July 1, 2020

To: New York Independent System Operator
Analysis Group
Burns & McDonnell

From: CPV Valley, LLC

Subject: Comments on the Initial Draft Demand Curve Report for Capability Years 2021/2022 through 2024/2025

To Whom It May Concern:

CPV Valley, LLC ("CPV") appreciates the opportunity to provide written comments on the Analysis Group's initial draft demand curve report. CPV's comments are the culmination of positions that CPV has stated publicly before the NYISO stakeholder community and presented separately in discussions with the Analysis Group and Burns & McDonnell ("AG" and "B&M," respectively, or collectively, the "Consultants").

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 assumptions and methodologies of the demand curve study.

CPV contends that the Consultants' preliminary recommendations underestimate the net cost of new entry ("net CONE") for the reference plant. CPV's chief arguments are as follows:

- Gas hub mapping for Rockland County – the assumed gas cost of TETCO M3 plus a $0.27/MMBtu adder is not attainable within the G-J Locality. The Texas Eastern pipeline is not geographically accessible from Rockland County, and the viable pathways are much more expensive than TETCO M3 plus $0.27/MMBtu. Viable pricing options are Iroquois Z2 plus transportation costs to Rockland County (i.e., the assumption from the most recently-completed demand curve reset), TGP Z6, Algonquin Citygates, or TETCO M3 plus $0.65/MMBtu, although this option is inferior to the first three due to weaker market correlation and precedent.

- Gas hub mapping for Zone C – the TGP Z4 200 Leg assumption does not provide for gas deliveries into New York. As defined, the index includes deliveries into Ohio and Pennsylvania, and the required transportation into New York is fully subscribed. This geographic disconnect is why TGP Z4 200 Leg prices are only weakly correlated with Zone C power prices whereas the viable options (e.g. TGP Z6 or Iroquois Z2) reflect gas pipeline constraints and are strongly correlated with Zone C power prices.

- Net energy and ancillary services revenues – the dispatch model assumes that the proxy plant can perfectly arbitrage across the energy and ancillary services markets in day-ahead and real-time. This dispatch logic ignores day-ahead gas price uncertainty, does not consider the prevalent gas pipeline restrictions that are impactful even when oil is not economic, and assumes that NYISO markets are infinitely liquid (as to negate any price impacts from buyout decisions). In doing so, the model overstates net E&AS revenues by 100% or more of what could realistically be achieved. AG's approach represents a marked departure from what profit-maximizing gas-fired generation assets in NYISO can actually earn, industry-accepted approaches in the financial community, and PJM's methodology. Plausible approaches would be to consider only day-ahead earnings, as PJM does; apply a scaling factor to reflect the uncertainties, as the NYISO does in its buyer-side mitigation studies for Controllable Lines; or correct the dispatch logic.

- Owner's costs – based on the June 5, 2020, report, Burns & McDonnell has understated the cost of the pipeline lateral in Zone G by a factor of three ($33 million impact), has nearly omitted development costs ($18 million impact), and has not included costs for water access and treatment (upwards of $15 million impact). CPV understands that B&M is reconsidering these costs in light of discussions with and information from CPV. Hence these comments are provided in case conforming updates are not made.

- EPC costs – CPV reiterates its request that B&M provide a more detailed breakout of the EPC costs comparable to what was shared in past demand curve resets. The demand curve model posted on June 10, 2020, includes a four-bucket breakout, but this is less detailed than the ten-plus line items that have been provided previously. As a result, market participants cannot assess the reasonableness of the EPC costs, which comprise over two-thirds of total costs.

- SCR in Dutchess County – it is extremely unlikely that a gas-fired power plant could be built in Dutchess County without installing selective catalytic reduction ("SCR") to limit NOx emissions. While there may technically be a legal pathway to do this, the rapid advancement of regulations in New York and onerous requirements of the Article 10 process make permitting without SCR an increasingly risky and unlikely proposition. Since the prior demand curve reset, nothing has changed that would make permitting without an SCR more feasible, so the prior FERC decision to assume SCR for Dutchess County should be maintained. The heightened regulatory and political environment should also prompt the consideration of including SCR for the rest-of-state plant.

Figure 1. CPV Position Summary

No.	Topic	CPV Position
1	Gas hub mapping for Rockland County	TETCO M3 plus $0.27/MMBtu is not physically or financially attainable. Viable options are Iroquois Z2 plus transportation costs (i.e. the status quo assumption), TGP Z6, Algonquin CG, or TETCO M3 plus $0.65/MMBtu, although this option is inferior to the first three.
2	Gas hub mapping for Zone C	TGP Z4 200 Leg is not a viable index, because it does not include deliveries into New York, and the required transportation (into New York) is fully-subscribed. Viable options include TGP Z6 and Iroquois Z2, among others.

3	Net E&AS revenues	The dispatch model ignores several realities of the gas and power markets and, in doing so, overstates the reference plant earnings two-fold.
4	Owner's costs	The non-EPC costs understate the costs of the pipeline lateral, understate owner's development costs, and omit the cost of water access and treatment. The aggregate cost impact is on the order of $60 million in capital costs.
5	EPC costs	CPV requests that B&M provide a detailed breakout of the EPC costs, comparable to what Lummus provided in the prior demand curve reset, so that market participants may assess the reasonableness of EPC costs, which comprise over two-thirds of total costs.
6	SCR in Dutchess County	Nothing has changed over the past four years that would make permitting in New York without SCR more feasible. The precedent to assume SCR for Dutchess County should be maintained, per FERC's decision in the prior demand curve reset.

1. Gas Hub Mapping for Rockland County

Summary: Analysis Group has recommended TETCO M3 as the gas hub for Rockland County. It is not physically or financially possible to get delivered gas into Rockland County solely at the TETCO M3 price, as this section will describe. While AG has included a $0.27/MMBtu adder, it is not clear what this adder represents and it nevertheless understates the cost of transportation. Viable options include Iroquois Z2 plus transportation costs, TGP Z6, Algonquin Citygates, and TETCO M3 plus $0.65/MMBtu, although this option is inferior to the others.

This section reviews key concepts of natural gas markets and then applies them to Rockland County to assess what gas options are viable.

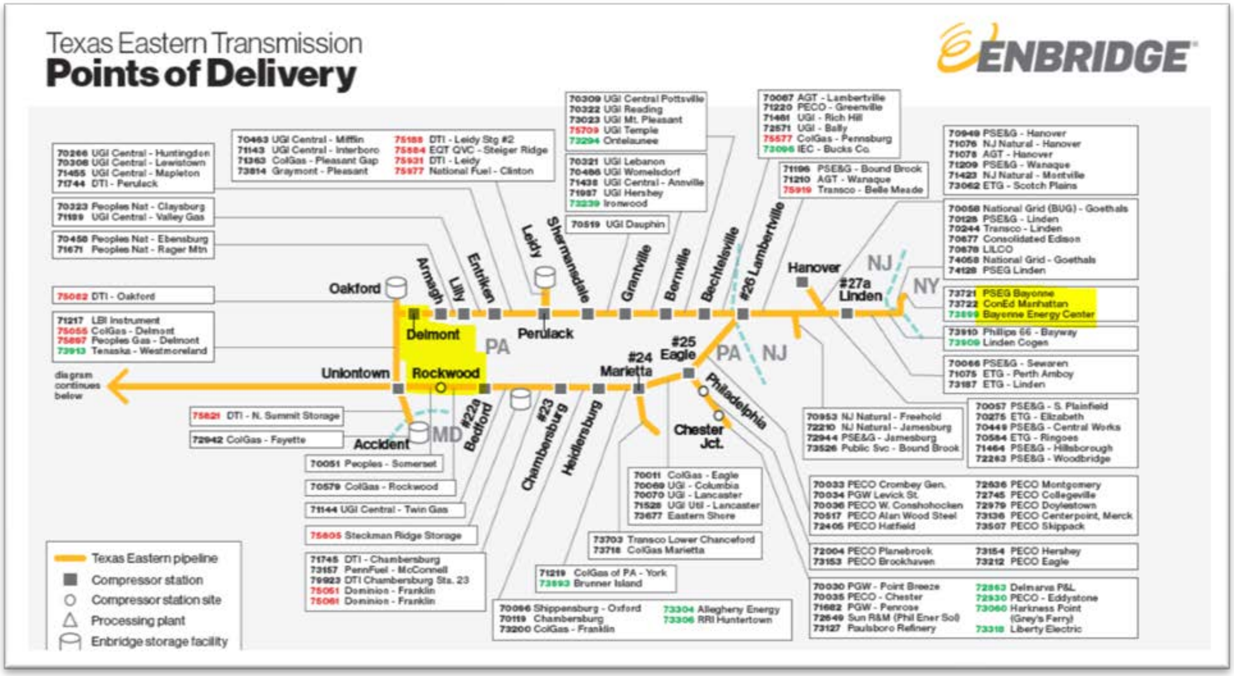
There are three basic elements to getting gas to a power plant: a commodity purchase, transportation on the mainline, and transportation on the lateral to the plant. Regarding the first two, an important distinction is whether the commodity cost includes transportation. A "delivered" index includes transportation; the cost of transportation is embedded in the price paid. Paying a delivered index price allows the buyer to take delivery off the pipeline in the region specified in the pipeline company's tariff. A "receipt point" index does not include transportation. The price paid is for receipt onto the pipeline, within specified locations, typically in a gas pooling area. To get delivery off the pipeline, a shipper must reserve pipeline capacity (provided that it is available) and pay the tariff transportation rate. For simplicity, the lateral transportation cost is ignored here as it is assumed that the reference project will own the lateral and not incur any associated variable costs (although this is an optimistic assumption).

