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Via Email to mseibert@nyiso.com and 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 CPV Valley, LLC on the NYISO Proposed 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 the comments of CPV Valley, LLC to the NYISO Board of Directors on the *NYISO Staff's Proposed NYISO Installed Capacity Demand Curves for Capability Years 2021/2022 through 2024/2025*.

Additionally, CPV respectfully requests the opportunity to engage in oral arguments before the NYISO Board of Directors on the issues addressed in the enclosed submission.

Respectfully submitted,

Thomas Rumsey
Thomas Rumsey
Senior Vice President, Regulatory and External Affairs

Comments of CPV Valley, LLC on the NYISO Staff Final Recommendations for the 2021-2025 ICAP Demand Curves

CPV Valley, LLC ("CPV") appreciates the opportunity to provide written comments to the NYISO Board of Directors ("NYISO Board") on the recommended demand curve reset parameters. CPV's comments are the culmination of positions that CPV has expressed in written comments, stakeholder meetings, and discussions with the NYISO and its consultants, Analysis Group ("AG") and Burns & McDonnell.

CPV Valley, LLC is the owner and operator of the 760 MW combined cycle power plant in Orange County, New York, which is adjacent to Rockland County and within the G-J Locality. The facility was developed over 2007 to 2015 and was constructed from 2015 to 2018. CPV's experience with this facility – through development, construction, and continued operations and management – bears relevance on several critical assumptions of this demand curve reset.

The NYISO's recommended demand curve parameters materially understate the net cost of new entry for the reference plant. CPV urges the NYISO Board to direct NYISO staff to correct three deficiencies:

1. Gas Lateral Cost – the assumed cost of $20 million ($250,000 per inch-mile) is significantly less than the actual costs experienced by CPV. It is critical to accurately determine the average cost per inch-mile. To do so, one must benchmark other gas lateral projects to get accurate data. AG erroneously benchmarked interstate pipelines of over 100 miles in length that enjoy very different economies of scale from power plant laterals. The NYISO Board should direct NYISO staff to redo the estimation with pipelines that are representative of power plant laterals. CPV estimates an average gas lateral cost of $950,000 per inch-mile based on relevant data points.

2. Rockland County Gas Hub – the NYISO has erred in choosing TETCO M3. TETCO M3 is inferior across all four selection criteria. Most notably, it is currently impossible to source gas in Rockland County at the TETCO M3 price plus the $0.27/MMBtu embedded cost assumption, which excludes transportation and availability disruptions due to the likelihood that any transportation attained would be on an interruptible basis. Gas access will be interrupted on the most volatile market days, which will hinder the assumed net EAS revenues earned by the reference plant.
3. Owner's Costs – the NYISO and AG have erred in excluding at least $5 million in financing fees and at least $15 million in development costs. NYISO and AG have defended the approach by stating that these costs are included within other cost categories, namely AFUDC/IDC, gas lateral costs, and contingency. However, financing fees and development costs are unique costs that cannot be construed as included within these categories.

1. Gas Lateral Cost

AG assumed a $20 million capital cost for the gas lateral for zones C, F, and G, plus $3.5 million for metering and regulation equipment. The $20 million equates to $250,000 per inch per mile and is a fraction of the costs of three power plant laterals with which CPV has recent, firsthand experience:

- CPV Valley lateral – $60,900,000 or $522,000 per inch-mile
- CPV Middlesex expansion – $53,000,000 or $1,890,000 per inch-mile
- CPV Woodbridge lateral – $32,000,000 or $751,000 per inch mile

To estimate the $250,000/inch-mile cost, AG analyzed six gas pipeline projects in the Northeast. From this list, AG discarded the highest and lowest-cost projects, and averaged the remaining four costs, arriving at $250,000/inch-mile. The NYISO identified the six projects at the request of stakeholders.[1] Figure 1 summarizes the six projects, drawing on data from the EIA and the pipeline operators' FERC filings.

