on the evidence provided, IPPNY respectfully urges the NYISO to maintain the current gas hubs for Zones C and G (Rockland) in this DCR and recalculate the Demand Curves for the G-J Zone and the NYCA in its Final Recommendations accordingly.

B. The Net EAS Revenue Model Developed Overstates Expected EAS Revenues Due to a Modeling Error and Must be Corrected.

IPPNY shares the concerns expressed by TigerGenco, LLC, the owner of the Bayonne Energy Center peaking plant, in its comments submitted contemporaneously herewith.[20] In its July 1 Comments, IPPNY expressed concern with AGI's EAS revenue model because it appeared to be overstating the revenues that generators could expect to earn in the energy market, therefore unjustifiably reducing the Demand Curve reference point prices. In response

[19] 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 NYISO Staff wishes to give additional weight to the precedent criterion, the Iroquois Z2 gas hub remains a just and reasonable option that should be endorsed.
[20] Hereinafter referred to as "Bayonne."

to these concerns and repeated requests that AGI perform benchmarking to confirm its revenue figures fell within a reasonable range of accuracy, AGI has simply responded that its expectation is that the model should net out underestimations in certain hours against overestimations in others. Since IPPNY's comments were submitted, Bayonne benchmarked the Consultant's EAS revenue model against its own revenues over the three-year historic period being evaluated by the Consultants and found that the model is, in fact, significantly overstating revenues as a result of an incorrect representation of the cost of gas over weekend periods.

As a result of their benchmarking analysis, Bayonne found that the model is assuming that a generator can burn gas over the weekend at the price quoted for Friday. This is a misrepresentation of how gas trading works. The price over the weekend is included in the posted price for the first trading day *after* the weekend which represents a strip of gas purchases. On a normal two-day weekend, the Monday quoted price is the price of gas for Saturday through Monday. On a holiday weekend that is celebrated on a Monday such as Martin Luther King weekend, the Tuesday price is the price of gas for Saturday through Tuesday. Bayonne's benchmarking analysis further confirmed that this error significantly contributed to the overstated Net EAS revenue estimates with the driving factor being weekends where the Friday gas price was substantially below the price that would apply for the weekend. In effect, the model was making two separate, but compounding, errors by assuming LBMPs that were consistent with higher gas costs over the weekends while also assuming that the generator could purchase the cheaper Friday gas cost for its operations over the weekend.

To correct these errors and align the model to more accurately reflect historic market data, Bayonne utilized the natural gas spot prices from S&P Global Market Intelligence for the next trading day after the holiday weekend (e.g., Tuesday), because the natural gas price reported on the next trading day after a weekend *is* the actual natural gas price for the entire weekend strip, rather than a one-day price, as the Friday price represents. The correction resulted in a far smaller divergence between the AGI's model results and Bayonne's actual results. These natural gas spot prices must be incorporated into the Net EAS revenue model as Bayonne has proposed to correct for the model's current substantial overstatement of expected revenues.

C. <u>The NYISO Must Utilize LOE-AFs That Reflect the Known Resource Retirements Resulting from DEC's Peaker Rule to Effectively Align with the Assumptions Used, and the Approach Taken, in the NYISO's Comprehensive Planning Processes and Meet the System's Resource Adequacy Needs.</u>

In the July 1 Comments, IPPNY requested that the LOE-AFs be updated to include all of the known retirements that were included in the NYISO's 2020 Reliability Needs Assessment ("RNA") so that the costs and revenue estimates used in setting the 2021-2025 Demand Curves would reflect the most recent information defining actual system conditions at the minimum ICAP requirements. AGI updated its recommendations to include some of the supply changes that were included in the RNA but nevertheless chose to ignore the market exit of peaking units responding to the statutory mandates established in DEC's Peaker Rule.