An example of a delivered index is TETCO M3. The Texas Eastern Pipeline tariff defines the TETCO M3 market zone as "points east of and including the Delmont, Pennsylvania compressor station and east of the station located at Rockwood, Pennsylvania."[1] The delivery points, shown in Figure 2, span from the Delmont and Rockwood compressor stations in Pennsylvania and terminate at Con Edison's gas

[1] Texas Eastern Transmission, Inc. (June 2014), "Part 5 – Rate Schedules Index," definition of Market Zone 3 at Rate Schedule TABS-2, available online here.

distribution system. A buyer can take delivery in this vicinity without incurring additional transportation charges. Note that the tariff definition of the TETCO M3 market zone does not include deliveries into Rockland County or surrounding counties in New York.

Figure 2. Texas Eastern Points of Delivery



An example of a receipt point index is Millennium East receipts. The Platts Gas Daily definition is “receipts into Millennium Pipeline downstream of the Corning compressor station in Steuben County, NY, and upstream of the Ramapo Interconnect with Algonquin Transmission in Rockland County, NY.”[2] To buy gas on Millennium, a shipper must pay the Millennium East receipts price for receipt onto the pipeline and then separately pay the tariff transportation cost for delivery off the pipeline. The Millennium East receipt price is not attainable without paying the tariff transportation cost of $0.6518/MMBtu, provided that capacity is available.[3]

If a hub does not provide for delivery at a desired location, it is possible to buy transportation to the desired endpoint. If pipeline capacity is available, the shipper may reserve it at the tariff rate. If capacity is not available, the shipper may be able to purchase capacity bilaterally or via an open auction. The price paid for this capacity is expected to be at a premium to the tariff rate, otherwise the capacity would have been released.

An example that will be revisited later is TGP Z4 200 Leg. This index is defined as deliveries into Ohio and Pennsylvania along TGP’s 200 leg, but it does not include deliveries into New York. To get into NY,

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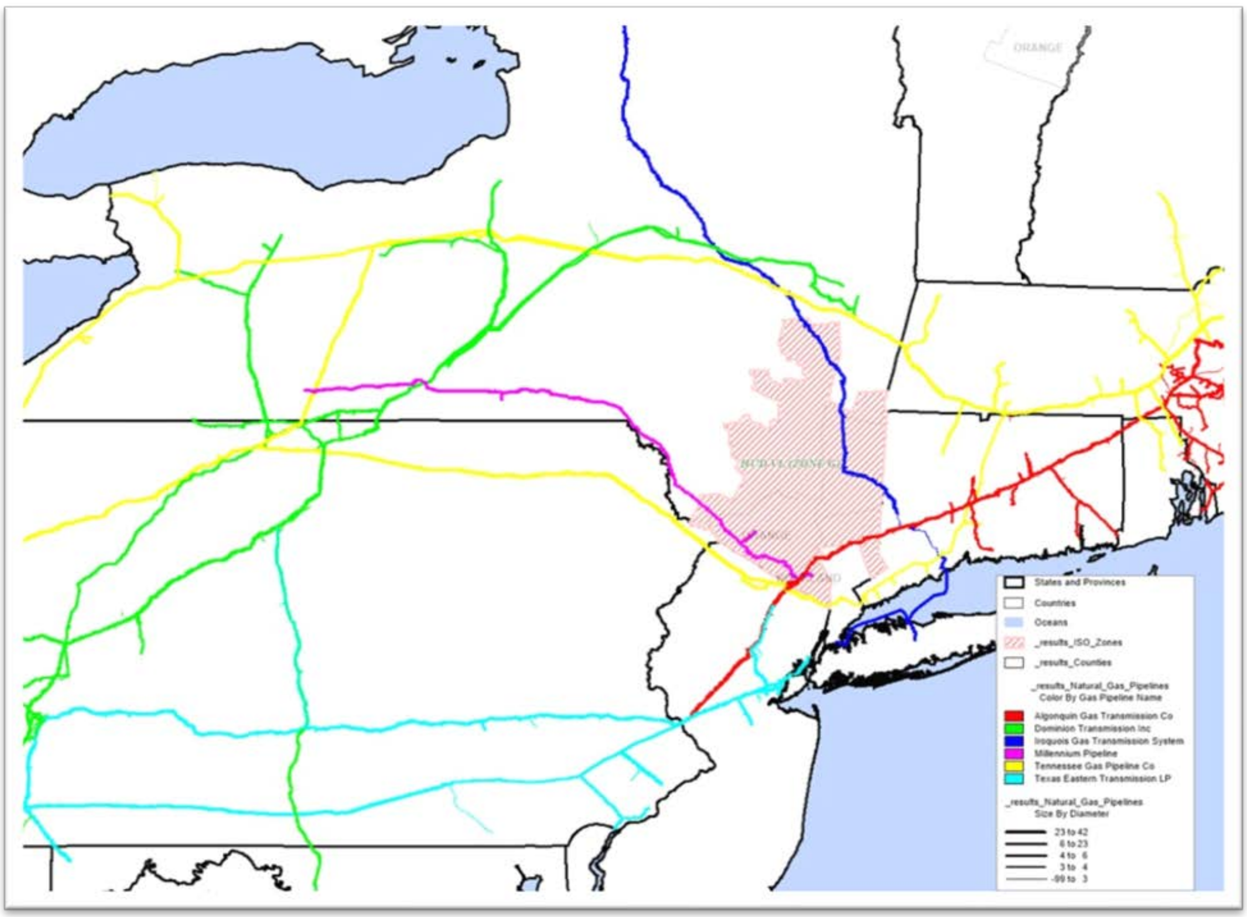
[2] S&P Global Platts (May 2020), “Methodology and Specifications Guide, US and Canada Natural Gas,” at p. 11, available online here.

[3] Millennium Pipeline, LLC (accessed June 2020), “Tariff Sheet Summary for Current Rates and Retainage Factors,” available online here. The Millennium tariff reservation charge for interruptible service (IT-1) is $19.769 per Dth-month, which is equivalent to $0.6499/MMBtu, plus a $0.0019/MMBtu commodity charge, for a total cost of $0.6518/MMBtu.

a shipper would have to buy transportation from TGP Station 219 along the 200 or 300 legs. This transportation is fully subscribed, and the cost would be the higher of the market and tariff rates.

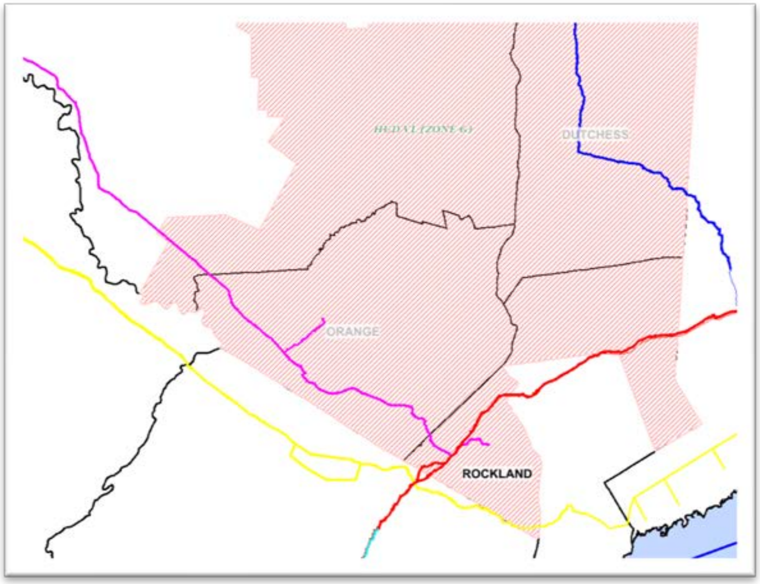
These concepts can be applied to assess what gas options are available in New York. Figure 3 and Figure 4 show the interstate pipelines in New York. Rockland County is transected by three interstate pipelines: the Algonquin Pipeline transects southwest to northeast, the Millennium Pipeline enters from the northwest and ends in the county, and the Tennessee Gas Pipeline clips through the southern tip of the county. A new gas-fired plant would need to interconnect to one of these three pipelines (via a lateral) and purchase gas delivered in Rockland County. The Iroquois Pipeline is also relevant; it runs through nearby counties to the east and can be accessed via back haul on Algonquin.[4] The Texas Eastern pipeline, to which TETCO M3 belongs, is not practically accessible within Rockland County.

