UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc. **Docket No. ER21-____-000**

AFFIDAVIT OF PALLAS LEEVANSCHAICK, PH.D.

I. Qualifications

1. My name is Pallas LeeVanSchaick. I am an economist and vice president at Potomac Economics Ltd. ("Potomac Economics"). Our offices are located at 9990 Fairfax Boulevard, Fairfax, Virginia 22030. Potomac Economics is a firm specializing in expert economic analysis and monitoring of wholesale electricity markets, and is the Market Monitoring Unit ("MMU") for the New York Independent System Operator, Inc. ("NYISO").[1] Potomac Economics serves in a substantially similar role for ISO New England ("ISO-NE"), the Midcontinent Independent System Operator, Inc., and the Electric Reliability Council of Texas ("ERCOT").

2. As the MMU for the NYISO, Potomac Economics is responsible for assessing the competitive performance of the market, for identifying potential market design flaws and abuses of market power, and for commenting on the NYISO's implementation of the mitigation rules. This has included providing advice on numerous issues related to market design, economic efficiency, the determination of generator cost reference levels, and factors affecting the scheduling of generating units as well as preparing a number of reports that assess the performance of the NYISO's markets. I currently serve as the Director of the MMU for the NYISO.

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[1] Capitalized terms that are not specifically defined in this Affidavit shall have the meaning set forth in the filing letter to which this Affidavit is attached or, if not defined therein, the meaning set forth in the NYISO Market Administration and Control Area Services Tariff.

3. I have worked as an energy economist for over 19 years, focusing primarily on wholesale power markets. I have provided advice to Regional Transmission Organizations on transmission pricing, market design, congestion management issues, and market power mitigation. I have co-authored a number of studies evaluating the competitiveness of market outcomes in the NYISO, ISO-NE, and ERCOT. I have provided expert testimony before the Federal Energy Regulatory Commission ("Commission") related to the application of market power mitigation rules and the efficient design of operating reserve markets and congestion pricing.

4. I have a Ph.D. in Economics and a M.A. in Economics from George Mason University, and a B.A. in Economics and in Physics from the University of Virginia.

II. Background and Summary of Affidavit

5. As required by Section 5.14.1.2.2 of the NYISO's Market Administration and Control Area Services Tariff ("Services Tariff"), the NYISO conducts a comprehensive review of the ICAP Demand Curves every four years. This comprehensive review, commonly referred to as the ICAP Demand Curve reset ("DCR"), ultimately identifies: (1) proposed ICAP Demand Curves for the first Capability Year of the four-year period covered by each reset; and (2) the proposed methodologies and inputs the NYISO will use to execute the tariff-prescribed annual updates to determine the ICAP Demand Curves for the subsequent three Capability Years covered by the reset period. The current DCR addresses the ICAP Demand Curves for the 2021/2022 through 2024/2025 Capability Years.

6. Section 5.14.1.2.2.4.5 expressly identifies certain responsibilities of the MMU with respect to each DCR and requires that the MMU be afforded the opportunity to review and provide comments with respect to various components of the DCR, including the independent consultant's report and the recommendations developed by NYISO staff. The MMU actively participated in the DCR and provided feedback throughout the process on various proposed assumptions, inputs, and recommendations. Among other matters, the MMU provided feedback and analyses regarding the model and assumptions developed for purposes of estimating potential net Energy and Ancillary Services ("E&AS") revenues that could be earned by a hypothetical peaking plant in the NYISO-administered markets.

7. The purpose of this Affidavit is to address analyses undertaken by the MMU to evaluate: (1) gas cost assumptions for use in determining net E&AS revenues of the recommended peaking plants in Load Zone C and Load Zone G (Rockland County); and (2) assumptions regarding the cost of the recommended peaking plants to provide reserves, and the MMU's recommendations based on such analyses. This Affidavit is not intended to address all comments that the MMU may have regarding the NYISO's proposed results for the 2021-2025 DCR. The MMU reserves the right to submit separate comments in this proceeding to address matters related to the 2021-2025 DCR.