Figure 1. Gas Lateral Costs

No.	Project	Length (Miles)	Diameter (inches)	Cost ($MM)	Cost ($/in-mi)	2021 Dollars ($/in-mi)	State(s)	Status
1	Constitution Pipeline	121	30	$683	$188,154	$191,917	NY, PA	Cancelled
2	PennEast Pipeline Co	118	24	$1,000	$353,107	$360,169	NJ, PA	On Hold
3	Northern Access Project	101	24	$455	$187,706	$191,460	NY, PA	On Hold
4	FM 100 Project	31	20	$279	$445,671	$445,671	PA	Anticipated 2021
5	CPV Valley Lateral	8	16	$61	$491,764	$521,863	NY	COD 2018
6	Bayonne Delivery Lateral	6	14	$17	$194,597	$232,562	NJ	COD 2012
	Average of AG Pipelines					**$323,941**		
1	CPV Valley Lateral	8	16	$61	$491,764	$521,863	NY	COD 2018
2	Bayonne Delivery Lateral	6	14	$17	$194,597	$232,562	NJ	COD 2012
3	Middlesex Expansion	2	16	$53	$1,892,857	$1,892,857	NJ	Anticipated 2021
4	Bayway Lateral	1	24	$31	$1,291,667	$1,370,727	NJ	COD 2018
5	Woodbridge Lateral	2	20	$32	$666,667	$750,775	NJ	COD 2015
	Average of Relevant Laterals					**$953,757**		

There are three critical flaws in AG's analysis:

- First, three of the six projects analyzed – Constitution, PennEast, and Northern Access – are interstate pipelines ranging 101 to 121 miles in length. A 100-plus mile project will have economies of scale not attainable for shorter power plant laterals.
- Second, none of those three projects were actually completed. Constitution was cancelled, and PennEast and Northern Access are on hold and may never be completed. The estimated costs for these projects do not reflect final cost overruns that plague Northeast pipelines.

[1] NYISO (Sept. 2020), "NYISO Staff Final DCR Recommendations" at p. 19, available online here ("NYISO Final Recommendations").

- Third, AG's averaging method arbitrarily discarded the highest and lowest-cost projects. The data in Figure 1 implies that the CPV Valley lateral was dropped despite it being the most relevant data point.

A valid benchmarking should not include 100-plus mile pipelines that are unlikely to get built. Rather, the benchmarking should include laterals that meet sensible criteria such as projects that: (a) connect power plants to interstate pipelines and are shorter in length, (b) are completed or are nearly complete and thus reflect the current regulatory environment and near-final costs, and (c) are in the vicinity of New York.

Two of the six projects considered by AG meet these criteria – the laterals for CPV Valley and Bayonne; the other four do not. Three additional relevant data points are CPV's Woodbridge lateral to Transco and the subsequent Middlesex Expansion to TETCO, and the TETCO Bayway lateral to Linden Cogen. The bottom half of Figure 1 shows these five projects. Their average cost is approximately $950,000 per inch-mile.

The $950,000 per inch-mile should be considered a low-end estimate as it is derived from historical costs. Future developers will face more issues today with siting, permitting, and construction, given the heightened regulatory and political environment, which makes completing a fossil fuel project in New York next to impossible. Notable, recent events include litigation against the Millennium lateral, delays to Atlantic Bridge, the Con Edison and National Grid natural gas moratoriums (citing interstate pipeline constraints), the cancellations of the Constitution and Northeast Supply Enhancement projects, and the opposition Iroquois is facing for adding gas compression on its system.

The difficulties of building a gas lateral in New York – and any fossil-related infrastructure, for that matter – can not be emphasized enough. If the demand curve technology is a fossil fuel-fired power plant, its cost must include a realistic estimate for the gas lateral. CPV requests that the NYISO Board direct NYISO staff to complete the benchmarking with an appropriate selection of projects.