Figure 3. Interstate Gas Pipelines in New York



[4] A back haul is a "paper transport" of gas by displacement against the flow on a pipeline, so gas is delivered upstream of its point of receipt.

Figure 4. Zoom-in on Rockland County

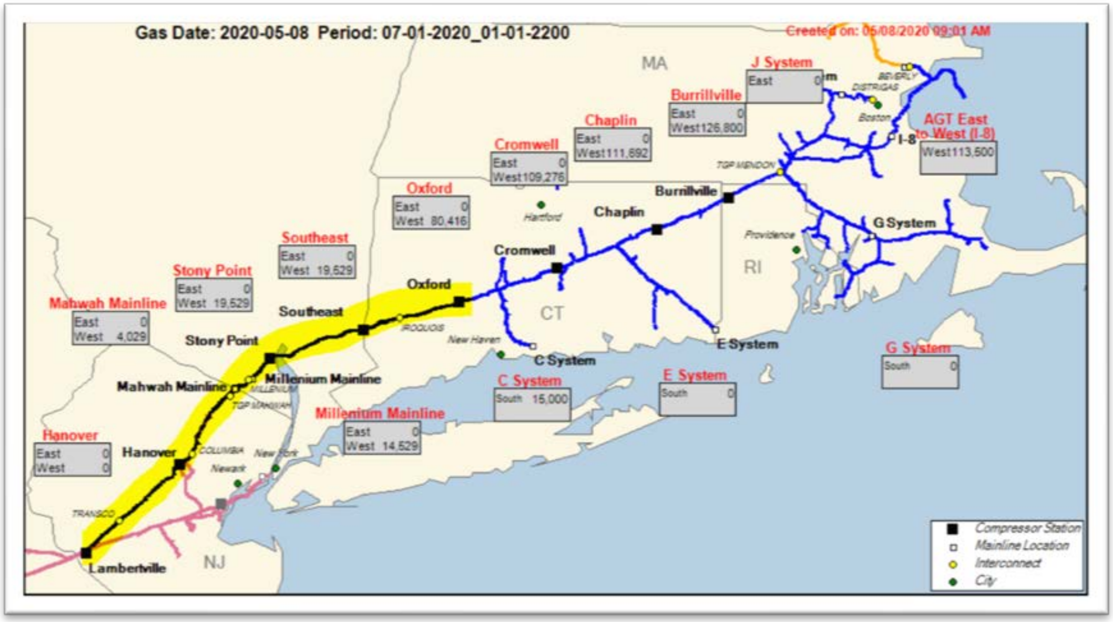


Algonquin – Starting with Algonquin (Figure 5), there are two relevant gas hubs: Algonquin receipts and Algonquin Citygates. Algonquin receipts provides gas upstream of Rockland County – the Lambertville, Hanover, and Mahwah interconnects – but transportation is not available to forward haul gas into Rockland County. This was determined by reviewing the subscribed capacity on Algonquin's Electronic Bullet Board ("EBB").[5] Eastbound capacity is not available at the necessary segments. That means it is not possible to get gas into Rockland County at the Algonquin receipts price plus transportation; it is not a viable option. The transportation might be purchased bilaterally, but the price paid will generally equate to the total cost of gas to the downstream delivered price, Algonquin Citygates. Algonquin Citygates is defined as deliveries to end-use facilities in Connecticut, Massachusetts, and Rhode Island. Because delivery is covered to Connecticut, a power plant in Rockland County could take delivery "early" in the path. **The Algonquin Citygates price is a viable option.** Finally, it is possible to buy gas on Iroquois Zone 2 at the Brookfield Interconnect (the interconnection between Iroquois and Algonquin pipelines in Connecticut) and backhaul the gas on Algonquin, paying the Algonquin transportation rate of $0.22/MMBtu.[6] The Algonquin website shows that there is 19,529 MMBtu/day of transportation available for back haul. **Iroquois Z2 plus $0.22/MMBtu is a second option.**

[5] Algonquin Transmission, LLC (accessed June 2020), "Unsubscribed Capacity Map," available online here, click capacity, click unsubscribed, click unsubscribed capacity map.

[6] Algonquin Transmission, LLC (June 2020), "Statement of Rates Showing Effective Rates Index," Sixth Revised Volume No. 1 Tariff, available online here. The base tariff rate of $6.5734 per Dth-month is equivalent to $0.22/MMBtu,

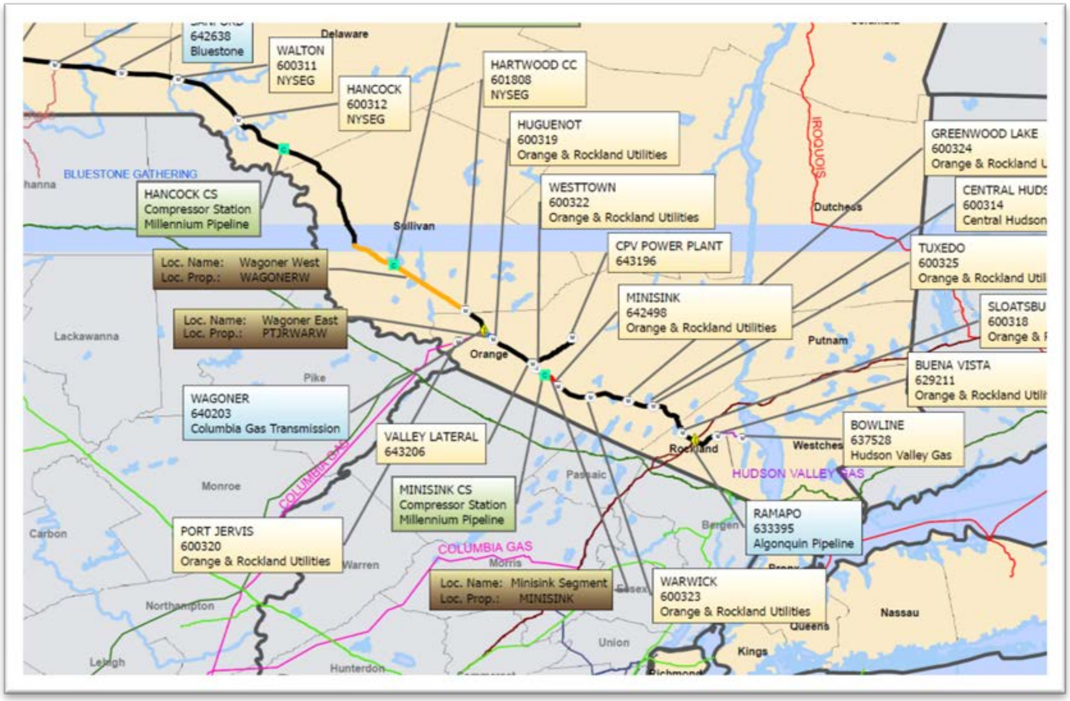
Figure 5. Algonquin Transmission



<u>Millennium</u> – The Millennium Pipeline (Figure 6) enters Rockland County from the northwest and crosses Algonquin at the Ramapo Interconnect, before terminating at the Bowline power plant near the Hudson River. The relevant gas hub on Millennium is Millennium East receipts, which the tariff defines as "receipts downstream of the Corning compressor station in Steuben County, NY, and upstream of the Ramapo Interconnect with Algonquin Transmission in Rockland County, NY." This is a receipt point index; transportation must be purchased for delivery off the pipeline at the tariff rate of $0.6518/MMBtu. There is no capacity available to flow from west to east, per Millennium's EBB.[7] However, there is 345,000 MMBtu/day available for back haul from Ramapo. The commodity price at Ramapo is TETCO M3, which reflects the cost of gas in northern NJ and on the Texas Eastern and Transco systems. <u>**A third option in Rockland County is to buy gas at Ramapo at the TETCO M3 price and pay the $0.6518/MMBtu charge for transportation on Millennium. However, this option is inferior to the other three, because TETCO M3 has weaker correlation (Figure 10) with Zone G power prices, and TETCO M3 was decided against in the most recently-completed demand curve reset.**</u>