8. Circumstances may arise when these assumptions will over or under-estimate the fuel costs of individual generators on specific days. However, in devising assumptions to account for potentially relevant factors, it is also important to limit the complexity of the net E&AS revenue estimation model and the annual ICAP Demand Curve update process. The NYISO's proposed fuel cost assumptions for the peaking plants proposed for establishing each ICAP Demand Curve strike a reasonable balance that is likely to avoid significant over or under-estimation of net revenues while also avoiding undue complexity in the annual update process.

9. The remainder of this affidavit provides support for several of NYISO's proposed assumptions. Section III explains why the proposed gas cost assumptions for the Load Zone C peaking plant are reasonable. Section IV supports the proposed gas cost assumptions for the Load Zone G (Rockland County) peaking plant. Section V provides support for the NYISO's assumptions related to the cost of providing reserves. Section VI summarizes my conclusions.

III. The Proposed Fuel Costs of the Load Zone C Peaking Plant Are Reasonable

10. When estimating the net energy and ancillary services revenues of the proposed gas-only peaking plant design in Load Zone C, NYISO proposes to assume the peaking plant purchases natural gas at the Tennessee Gas Pipeline ("TGP") Zone 4 (200L) hub price plus a transport cost of 27 cents per MMBtu during the eight months from April to November and at the Niagara hub price plus a transport cost of 27 cents per MMBtu during the four months from December to March. In addition, NYISO proposes to assume the plant would

pay a 10 percent premium on gas to generate above its day-ahead schedule and receive a 10 percent discount on gas sold if it generates less than its day-ahead schedule.

11. These assumptions are reasonably representative of the opportunities that a hypothetical generator in Load Zone C would have to purchase gas and have it delivered if the generator was scheduled by the day-ahead or real-time market software. The remainder of this section discusses my reasons for supporting NYISO's proposed assumptions.

12. During the DCR, NYISO and stakeholders considered several other trading hubs, including Dominion North (which reaches into portions of central New York), TGP Zone 5 and Iroquois Zone 2 (which both include portions of eastern New York), as well as TGP Zone 6 (which includes New England portions of the Tennessee pipeline). I reviewed several analyses to evaluate NYISO's proposed approach to estimating the fuel costs of the Load Zone C peaking plant:

- Section A – Historical benchmarking analysis – This compares the actual operation of gas-fired units in Load Zone C to the operation that would be expected if the units' costs were consistent with NYISO's proposed gas hubs versus several alternative pricing hubs. This clearly demonstrates that the trading hubs for eastern New York and New England (*i.e.*, Iroquois Zone 2, TGP Zone 5, and TGP Zone 6) would not be appropriate for estimating the fuel cost of the Load Zone C peaking plant.

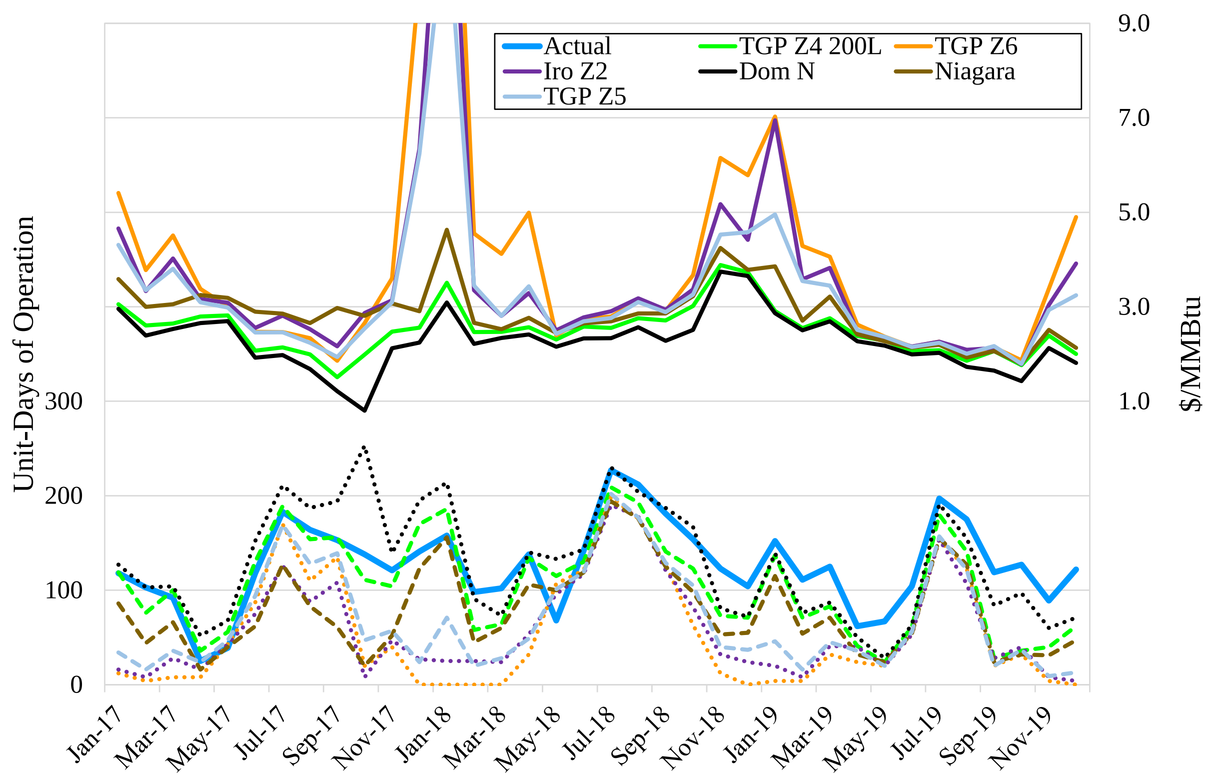
- Section B – Analysis of gas pipeline operational capacity data – This shows that pipeline constraints often arise during winter months that could increase the cost of transportation to Load Zone C from TGP Zone 4 (200L). Thus, the Niagara hub in western New York provides a closer, more reliable estimate of the price of gas during winter months.