According to the 2020 RNA, the compliance plans submitted by the owners of these facilities confirm that there are a number of peaking units that will retire in, or offer only non-Ozone season capacity by, 2023, primarily in Zone J. The 2020 RNA studies confirm that a small portion of the total MWs to be retired would cause an immediate 110 MW reliability need in the Astoria East/Corona load pocket which rises to 180 MW by 2030 due to projected load growth.[21] In its August 10 presentation to the ICAP Working Group, the NYISO explained the

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[21] *2020 RNA Preliminary ("1st Pass") Reliability Needs*, NYISO (June 19, 2020) ("NYISO 2020 RNA Preliminary 1st Pass"), at P. 20. Available at

differences between its RNA study, Congestion Assessment and Resource Integration Study, and the Installed Reserve Margin ("IRM") study, and suggested that the treatment of supply resources in the LOE-AF study most closely resembles the treatment of resources in the IRM study.[22] In the IRM study, all units that are expected to retire within the study period are removed from the model. Units that are needed to meet reliability needs will have been identified in the short term assessment of reliability ("STAR") or RNA, both of which are conducted by the NYISO with input on local system considerations from the affected transmission owners. In this case, the NYISO has just completed an RNA and STAR analysis and found that all of the NYC peakers projected to retire in 2023 except those required to meet a 110 MW need in the Astoria load pocket can retire. For the NYISO's statement to be true that the LOE-AF study most closely resembles the treatment of resources in the IRM study, projected retiring or unavailable units over the LOE-AF study period must be removed from the model. In other words, the known peaker unit retirements and seasonally limited capacity must be removed from the LOE-AF model and only the minimum number of units needed to meet the 110 MW reliability need identified in the 2020 RNA should be retained. The NYISO must be objective and consistent in the application of its inclusion rules between its planning studies, regardless of the price impact.[23]

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https://www.nyiso.com/documents/20142/13200831/02%202020RNA_1stPassRN.pdf/8a0de336-bd24-1260-dc4b-5df58cdb049

[22] 2021-2025 ICAP Demand Curve Reset: NYISO Staff Draft Recommendations (August 10, 2020), at PP 11-12. Available at https://www.nyiso.com/documents/20142/14404876/2019-2020%20NYISO%20Staff%20Draft%20Recommendations%2008102020%20ICAPWG%20Final.pdf/17113790-92b9-f12f-1711-d171f889b166

[23] It again bears note that the NYISO Staff aggressively pursued Manual revisions before the impending start of the 2020 RNA to ensure that it could more effectively account for the decisions set forth by owners in their respective Peaker Rule compliance plans. Ignoring those changes here undercuts those efforts and ensures inconsistencies in the manner in which resources are modeled which, in turn, breeds uncertainty in market pricing.

A further reason the NYISO gives for not including the Peaker Rule retiring units is that only four months of market prices capturing the retirements would be used in the Net EAS revenue model, and that it doesn't believe accounting for the retirements in the LOE-AF study for the entire reset period would be "fair." This conclusion is inconsistent with the process for setting the LOE-AF – a process that by design is forward looking over the entire DCR period. It is not appropriate for the NYISO to selectively choose not to represent these retirements – and the associated market price impacts – which are directed by state law. It is no more unfair to model the peaker retirements impact for 2023 than it is to model any other assumptions for 2023 and 2024.

The NYISO treatment of assuming the peaking units will continue to operate when determining the LOE-AF is also inconsistent with its assumptions in the BSM analysis. With the approval of the Renewable Exemption Cap compliance filing, the NYISO will grant BSM exemptions for renewable resources based on known regulatory retirements. The NYISO's filing letter stated that it will incorporate the expected peaker retirements to comply with the Peaker Rule into the BSM evaluation. The NYISO also stated that the BSM evaluation would account for seasonal shutdowns of peaking units. The LOE-AF must also account for these peaking unit retirements and seasonal shutdowns to assure that it does not produce and rely on a LOE-AF that has been artificially inflated.

D. Conclusion

For the foregoing reasons, IPPNY urges NYISO Staff to make the corrections, provide the additional information identified herein and revise its Final Recommendations accordingly to produce just and reasonable Demand Curves for 2021-2025. As the NYISO 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.

Respectfully submitted,

/s/

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