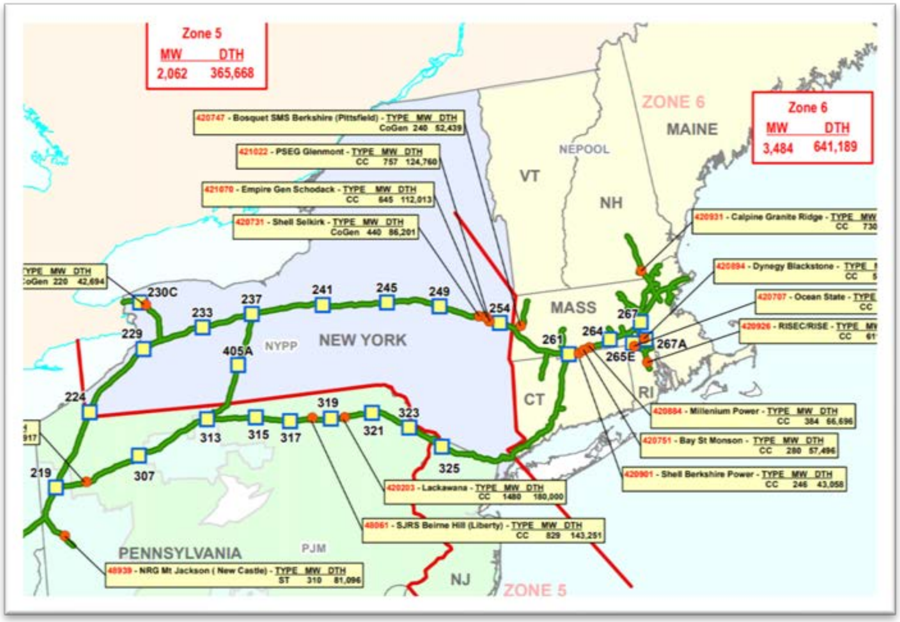
[7] Millennium Pipeline Company, LLC (accessed June 2020), "Unsubscribed Capacity by Point," available online here, click Millennium Pipeline, click Capacity, click Unsubscribed.

Figure 6. Millennium Pipeline



Tennessee – The 300 leg of the Tennessee Gas Pipeline runs through the southern end of Rockland County (Figure 7). Rockland County is in TGP Zone 5, demarcated by the red lines in Figure 7. There is no delivered market zone for the TGP Z5 300 leg, which means gas on the 300 leg must be transported from an adjacent zone. The two options are Zone 4 to the west and Zone 6 to the east. There is no capacity available eastward from Zone 4 per TGP's EBB. There is 204,000 MMBtu/day available flowing westward (backhaul) from Station 261. Gas could be transported from Station 261 at the TGP tariff rate of $0.0804/MMBtu; however, the simpler approach is to purchase the TGP Z6 300 leg, which delivers into Connecticut, and pick up the gas early in Rockland County. That avoids paying for transportation to back haul. **The fourth option is to buy TGP Z6 (300 leg) and take delivery in path in Rockland County.**

Figure 7. Tennessee Gas Pipeline



Analysis Group has recommended TETCO M3 plus a generic transportation charge of $0.27/MMBtu. There are several issues with this recommendation. First and foremost, the Texas Eastern Pipeline is not practically accessible from Rockland County. The only way to access it would be through an approximately 25-mile lateral costing some $100 million dollars. Analysis Group recognized the geographic disconnect in the prior demand curve reset, finding that TETCO M3 did not meet the geography criterion for Zone G (Figure 8). No physical infrastructure changes have been made to the Texas Eastern Pipeline since that time that would alter this determination.

Figure 8. Natural Gas Hub Selection Criteria from the Prior Demand Curve Reset

Load Zone G					
Decision Criteria		TGP Z6	TETCO M3	Iroquois Zn 2	Millennium
	Market Dynamics	Yes	Partial	Yes	Low correlation
	Liquidity	Yes	Yes	Variable	Low volume / low trades
	Geography	No	No	Yes	Yes
	Recommendation			✔	
Precedent	2013 DCR	No	Yes	Yes	No
	CARIS (2015) Phase I	Yes	No	No	No
	IMM (2015)	No	Yes	Yes	No

The other selection criteria – market dynamics and precedent – do not favor TETCO M3. TETCO M3 has a weaker correlation with Zone G power prices than do all of the viable options: Algonquin Citygates, Iroquois Z2 plus $0.22/MMBtu, and TGP Z6 (Figure 10). This statement is true when the correlation coefficients are calculated over 2013 to present, 2015 to present, and over just the last two years (Figure 10 below). Precedent favors Iroquois Z2 plus transportation costs, which FERC approved in the prior demand curve reset after much debate.

The cost of gas at CPV Valley is evidence of the inappropriateness of TETCO M3 plus the generic transportation cost adder. CPV Valley's realized cost of gas in 2019 was $3.03/MMBtu whereas TETCO M3 had a daily average of $2.36/MMBtu and $2.39/MMBtu when weighting daily gas prices by CPV

Valley's daily volumes, for a like comparison. The $0.64/MMBtu cost difference would have equated to $16 million for CPV Valley in 2019 alone.

To recap, the viable options for Rockland County are Iroquois Z2 plus transportation costs to backhaul from the Algonquin Pipeline, Algonquin Citygates, TGP Z6 300 Leg, and TETCO M3 plus $0.6518/MMBtu for transportation. The first three options have stronger correlations with Zone G power prices than TETCO M3 and thus are superior. The precedent at FERC adds weight to retain the status quo assumption of Iroquois Z2 plus transportation costs.

2. Gas Hub Mapping for Zone C

Summary: Analysis Group has recommended TGP Z4 200 Leg for Zone C. This gas hub, as defined in the tariff, does not provide for deliveries into New York, and transportation into New York is fully subscribed. Therefore, Analysis Group's recommendation, even with a $0.27/MMBtu generic adder, is not viable, and should be changed to a viable option such as TGP Z6, Iroquois Z2, or TGP Z4 200 Leg plus an appropriate adder that reflects the market value of transportation into New York.

The Tennessee Gas Pipeline defines the TGP Z4 200 Leg as "deliveries into TGP at all points of receipt on the 200 line in the states of Pennsylvania and Ohio as well as transactions at Tennessee's station 219 pool."[8] The index extends to Station 219 (but not further), shown in Figure 9. To get into central New York, a shipper would have to acquire transportation north along the 200 leg or northeast along the 300 leg. Transportation along these paths is fully subscribed according to TGP's EBB.[9] Therefore the capacity would have to be procured bilaterally, through an open auction, or as the result of a pipeline expansion.

The transportation cost from a bilateral or auction procurement would be commensurate with the market price spread between TGP Z4 200 Leg and downstream delivery points that reflects pipeline congestion from the field zone (i.e. TGP Station 219) and central New York. Two such hubs are TGP Z6 300 Leg and Iroquois Z2. The price spreads for these hubs to TGP Z4 200 Leg were $1.13/MMBtu and $1.60/MMBtu, respectively, on average over September 2016 to August 2019. These market prices are much higher than the tariff transportation rate of rate of $0.3327/MMBtu, which indicates that transportation is "in-the-money," and holders are unlikely to release their capacity at the tariff rate.[10]

Another potential option to acquire capacity is through a pipeline expansion. However, any expansion is virtually impossible to complete in New York. Getting additional gas into New York is not only difficult but exceedingly expensive. Several projects that were designed to provide additional capacity into constrained areas in the Northeast have been terminated due to regulatory and environmental reasons. Examples include Williams' Constitution and Northeast Supply Enhancement Projects and Tennessee Gas Pipeline's Northeast Energy Direct. The most recent pipeline expansions in the northeastern U.S., such as the Algonquin Incremental Market Project ("AIM") and the Enbridge Atlantic Bridge projects, have cost in the range of $1.00 to $1.50 per MMBtu.