A. Historical Benchmarking Analysis

13. Figure 1 compares the actual number of days of historical operation for nine gas-fired units in Load Zone C to backcast simulations for each unit under alternative fuel price assumptions. The simulations were performed using hourly day-ahead and real-time historical LBMPs at each respective generator's node, daily gas price indices for each

trading hub from S&P Global Market Intelligence (formerly SNL), and generator cost and operating parameters derived from unit-specific reference level data and unit-level emissions data from the U.S. Environmental Protection Agency ("EPA"). The lower portion of the chart (left axis) shows the actual combined days of operation compared to predicted days of operation using each gas hub price (dotted lines). The upper portion of the chart (right axis) shows the average gas price for each index used in the analysis. Generator results are presented in aggregated form because confidential unit-level reference data was used for the simulation.

Figure 1: Historical vs. Backcast Operation for Load Zone C Gas-Fired Plants



14. Use of the TGP Zone 5, TGP Zone 6, and Iroquois Zone 2 hubs produced consistently poor predictions of Load Zone C unit operations, leading to under-estimates in 34 of the 36 months shown, including all winter months. Use of the TGP Zone 4 (200L) and Dominion North hubs produced better predictions of actual Load Zone C plant operations. Notably, however, the Dominion North hub produced inflated estimates in many months. Although TGP Zone 4 (200L) generally produced better estimates than the Niagara hub, the Niagara

hub produced better estimates during the coldest winter months (*e.g.*, December 2017 and January 2018).

15. Overall, this analysis indicates that using the TGP Zone 5, TGP Zone 6, and Iroquois Zone 2 hubs would substantially under-estimate the operation and net revenues of the Load Zone C peaking plant, including during winter months. The analysis also indicates that using Dominion North is likely to overestimate the operation and net revenues of a peaking plant in Load Zone C. Furthermore, the analysis is generally supportive of the use of the TGP Zone 4 (200L) hub from April to November and the Niagara hub during the four colder months of the year (*i.e.*, December to March).

B. Analysis of Pipeline Operating Capacity Data

16. The area that NYISO defines as Load Zone C (also known as the "Central Zone") is downstream of the TGP Zone 4 (200L) and Niagara hubs, while Load Zone C is upstream of the TGP Zone 5, TGP Zone 6, and Iroquois Zone 2 hubs. Ideally, the trading hub for the Load Zone C unit should be chosen such that pipeline constraints rarely occur between the trading hub and Load Zone C.