2. Rockland County Gas Hub Mapping

As in prior demand curve resets, AG has outlined four criteria to select the gas hub for each power location: (a) market dynamics, (b) liquidity, (c) geography, and (d) precedent. The NYISO and AG have recommended TETCO M3 for Rockland County, which is not the correct selection when using the aforementioned criteria, for following reasons:

a. Market dynamics – TETCO M3 is a misaligned gas hub relative to Iroquois Z2 and Algonquin City-gates, as evidenced by TETCO M3's inferior market price correlation.
b. Liquidity – There is no liquidity to purchase gas at the TETCO M3 price, because transportation is not available. Without substantial further investment on TETCO, which conflicts with the Governor's and New York's goals, this transportation will not be available in the future.
c. Geography – TETCO M3 delivery points are geographically outside of New York, and interruptible transportation into Rockland County is not commercially available. This interruptible aspect comes with a cost and also an impact to availability not considered in the current modeling.
d. Precedent – NYISO and AG have continuously failed to explain their about-face from their position in the 2017 demand curve reset, whereby both entities endorsed Iroquois Z2 and FERC concurred.

There is no justification for changing the Rockland gas hub from Iroquois Z2 to one that is inferior and infeasible across all selection criteria. CPV requests that the NYISO Board direct

NYISO staff to retain the Iroquois Z2 gas hub or, if a change is made, assume Algonquin City-gates.

A. Market Dynamics – TETCO M3 has Weaker Price Correlation Which Overstates Net EAS Revenues

To assess market dynamics, AG evaluated the correlation between power and gas prices. The common metric for measuring correlation is the correlation coefficient. These values are shown in Figure 2 across three historical periods. In all periods, the correlation of TETCO M3 with Zone G power prices is lower than that of Iroquois Z2, TGP Z6, and Algonquin City-gates. The weaker correlation of TETCO M3 will artificially skew the net EAS revenues higher, because, under the net EAS model logic, the reference plant will experience upside when the power/gas disconnect produces higher spark spreads and limited downside when the disconnect results in lower spark spreads (as the downside result has a floor at zero).

Figure 2. Correlation Coefficients of Zone G Day-Ahead Power Prices with Daily Gas Prices

Timeframe	TETCO M3 *Recommended*	Iroquois Z2 *Current*	TGP Z6	Algonquin CG
2013 to Present	77%	86%	87%	88%
2015 to Present	76%	81%	83%	85%
Sep 2016-Aug 2019	75%	79%	82%	83%

B. Liquidity – TETCO M3 is Not Liquid in New York without Transportation Costs

TETCO M3 is a liquid gas hub. However, the TETCO M3 market zone stops shy of New York. Transportation is needed to get TETCO M3 gas to Rockland County. Firm transportation into Rockland County is fully-subscribed, and it is much more costly than the $0.27/MMBtu generic transportation cost assumed by AG. Interruptible transportation is unreliable, particularly during the winter months that are most profitable to the reference plant. An investor would not bank on interruptible transportation to meet gas needs. Thus, it can be said that there is no liquidity to purchase gas at the TETCO M3 price in New York.

As FERC has stated, whether alternative gas hubs have more or less liquidity is not dispositive as to whether their use is reasonable in estimating net EAS revenues, but lack of liquidity is an important factor.[2] For liquidity to be relevant to the net EAS revenues of a peaking facility, it must encompass what is necessary to deliver gas to the reference plant. From this standpoint, TETCO M3 fails to meet the liquidity criterion. TETCO M3 cannot be delivered to Rockland County without incurring pipeline congestion costs.

C. Geography – Interruptible Transportation into New York is Not Available as the MMU Claims

The TETCO M3 delivery points end in northern New Jersey before reaching Rockland County.[3] Pipeline transportation is needed to deliver the TETCO M3 gas. The firm transportation on Algonquin is fully subscribed and is held by long-term firm shippers, primarily gas LDCs, that consume the gas downstream. Theoretically, interruptible transportation ("IT") could be used to flow gas from New Jersey to Rockland County. This is the strategy contemplated by the MMU in its memorandum accompanying the NYISO recommendations.[4]

The threshold problem is that this strategy is completely speculative. Relying on Algonquin IT provides no guarantee of gas access to the power plant. The Algonquin pipeline is frequently constrained, subject to operational forced outages, and most of the transportation is

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[2] FERC (Jan. 17, 2017), "Order Accepting Tariff Filing Subject to Condition," issued in docket ER17-386 at P 155.