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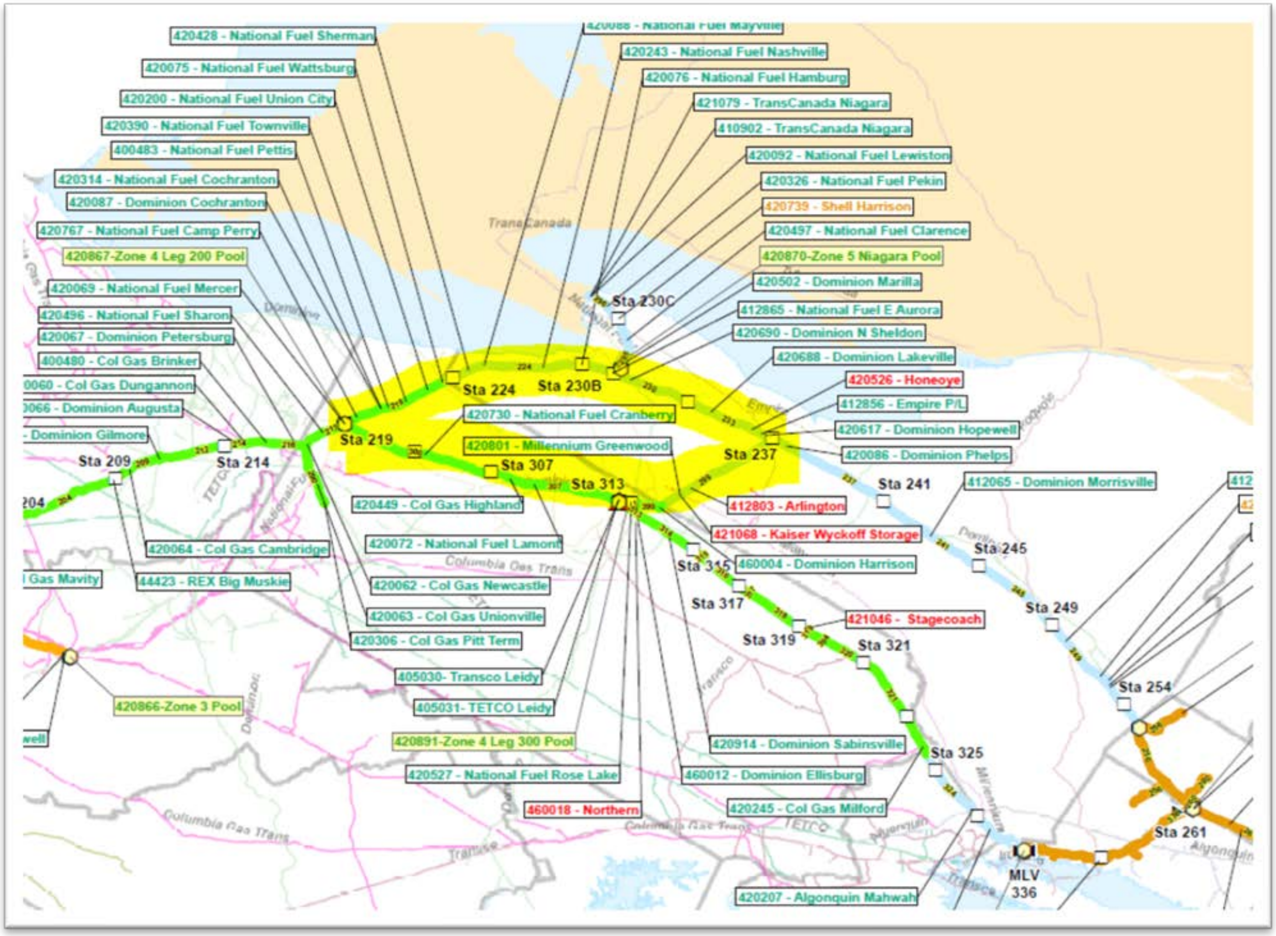
[8] S&P Global Platts (May 2020), "Methodology and Specifications Guide, US and Canada Natural Gas," at p. 11, available online here.

[9] Tennessee Gas Pipeline Company, L.L.C (accessed June 2020), "Segment Capacity," available online here, click capacity available, click unsubscribed, click segment capacity. Capacity is not available to flow forward from Station 219 to central New York (that is, in the "TD1" direction).

[10] Tennessee Gas Pipeline Company, L.L.C. (Dec. 2011) "FERC NGA Gas Tariff," rates for Interruptible Transportation: IT, available online here. The filed tariff rate reflects the historical levelized cost of a fully-depreciated asset. It bears little resemblance to the incremental cost to get gas to a certain location. The market price spreads and costs of comparable pipeline expansions are thus better indicators.

Figure 9. Tennessee Gas Pipeline System Map



A viable gas hub for NYISO Zone C will include the cost of pipeline congestion, which is most prevalent in the winter months of November to March. The TGP Z4 200 Leg does not embed these costs, because it provides for delivery upstream of the constraints, and the generic \$0.27/MMBtu adder is well below the costs implied by the market. The weak correlation of the TGP Z4 200 Leg gas hub with Zone C power prices is a reflection of this disconnect. The correlation coefficient, calculated over various historical periods ranging two to seven years, is less than 0.50, which suggests a weak or, at best, moderate correlation. Two viable options are to take delivery early on TGP Z6 or Iroquois Z2. These options provide for gas delivery in New York, embed the cost of pipeline congestion, and have a much stronger correlation with Zone C power prices (Figure 10).

Figure 10. Correlation Coefficients of NYISO Day-Ahead Power Prices with Gas Daily Prices

	Henry Hub	Tetco M3	Transco Z6 NY	Iroquois Z2	TGP Z6	Algonquin CG	Millennium East Receipts	Dominion North	TGP Zone 4 200 Leg
Zone G									
2013-present	51%	77%	56%	86%	87%	88%	30%	51%	46%
2015-present	41%	76%	51%	81%	83%	84%	30%	30%	46%
last 2 years	38%	77%	51%	81%	83%	85%	32%	31%	52%
Zone C									
2013-present	55%	76%	48%	81%	80%	80%	31%	53%	46%
2015-present	44%	72%	43%	74%	75%	75%	31%	32%	45%
last 2 years	40%	74%	44%	75%	76%	77%	28%	28%	46%

Finally, it may be argued that the $0.27/MMBtu gas adder somehow covers the cost of transportation from TGP Z4 200 Leg into New York. This flat dollar per MMBtu adder bears no relevance on the required transportation (that is anyway not available). The $0.27/MMBtu adder seems to have originated in the demand curve reset for Capability Years 2014-2016 to cover upstate gas utilities' LDC charges.[11] If TGP Z4 200 Leg is used and an appropriate transportation cost is estimated, the transportation cost should be a market-derived value and not an unrelated gas LDC charge.

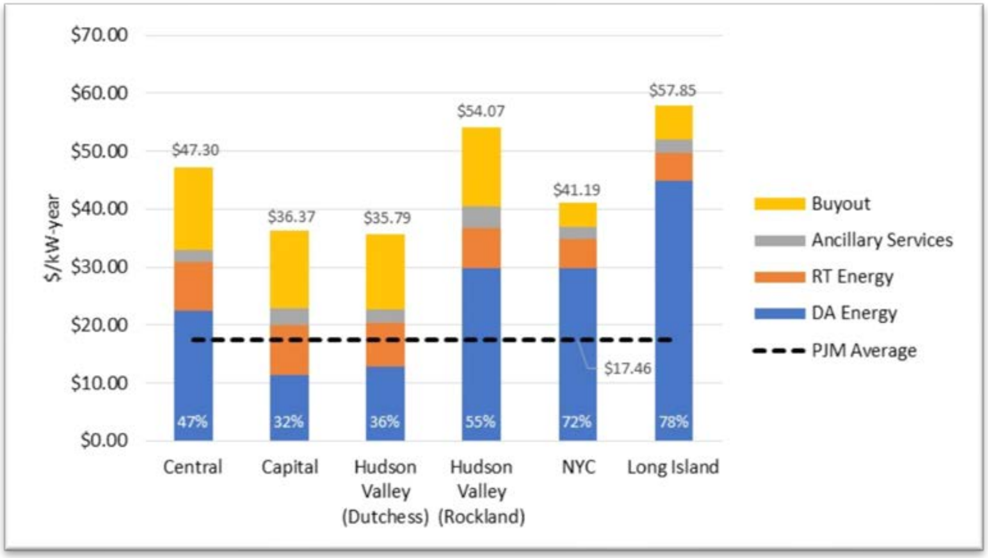
3. Net Energy and Ancillary Services Revenues

Summary – AG's dispatch model assumes that the proxy plant can perfectly arbitrage across the energy and ancillary services markets in day-ahead and real-time. This dispatch logic ignores day-ahead gas price uncertainty, does not consider the prevalent gas pipeline restrictions that are impactful even when oil is not economic, and assumes that NYISO markets are infinitely liquid (as to negate any price impacts from buyout decisions).