17. Figure 2 shows a map of the Tennessee pipeline system in New York. TGP Zone 4 extends through northern Pennsylvania. The pipeline enters New York from Zone 4 in two locations (segments 224 and 299 in western and central New York, respectively). TGP Zone 4 (200L) is geographically accessible during times when capacity is available for transport on the Tennessee pipeline to Load Zone C. When interruptible transportation ("IT") service is available, the cost is $0.22/MMBtu, but during periods with excess pipeline capacity, secondary firm service is often available at a cost that is lower than the IT rate.

18. The TGP Zone 5 price refers to deliveries downstream of station 245, which aligns more closely with NYISO Load Zone F.[2] This index along with others such as Iroquois Zone 2

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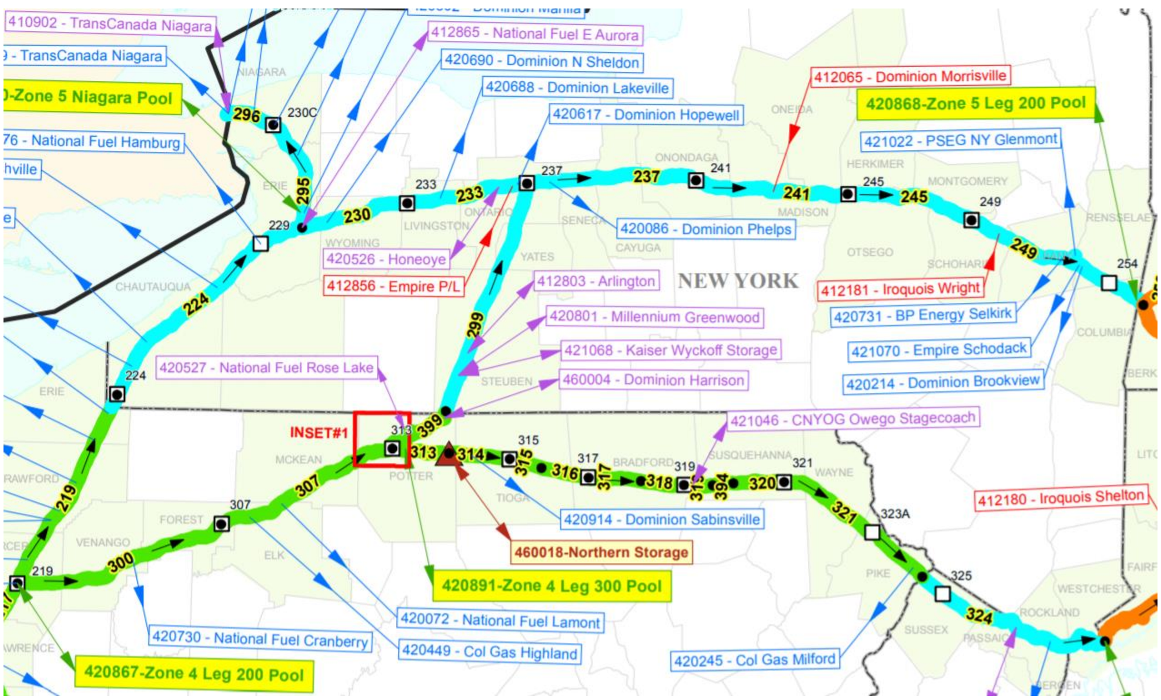
[2] S&P Global Platts defines TGP Zone 5 as "Deliveries from Tennessee Gas Pipeline Zone 5, downstream of compressor station 245 extending to and including station 254."

and TGP Zone 6 are geographically accessible, but they are not appropriate choices unless upstream alternatives (*e.g.*, TGP Zone 4 (200L) and Niagara) are not available.

19. Finally, the Niagara hub, which is located on the border with Ontario in western New York, is geographically accessible via the Tennessee pipeline to Load Zone C.[3] This hub generally reflects the price of gas being transported up the Niagara spur to the TransCanada pipeline, but it can be more accessible to Load Zone C generators when pipeline constraints arise upstream of Station 229 and on deliveries coming up Segment 299 resulting in potential availability concerns of delivering gas from TGP Zone 4 (200L) to Load Zone C.