[3] For a full review of New York pipeline geography, *see* CPV (May 19, 2020), "CPV Valley Comments on the Gas Hub Mapping for the Lower Hudson Valley Reference Plant," presented to the ICAP Working Group, available online here.

[4] NYISO Final Recommendations, Appendix A, pp. 20-23, available online here.

held by gas LDCs that are reluctant to release it. Even if there is a small segment of pipeline that appears unconstrained after-the-fact, it is unreasonable to assume that the opportunity to exploit this availability could be commercially executed or would persist for any appreciable time. Accordingly, it would be unlikely for an investor to commit funds to a project with an unreliable fuel source, particularly a project without an energy hedge.

Looking past the threshold matter, the MMU's methodology does not accurately depict available capacity. To recap, the MMU calculated available capacity as the difference between Algonquin pipeline capacity (at Ramapo) and gas nominations made in the timely cycle. The MMU considered this volume to be available for IT flows to the reference plant. This approach is flawed for the following reasons:

1. <u>Assumes pipelines operate with zero margin</u> – the MMU has assumed that every MMBtu of capacity can be used up to the limit. In reality, pipeline congestion occurs before the pipeline is 100 percent utilized, and IT is not available in advance of that threshold. The pipeline may keep capacity for variability in withdrawals and anticipation of demands from no-notice service customers, for example. To give a sense of the impact, applying a 10 percent tolerance would restrict gas availability to the reference plant in over half of winter days.
2. <u>Does not consider lack of upstream supply</u> – there could be pipeline capacity but no molecules of gas upstream to reach the desired flow point. This could occur during high demand periods when upstream gas LDCs or power plants consume the available supply. So while pipeline capacity may appear available, it is not usable if there is no upstream supply.

3. Understates utilization by omitting the nomination cycles – the MMU considers utilization in the timely cycle but not the evening cycle, intraday 1, intraday 2, and post cycles. Each of these cycles represents an opportunity for firm shippers to take priority over IT customers. For an ex-post analysis to be credible, it must use the culminating volumes.
4. Ignores IT unavailability – IT is often unavailable even when pipeline utilization suggests it might be available. This reality has been considered in the MMU's analysis, which undermines the methodology.
5. Monthly quantification is misleading – the MMU has quantified average availability over the month. This diminishes the apparent impact on the reference plant by implying that all days in the month are of equal value. In actuality, the reference plant earns higher daily net EAS value on days that IT is less likely to be available. Zeroing out the net EAS revenues for these days has a disproportionate impact on the overall result.

The MMU's analysis offers little if any support for TETCO M3 for Rockland County. An investor would not base its investment decision off an interruptible gas supply on Algonquin. Instead, an investor would account for the generally-understood cost of getting gas to the plant, which includes pipeline transportation costs and, for Rockland County, is embodied by the delivered gas price indices of Iroquois Z2 and Algonquin City-gates.

D. Precedent – Departure from Precedent is Not Supported

The currently-effective ICAP demand curve for the Lower Hudson Valley is based on the net CONE of the Rockland County reference plant. That reference plant is assumed to burn Iroquois Z2 gas. The Iroquois Z2 determination was contested in the previous demand curve reset. NYISO and AG advocated for Iroquois Z2, and FERC ultimately accepted their recommendation. The TETCO M3 recommendation goes against all of the arguments made and the record at FERC.

Throughout the stakeholder process, CPV has continuously asked for a justification for the switch to TETCO M3 when it is inferior to Iroquois Z2 across all selection criteria. No satisfactory rationale has been given. The NYISO proffered one criticism of Iroquois Z2 that pertains to geography, and this is not an issue, because Iroquois Z2 gas can be backhauled on Algonquin to Rockland County.[5]

Lacking a justification for the switch and recognizing the flaws in the MMU's analysis, the NYISO Board must direct NYISO staff to maintain Iroquois Z2 as the gas hub for Rockland County. In an event that a change is made, a viable alternative would be Algonquin City-gates.