In doing so, the model overstates net E&AS revenues by 100% or more of what can realistically be achieved. These results are a marked departure from the actual earnings of profit-maximizing gas-fired generation assets in NYISO, industry-accepted approaches in the financial community, and PJM's methodology to estimate net E&AS revenues. Workable approaches would be to: (1) consider only day-ahead earnings and modest ancillary services revenues, as PJM does; (2) apply a scaling factor to rectify the perfect arbitrage assumption, as the NYISO does in its buyer-side mitigation studies for Controllable Lines; or (3) correct the dispatch logic through a series of one-off adjustments.

[11] NERA Economic Consulting (Aug. 2013), "Independent Study to Establish Parameters for the ICAP Demand Curve for the NYISO," at Table II-12 (p. 54), available online here.

Figure 11. Net E&AS Revenue Components as Estimated by AG



For starters, a sanity check is to look at the components that comprise the net E&AS totals. In Figure 11, each stacked bar represents the net E&AS revenue for a given location as calculated by the AG model over the three-year historical period, September 2016 to August 2019 (2019$/kW-year). Within each bar, the colored components denote the sources of the net E&AS revenues. The dashed line shows the average net E&AS revenues calculated by PJM for use in its mitigation reference prices.[12]

For example, the model predicts that the Rockland County plant would have earned $54.07/kW-year on average over the three year historical period. That total is comprised of $29.85/kW-year (55%) from day-ahead market energy, $6.82/kW-year (13%) from real-time energy, $3.90/kW-year (87%) from ancillary services, and $13.51/kW-year (25%) from buying out of suboptimal day-ahead and real-time positions.

The first observation is that opportunities outside of the DA market account for a large amount, and for half the locations, the majority, of net E&AS revenues. This result is inconsistent with the operating and financial results of the gas-fired plants that CPV has owned, operated, or managed, in similarly-structured markets throughout the U.S., for both simple-cycle CTs like the reference technology and combined cycle plants. The actual result, which CPV expects is shared by other generation owners, is that almost all net E&AS revenues are earned in the DA market, even with efforts to optimize performance in the market-based ancillary services and real-time markets. The rule of thumb is that optimization beyond the day-market is worth between 0.5% to 1.5% of the day-ahead market profits. In other words, a reasonable estimate of net E&AS revenues – one that an investor would consider or a market consultant would forecast – is no more than the blue bar shown in Figure 11 plus 1.5%.

The second observation is that the NYISO-estimated revenues dwarf those estimated by PJM. The main difference is that PJM only considers DA market energy margins and ancillary services revenues in its backcast. While PJM also employs a three-year historical backcast, PJM does not attribute revenue

[12] PJM Interconnection (Mar. 2020), "Default Zonal Net ACR," average of values reported for combustion turbines, converted to dollars per kilowatt per year, available online here.

potential to “buyout” opportunities or optimization in real-time.[13] PJM’s model is used to calculate net CONE values for all new entrants and net avoidable cost rate values for all existing entrants, and as such, represents an industry-accepted modeling approach. PJM’s exclusion of buyout profits and RT optimization should serve as an indication that the AG model has augmented the theoretical revenues well beyond what can be reasonably anticipated.

There are numerous reasons the AG model overestimates net E&AS revenues. Three are discussed here: day-ahead gas price uncertainty, gas pipeline restrictions, and market liquidity. The AG report describes some of these biases, as referenced below, yet AG errs in not correcting for them.

Day-ahead gas price uncertainty – The AG model dispatches the plant by lining up hourly power prices and daily gas prices, computing hourly variable costs, and dispatching the plant if energy margins from running exceed the startup cost. The logic assumes that the gas price is known with certainty when deciding whether to commit the plant in the day-ahead market. This is never the case in the NYISO market. A generator must submit its DA energy offers by five o’clock in the morning for the subsequent electric day. At that time, the gas price is not known, so the generator must offer based on an estimate of the gas price. In practice, the best information available at the time offers are due is the gas price for the prior gas day along with a rough sense of whether the price will be higher or lower due to the weather forecast. Nevertheless, the generator must estimate the gas price when offering. The tendency is to be conservative and offer on the higher end of expectations to avoid operating losses; underestimating the gas price would result in dispatch that is uneconomic. Conversely, overestimating the gas price results in foregone opportunity from not running when it would be economic. Gas price uncertainty is most prevalent during the winter months, which is when a large portion of net E&AS revenues are earned.[14] Gas price uncertainty is particularly problematic for peaking facilities (like the 7HA.02) that are expected to be marginal in the majority of their operating hours.

The AG model has not considered day-ahead gas price uncertainty. The model does include a meager gas price adjustment for intra-day gas purchases and sales (e.g. 10% for Zone G), but this simply adjusts the gas price when the plant optimizes by gaining or shedding commitments in real-time. In other words, the intra-day adjustment reduces the potential to earn (already questionable) real-time profits but does not address day-ahead gas price uncertainty, which is of much greater economic consequence.

This shortcoming could be addressed through a change to the AG model logic. One approach would be to assume that the best estimate of the gas price is the prior day’s price. Dispatch the plant on the prior day’s gas price and cost the plant on the actual gas price. This would produces instances of uneconomic dispatch and foregone opportunity (neither of which would be eligible for DAMAP or BPCG), to the extent as-bid gas costs deviated from actuals. Another approach would be to include a gas cost adder when determining day-ahead dispatch in winter months.

Gas pipeline restrictions – The AG model does not consider the impacts of gas pipeline restrictions. Pipeline restrictions, typically put in place during operational forced outages (“OFOs”), are a tremendous nuisance to gas-fired power plant owners. While there are varying severities, the typical restriction requires the power plant to conform gas burns to its day-ahead nomination, which is due around nine

[13] Another difference is historical market pricing; however, this impact is not expected to be significant. A review of on-peak market spark spreads shows that PJM values are within the range of the NYISO values underlying the net E&AS estimates, on average, over the period September 2016 to August 2019.

[14] For example, the Zone C reference plant earns 44% of its total net E&AS revenues during the three months of December, January, and February.

o'clock in the morning for the subsequent gas day (typically before the NYISO day-ahead schedules are published). Penalties for deviating are typically three times the Platts Gas Daily price and can be as high as $25/MMBtu.[15] Penalties are assessed for any deviations outside of the pipeline tolerance, which is typically just a couple of percent. During periods of high gas pricing and volatility, the restriction will be "don't be short." When making the day-ahead gas nomination, a power plant must err on the high side to avoid penalties from being short. During periods of low pricing, the restriction will be "don't be long," which creates the opposite tendency to be short at low prices. The daily differences between scheduled gas and burns – known as imbalances – accumulate on a rolling ledger. The pipeline restrictions systematically lead to gas inventories that are priced unfavorably relative to spot gas prices, that is, getting long gas at high prices and getting short gas at low prices.

The more severe restriction is requiring hourly gas burns to equal one twenty-fourth of the day-ahead gas nomination, known as being "ratable". This restriction forces generators to run at a flat output level throughout the gas day. This is problematic for a peaking facility that is typically only economic during a subset of the hours of the day. During such a restriction, the plant would only run if the energy margins earned during the profitable hours exceeded the losses in the other hours.

The AG report acknowledges that the model does not account for OFOs and attempts to address the issue by citing the ability to burn oil during such periods.[16] Burning oil will help when OFOs are in effect and natural gas prices are very high, such as $10/MMBtu, but there are many instances in which OFOs are in effect, and gas is still the more economic fuel. In this range of pricing, the AG dispatch model effectively ignores the OFO.

The AG model does not incorporate the impacts of pipeline restrictions and OFOs. A simple remedy would be to zero out the energy margin on days with OFOs or to insert an arbitrarily high gas cost ($999/MMBtu) that would allow the plant to operate on oil but not gas. Another approach would be to add logic that checks whether it is profitable to run the whole day at a flat output level on OFO days, to reflect the ratable requirement. Finally, a gas cost adder could be incorporated to reflect the positive differential between the realized gas price and average price that is driven by the directional restrictions described above.