Figure 2: Map of Tennessee Pipeline in New York

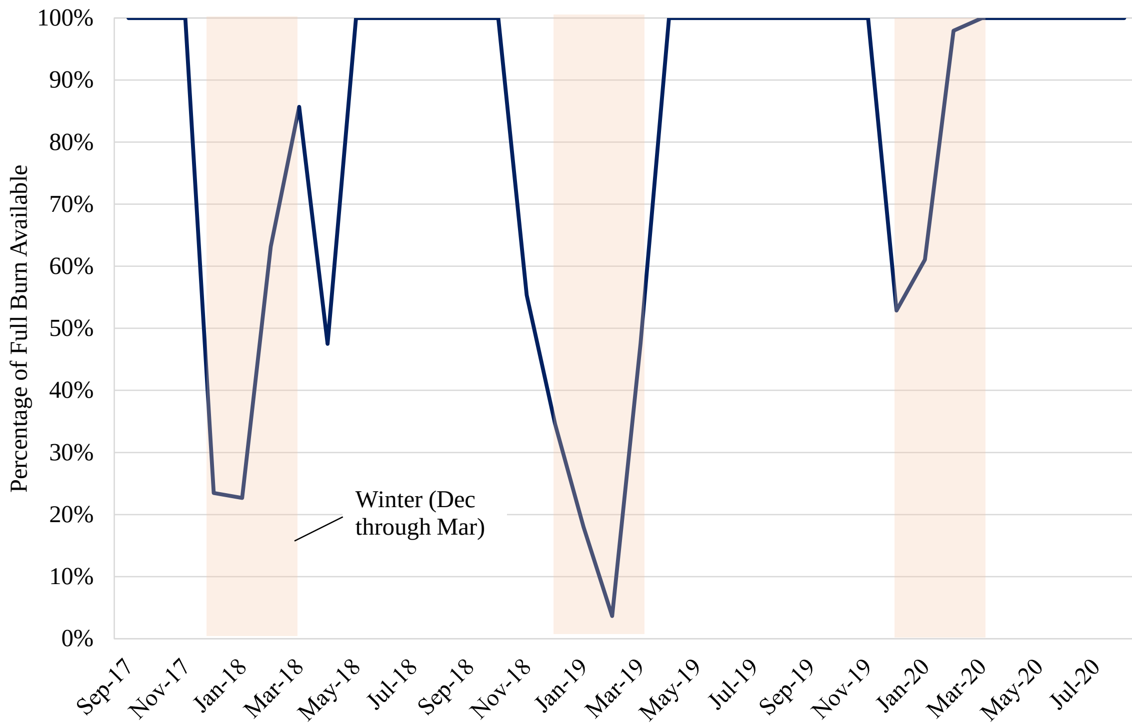


20. Figure 3 shows a historical summary of operationally available capacity on Tennessee pipeline segments entering New York from TGP Zone 4. Specifically, the figure shows the average share of the potential daily gas consumption of the peaking plant (approximately

3 S&P Global Platts defines Niagara as "Cross-border deliveries to and from TC Energy pipelines and the Niagara spur and loop lines, a border-crossing point between eastern Canada and the northeastern United States, north of Niagara Falls, NY Niagara Spur Loop line and Niagara Spur line interconnects are with Tennessee Gas Pipeline, National Fuel Gas Supply, Dominion Transmission and Texas Eastern Transmission."

75,000 Dth)[4] that would be available based on the operationally available capacity on Segment 224 connecting TGP Zone 4 (200L) to western New York. The figure also assumes capacity would be fully available on days when the price spread between TGP Zone 4 (200L) and locations downstream of Load Zone C on the pipeline (*e.g.*, TGP Zone 5) was less than the IT rate of $0.22/MMBtu.

Figure 3: Operational Available Capacity on TGP Segment 224



21. This data suggests that the purchase of gas at the TGP Zone 4 (200L) hub and transport to New York is often not possible during the winter period (*i.e.*, December through March). In such months, the use of TGP Zone 4 (200L) as the gas hub may overstate net revenues of the peaking plant in Load Zone C. Accordingly, the Niagara hub is a better choice during winter months, since pipeline constraints generally do not limit flows from the Niagara hub to Load Zone C.

4 Available capacity data is obtained from S&P Global Market Intelligence and reflects the lower of: (i) capacity available in the "Timely" nomination window and (ii) capacity available in the "ID3" nomination window.