3. Owner's Costs

AG has materially understated the costs that a power plant owner would incur to develop and finance the reference plant. Two obvious near-omissions are owner's development and financing fees.

AG has assumed $370,000 for owner's development costs. This cost is a fraction of what CPV incurred developing each of half a dozen gas-fired power plants in the eastern U.S. It takes at least five years to develop a gas-fired plant, typically longer in New York, over which time considerable internal and external labor costs are incurred. For example, CPV Valley incurred $30 million in development costs from the project's 2007 inception to financial close in 2015. For the reference unit being considered, a developer would expect to spend $5 to $7 million in internal labor and a comparable amount in external labor for a total of $10 to $14 million. AG's

[5] NYISO Final Recommendations at p. 35. "Iroquois Z2 was not recommended for Load Zone G (Rockland County) because it is less representative of a readily accessible pipeline for gas-fired resources located west of the Hudson River within the lower Hudson Valley."

$370,000 cost is a fraction of realistic costs. That figure is just four percent of the $9.3 million (2020$) assumed by Lummus Consultants International, Inc. ("Lummus") in the prior demand curve reset.[6]

AG has defended its development costs in two ways. First, AG has stated that the gas lateral costs reflect all-in pricing and thus include some development costs. Second, AG has compared a subset of owner's costs in the current reset to a similar subset in the prior reset to show that, overall, owner's costs have not declined.

Neither argument is persuasive. While it is plausible that the gas lateral cost could include some development costs, it would only include the portion associated with the lateral, which is a small part of overall development costs. Neither is the high-level comparison meaningful. A comparison of total costs does not justify nearly omitting a $10 million-plus cost category. Finally, the development cost cannot be construed as being covered by contingency. Development costs are discrete costs that must be budgeted for. If contingency is allotted to known costs, the contingency bucket would quickly be usurped, which would defeat the purpose of carrying contingency.

The second omission is financing fees. Projects that are financed with non-recourse debt incur substantial costs for debt underwriting. Underwriting fees are typically a couple percent of the debt face value with another percent or more for the lead arranger. There are also fees paid to an investment bank to support the equity raise.

[6] NYISO Final Recommendations at Appendix D, p. 92.

According to Appendix D in the NYISO Final Recommendations, financing fees are included in the AFUDC/IDC line item.[7] This does not seem to be factually correct based on how AG states the costs are calculated.

> "Construction financing costs, including Allowance for Funds used during Construction (AFUDC) and Interest during Construction (IDC), were estimated during the construction period for each type of plant assuming the same 55/45 split of debt and equity and 6.7% cost of debt assumed for the project as a whole… construction financing costs are estimated at 6.80% of overnight capital costs for simple cycle units…"[8]

Per AG, AFUDC/IDC is calculated as 6.8 percent of the capital cost. This is the cost of funds used during construction, whether they are from lenders (incurring interest) or equity investors (accruing equity returns). The 6.8 percent is derived from the costs of debt and equity and the construction cash flows, hence AG calling these costs "construction financing costs." These costs are separate from fees paid to financial institutions to raise debt and equity. The two cost categories were recognized separately (and appropriately) in the prior demand curve reset: $6.2 million for financing fees and $23.7 million for AFUDC/IDC. In this reset, the AFUDC/IDC cost is comparable yet financing fees are omitted altogether.

Recognizing the near-omission of development costs and financing fees, the NYISO Board should direct the NYISO staff to estimate the costs of these activities and include them in the capital cost of the reference plant for all locations.

Thank you for your consideration of these issues. This concludes CPV's comments.

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[7] *Ibid*.

[8] Analysis Group, Inc. (Sept. 9, 2020), "Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report," at p. 43, available online here.