A clear example occurs in December 2017 and January 2018 during the extreme winter weather known as the "Bomb Cyclone." Over these two months, the AG model predicts that the Zone C plant would have earned $35.83/kW-month, which is 27% of net E&AS revenues from the three-year historical period (Figure 12). However, it is unreasonable to attribute these earnings to the plant. The Tennessee Gas Pipeline was under an OFO for the most profitable days in this period.[17] The Zone C peaking facility would not have been able to earn these net revenues due to pipeline restrictions – i.e. stipulations not to be

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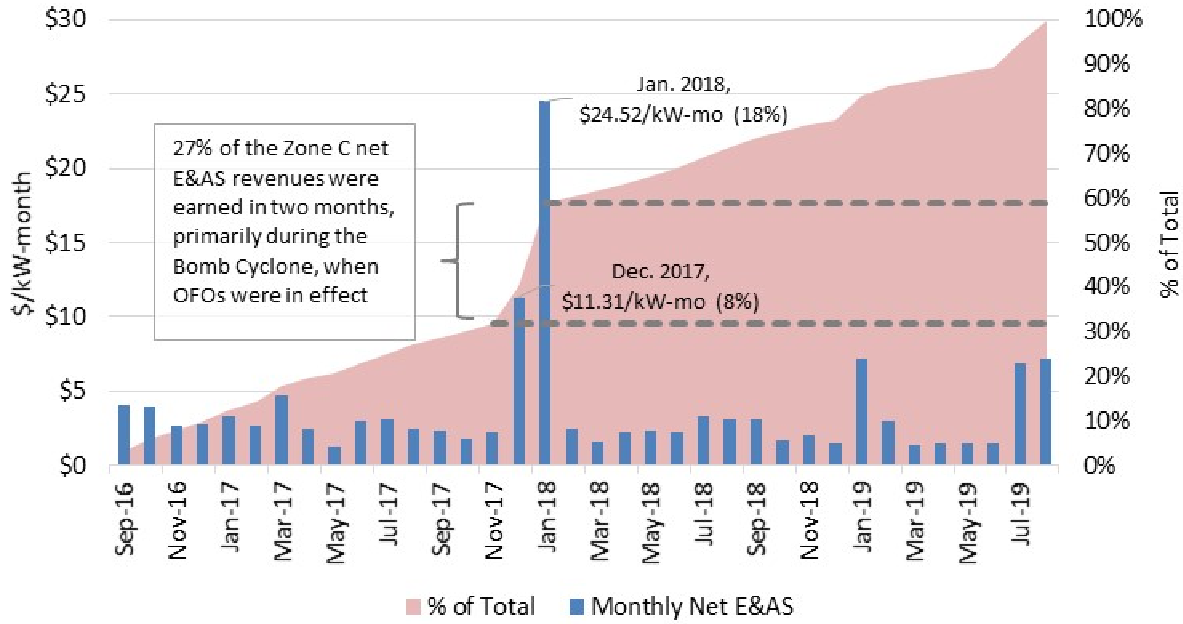
[15] For example, Algonquin Gas Transmission and Texas Eastern Transmission have OFO penalties of three times the Platts Gas Daily price. See section 26.8 of the Algonquin tariff available online here and section 4.3 of the Texas Eastern tariff available online here. The Millennium Pipeline Company OFO penalty is the greater of $25/MMBtu and three times the Platts Gas Daily price. See section 19 of the Millennium tariff online here, listed under Millennium Pipeline and tariff.

[16] Analysis Group (June 2020), "Independent Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years," at footnote 65, available online here. "[T]he model does not account for Operational Flow Order (OFO) restrictions which may limit hourly or daily deviations in gas burn from nominations. AGI does not expect OFOs to meaningfully affect the net EAS revenues of dual fuel plants, particularly in Load Zone J and K, where OFOs are more common. To the extent that OFO days are correlated with periods of high natural gas prices, these plants would already be expected to run on oil."

[17] *See*, for example, Tennessee Gas Pipeline Company (Dec. 29, 2017), "OFO Critical Day 1 Zones 2, 4, 5, & 6 12-30 Operational Flow Order," Notice ID 365875.

long or short and/or a requirement to burn gas ratably and harsh penalties for non-compliance. This is separate from and in addition to the issue that the assumed gas hub (TGP Z4 200 Leg) is a field zone price that provides for delivery in Pennsylvania, not New York. An appropriate correction would be to omit net E&AS revenues during the period the OFO was in effect, disallow gas operation (by entering an arbitrarily high gas price, as to only allow oil operation), or add logic to run ratably if economic.

Figure 12. Monthly Net E&AS Revenues for the Zone C Reference Plant



Market liquidity – The third issue is that the AG model assumes the energy and ancillary services are markets are infinitely liquid, as to negate any price impacts of incremental supply and buyout decisions from the facility in the energy and ancillary services markets. In actuality, the changes in supply associated with these market actions affect price, particularly for a peaking facility that is frequently marginal and frequently getting scheduled to sell into markets that do not have a substantial amount of volume.

A glaring example is that the proxy unit is getting scheduled for day-ahead operating reserves in almost all hours it is not running (in approximately 6,000 hours per year) and then it covers its day-ahead reserve sale by buying out at the commonly-lower real-time price (usually near $0/MWh). This strategy is unlikely to produce profits, or if it does, the opportunity would quickly be arbitraged away. There are ample operating reserves providers in NYISO yet not all of them are executing this strategy. Attributing profits to real-time optimization, nearly around-the-clock arbitrage of operating reserves, and real-time "buyouts" is merely awarding transient arbitrage opportunities, which is contrary to the intent of the demand curve reset to estimate likely net E&AS revenues for the theoretical entrant. Again, AG has acknowledged this bias towards overstating ancillary services revenues but has not made a corresponding adjustment.[18]

[18] Ibid. at footnote 59, "AGI assumes that LBMPs would not be affected by the incremental supply provided by the peaking plant, and thus do not account for the downward pressure that this additional supply may have on realized prices. In this regard, the **estimates may tend to overstate revenues**."

These three factors – day-ahead gas price uncertainty, gas pipeline restrictions, and illiquidity – elucidate why the AG model will consistently overestimate the net E&AS that the reference plant can earn. Market frictions and price uncertainty necessitated the NYISO to prescribe a "scaling factor" in its projections of the net E&AS revenues for Controllable Line facilities in its buyer-side mitigation studies. The NYISO applied a 50% reduction to the theoretical day-ahead and real-time profits.[19] The NYISO estimated this scaling factor as the ratio of estimated actual to theoretical earnings of merchant Controllable Line facilities. The NYISO could undertake this same exercise for existing merchant, gas-fired generators in New York: calculate a scaling factor as the ratio of actual earnings (as estimated using confidential reference level and billing data) to theoretical earnings for the same plant, compute the scaling factor for several plants, and aggregate the data so that the result may be disclosed publicly.

To summarize, the AG model overestimates the likely net E&AS revenues by as much as 100%. This is evidenced by a sanity check of the revenue components, a comparison to PJM's approach and results, deviation from industry expectations, and numerous assumptions acknowledged by AG that err toward overstating net E&AS revenues. It seems these shortcomings were largely overlooked in the prior demand curve reset when the newly minted net E&AS model was developed by AG. These shortcomings can be fixed through the one-off adjustments described above, or, more appropriately (and easily), through the application of a scaling factor that discounts for the likelihood of earning the theoretical profits.

4. Owner's Costs

The owner's costs in the June 5, 2020, report underestimate owner's costs by upwards of $60 million. The most obvious, material deficiencies are for the pipeline lateral, development costs, and water access and treatment, which have either been omitted altogether or incorporated at a small fraction of their likely costs. CPV provides these comments in reference to Zone G, in light of CPV's direct experience developing a power plant in that zone, but the Consultants should consider the comments broadly as applicable to all demand curve locations.

Pipeline lateral – B&M has assumed a $17.9 million capital cost to build a five-mile, 16 inch pipeline for the reference plants in Zones C, F, and G. This cost is approximately one-third of the cost, on a like-size basis, of the 7.8 mile CPV Valley lateral to the Millennium Pipeline ("Valley lateral"), which was constructed over 2017 to 2018, at a total cost of $70.7 million.[20] Based on this cost, the cost of a five-mile lateral in Zone G would be no less than $51 million. This cost should be considered a low-end estimate, as pipeline siting has only become more difficult since the 2018 completion of the Valley lateral.