C. Additional Considerations

22. Although there are circumstances when the proposed use of the TGP Zone 4 (200L) and Niagara hubs could lead to an over-estimate of net revenue on individual days, this potential should be weighed against circumstances when the assumptions could lead to under-estimated net revenue. First, the assumed cost of securing gas to cover 100 percent of day-ahead reserve commitments results in a cost of providing reserves that is relatively conservative. Second, the 10 percent premium or discount for intraday fuel purchases or sales is also likely to be excessive on most days. Third, the analysis assumes the Load Zone C peaking plant will pay $0.27/MMBtu for gas transportation, which is reasonable given that the interruptible transportation rate on the Tennessee pipeline to Load Zone C is $0.22/MMBtu. However, this is conservative given that secondary in-path service is often available at a price below that of interruptible service during relatively unconstrained periods. Finally, the annual run hour restriction of 1,060 hours for the Load Zone C peaking plant to comply with NOx emission standards limits the extent to which net revenues increase if gas prices are under-estimated.[5]

D. Conclusions Regarding Load Zone C Gas Price

23. The gas hub should be selected recognizing that the cost of fuel in western and central New York is generally lower than in eastern New York, including in winter months. Gas hubs associated with eastern New York such as TGP Zone 5, TGP Zone 6, and Iroquois Zone 2 are therefore not appropriate for Load Zone C. Direct transport from the TGP Zone 4 (200L) region to Load Zone C is often not available in winter, which may result in overstated net E&AS revenues if this hub is used in all months. Therefore, I support NYISO's proposal to use the Niagara hub price plus a transportation adder of $0.27/MMBtu in winter months (*i.e.*, December through March) and TGP Zone 4 (200L) plus a transportation adder of $0.27/MMBtu in all other months for the Load Zone C peaking plant.

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[5] This limitation arises because the proposed peaking plant design for Load Zone C is a gas-only unit that is not equipped with selective catalytic reduction ("SCR") emissions control technology. Instead, the unit is subject to an emissions restriction to allow for permitting as a "synthetic minor source."

IV. The Assumed Fuel Costs of the Load Zone G (Rockland County) Peaking Plant Are Reasonable

24. When estimating the net energy and ancillary services revenues of the proposed dual fuel peaking plant in the Rockland County portion of Load Zone G, NYISO proposes to assume the peaking plant purchases natural gas at the TETCO M3 price plus a transport cost of 27 cents per MMBtu. In addition, NYISO proposes to assume the peaking plant would pay a 10 percent premium on gas to generate above its day-ahead schedule and receive a 10 percent discount on gas sold if it generates less than its day-ahead schedule. This assumption appropriately reflects opportunities that a hypothetical peaking plant in Rockland County would likely have to obtain fuel, which will result in reasonably accurate estimates of the net energy and ancillary services revenues of the proposed peaking plant.

25. Gas can be transported from the TETCO M3 region to Rockland County via the Algonquin pipeline. The major bottlenecks on the Algonquin pipeline, which restrict flows to demand centers in New England, are downstream of Rockland County. Analysis of pipeline data indicates that transport on the Algonquin pipeline into Rockland County is generally available and that the resulting estimates of net revenue for the Load Zone G (Rockland County) peaking plant are reasonable.