Figure 13 compares the project specifications and computes the equivalent cost of the reference lateral using the Valley lateral per inch-mile lateral and metering and regulation ("M&R") costs. The Valley lateral cost $63.4 million with a per inch-mile cost of $511k (2020$). This per inch-mile cost is 2.8 times the B&M estimate of $180k per inch-mile. The Valley lateral M&R facilities cost $10.2 million (2020$), which is 2.9 times B&M's $3.5 million estimate. The largest costs of the Valley lateral, as documented in the Valley Lateral Cost Completion Report, were labor ($47.5 million), engineering and inspection ($6.5 million), and materials ($4.9 million). The reasons for the high costs are detailed in the report as well.[21] A

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[19] New York Independent System Operator (Nov. 2012), "Answer of the NYISO," docket no. EL12-98, at p. 4, stating the use of a 50% scaling factor, available online here.

[20] Millennium Pipeline Company, LLC (Oct. 2018), "Valley Lateral Project Cost Completion Report," publicly available online here in FERC docket no. CP16-17 ("Valley Lateral Cost Completion Report").

[21] At p. 2, "State, local, and federal preferences that led to the use of trenchless construction methods for approximately 40% of the Project, and the length and difficulty of the horizontal direction drills; design changes from the customer; construction challenges due to the presence of endangered species; storm water management,

comparable breakout has not been provided by B&M, but, based on total cost, it is evident that B&M has underestimated these major cost categories.

Figure 13. Gas Lateral Costs

		Millennium Lateral, Zone G		B&M Estimate for Zone G		Zone G Estimate, Scaled
Parameter		2018$ A	2020$ [1] B	2020 $ C	Multiplier = B / C = D	= D * C
Lateral length	miles	7.74		5.00		5.00
Diameter	inches	16.00		16.00		16.00
Lateral cost	$/inch/mile	$491,766	$511,633	$180,000	2.8	$511,633
Lateral cost	$	$60,900,257	$63,360,628	$14,400,000	4.4	$40,930,638
Metering and regulation	$	$9,806,008	$10,202,171	$3,500,000	2.9	$10,202,171
Total cost	$	$70,706,265	$73,562,799	$17,900,000	4.1	$51,132,809
Sources:		Millennium cost completion report		B&M 4/22/20 presentation (at p. 20)		
Notes:		[1] escalated at 2.0% inflation per 2019/20 and 2020/21 demand curve models				

The nearly three-times cost of the Valley lateral and M&R facilities (on a like-size basis) is on the low end of what a gas lateral in Zone G would cost. First, the additional length of the Valley lateral should serve to lower the average cost per inch-mile, as some of the cost components are fixed costs. Thus applying that average cost to a shorter pipeline is likely to underestimate costs.

Second, any future developer would likely face more issues today with siting, permitting, and construction, given the heightened regulatory and political environment, which have made permitting and constructing pipelines in New York next to impossible. Relevant, recent developments include the cancellations of Williams' Constitution and Northeast Supply Enhancement pipelines, Con Edison's moratorium on new gas interconnections in Westchester County that restricts new pipeline interconnections, and opposition to increasing pipeline compression on the Iroquois Pipeline.[22] Given these developments, it is reasonable to assume that all attempts to construct fossil fuel-related infrastructure in New York will be fiercely challenged.

It is unclear to what extent, if any, B&M incorporated the difficulties of constructing gas pipelines in New York State. Assuming a gas lateral cost that is one-third the cost of a recently-completed, comparable project, ignores the regulatory and political environment that developers face. Applying the cost multipliers discussed above and shown in Figure 13, CPV estimates that an appropriate cost for a five-mile project in Zone G is at least $51 million.

<u>Development costs</u> – B&M has assumed development costs that are less than one-sixth the cost of those underlying the currently-effective demand curves. There is no reasonable explanation for this dramatic cost decline, which has the effect of understating capital costs by at least $18.5 million.

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and construction disturbance limitations, noise limitation requirements, non-forecasted winter construction and above normal precipitation; increased legal costs from unanticipated litigation over state and federal permits, AFUDC higher due to overall cost increases, delay in project permitting and longer time frame to construct."

[22] Reference materials: Williams' Constitution Pipeline cancelation notice, Williams' Northeast Supply Enhancement cancelation notice, and Con Edison's natural gas moratorium in Westchester County citing "constraints on interstate gas pipelines."

Specifically, B&M's development costs include $0.4 million in "Owner's Project Development" costs, $1.0 million for the Owner's Engineer, $1.1 million for Owner's Project Management, and $1.0 million for Owner's Legal Costs. This total of $3.5 million is less than one-sixth of the $22.0 million cost underlying the demand curves that are in place now. In the prior demand curve reset, the engineering consultant, Lummus Consultants International, Inc., estimated development a $12.7 million cost for third-party services and $9.5 million for owner's development costs, expressed in 2020 dollars for comparison.[23]

In CPV's experience, for a project the size of the 7HA.02 (347.0 MW) being considered, a developer would reasonably expect to spend $5-7 million for third-party services and the same amount for internal labor, totaling $10-14 million, which is up to four times the amount B&M has assumed.

Water access and treatment – Water is essential for the operation of simple-cycle combustion turbines. The reference plant will require water for evaporative cooling, water washes, NOx control for fuel oil firing, and on-site service water and potable water use. B&M has not included the costs or stated the means of water access, treatment, and discharge. It appears that the analysis was based on utilizing onsite wells or surface water, which would very likely run into local opposition during the NYS Article 10 siting process. No water pipeline cost has been assumed, which would cost on the order of several million dollars. Finally, water discharge has not been contemplated. Water discharge is extremely difficult to permit in New York, and the likely permitting scenario would require Zero Liquid Discharge (ZLD), for which costs have not been included. A typical ZLD system would cost between $12 to 15 million based on CPV's experience on other projects, although the cost would vary based on the size and water quality specifications. B&M should revise its analysis to reflect the assumed means and associated costs of water access, treatment, and discharge.

5. EPC Costs

CPV reiterates its request that B&M provide a more detailed cost breakout of the EPC costs for the plant, comparable to what has been provided in past demand curve resets. Up until the June 10, 2020, ICAP working group, B&M had only provided the total dollar amount of EPC costs. The demand curve model posted on June 10 separated that cost into four buckets: labor, materials, turbines, and other. This categorization is far less detailed than the 10-line or more breakout provided in prior resets. Thus, it has not been possible for market participants to assess the reasonableness of the EPC cost, which represents over two-thirds of the total cost of the reference plant. The request for an EPC breakout has been made on a teleconference with B&M, publicly at the ICAP working group, and in writing by IPPNY, with no response received to date.

6. Selective Catalytic Reduction in Dutchess County

It is extremely unlikely that a gas-fired power plant could be built in Dutchess County without installing selective catalytic reduction ("SCR") to limit NOx emissions. While there may technically be a legal pathway to do this, the rapid advancement of regulations in New York and onerous requirements of the Article 10 process make permitting without SCR an increasingly controversial and risky proposition. It is unlikely that a developer would take on the risk of constructing without an SCR or would be able to get through the permitting process without such a concession.

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[23] Analysis Group, Inc. & Lummus Consultants International, Inc. (Sept. 2016), "Study to Establish New York Electricity Market ICAP Demand Curve Parameters," capital costs for the 1x0 GE 7HA.02 with dual fuel, at p. 113, available online here. Third-party costs are assumed to include permitting, legal, owner's project management and miscellaneous engineering, and studies. The $11.5 million sum of these categories is converted from 2015 to 2020 dollars at a 2.0% escalation rate. Similarly, the $8.6 million development cost is converted to 2020 dollars.

These considerations are consistent with FERC's rationale in the prior demand curve reset. FERC ordered to include SCR for the G-J Locality, because the then-current curves made that assumption, and nothing had since changed that would make permitting without an SCR more feasible. This statement continues to be true and thus the precedent should be maintained. In the order that retained SCR for the G-J Locality reference plant, FERC stated,

> "[W]e note that the current ICAP Demand Curve for the G-J Locality is based on a peaking plant design with SCR emissions controls. We agree with NYISO and IPPNY that nothing has changed since the last ICAP Demand Curve reset that would reduce the need for SCR emissions controls in the G-J Locality. Rather, we agree with NYISO that, for the Rockland County portion of load zone G, a nonattainment area for purposes of New Source Review requirements with very restrictive nitrogen oxides emissions thresholds, the peaking plant design must include SCR emissions controls. Furthermore, as NYISO explains, there are much higher nitrogen oxides emissions rates that result from operating on a dual fuel peaking plant's alternative fuel source. Because the G-J Locality includes a nonattainment area (the Rockland County portion of load zone G), NYISO appropriately concluded that the G-J Locality peaking plant design must include SCR emissions controls."[24]

This concludes CPV's comments.

[24] FERC (Jan. 2017), "Order Accepting Tariff Filing Subject to Condition," in docket no. ER17-386 at P 59, available online here.