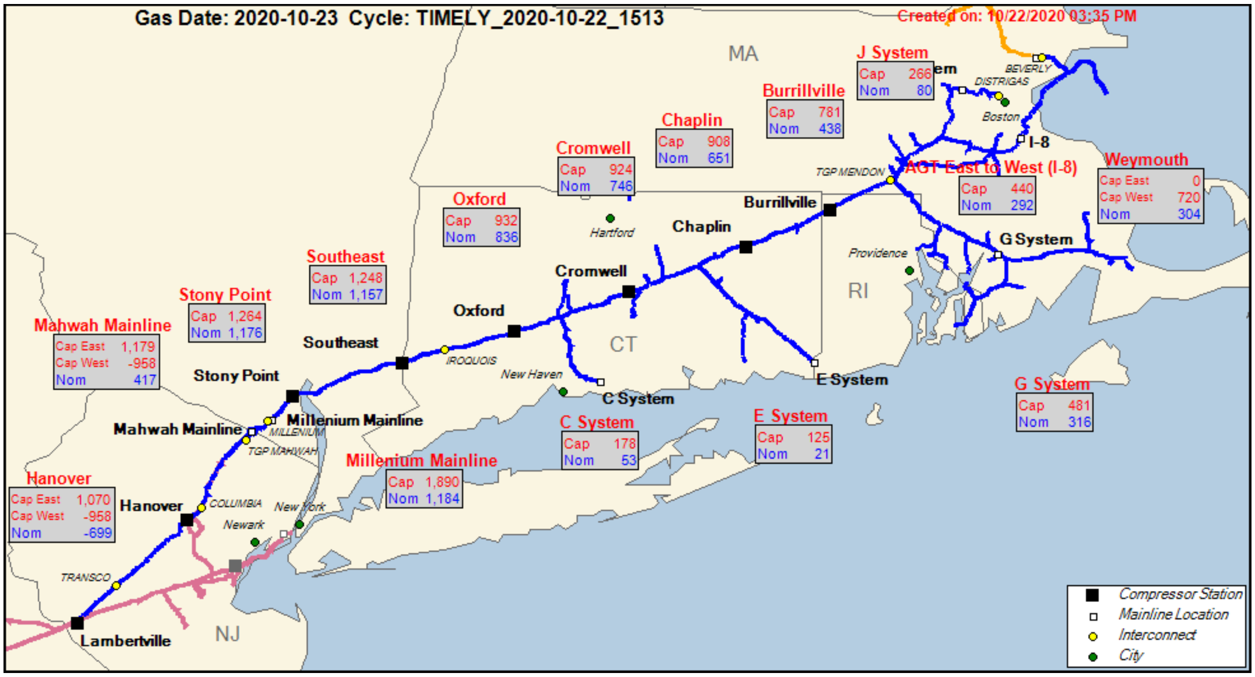
A. Geography of Rockland County and Algonquin Pipeline

26. Rockland County is in southeast New York, between the New Jersey border and the Hudson River. The TETCO M3 market zone does not geographically include Rockland County, but it includes points of interconnection with the Algonquin pipeline at Lambertville, NJ and Hanover, NJ.[6] The Algonquin pipeline passes through Rockland County, including compressor stations at Ramapo (where it interconnects with the Millennium pipeline) and Stony Point. After crossing the Hudson River at Stony Point into Westchester County (NY), the Algonquin pipeline continues to its primary downstream delivery locations in Connecticut, Rhode Island, and Massachusetts (corresponding to the

6 S&P Global Platts defines the TETCO M3 index as applying to “Deliveries from Texas Eastern Transmission beginning at the outlet side of the Delmont compressor station in Westmoreland County, PA, easterly to all points in the M3 market zone, except for deliveries to Transcontinental Gas Pipe Line at Lower Chanceford.”

Algonquin Citygates delivery region).[7] The Algonquin pipeline interconnects with the Iroquois pipeline in Brookfield, CT.

Figure 4: Map of Algonquin Pipeline



27. Gas can be transported from the TETCO M3 region to Rockland County by paying for transportation on the Algonquin pipeline. While forward-haul firm transport capacity is currently not available, I would not anticipate that the peaking plant would seek to procure longer-term forward-haul firm transport due to its low capacity factor. The peaking plant can meet its daily fuel needs by purchasing secondary capacity from holders of firm transport rights that have spare capacity available on that day, such as marketers or local gas distribution companies (LDCs), or by paying for IT when it is available.[8] The Algonquin pipeline AIT-1 interruptible tariff rate of \$0.2867/MMBtu is comparable to the \$0.27/MMBtu transport cost proposed by the NYISO.

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7 S&P Global Platts defines the Algonquin Citygates trading location as "Deliveries from Algonquin Gas Transmission to all distributors and end-use facilities in Connecticut, Massachusetts and Rhode Island."

8 Algonquin's tariff permits firm transport customers to transport gas to secondary points within their base flow path or outside of that base flow path (provided that quantities do not exceed the holder's segment entitlements and subject to curtailment via critical notices). Such nominations are referred to as secondary in path and secondary out of path.

28. The cost of acquiring secondary transport depends on the opportunity cost of the owners of the transport rights. This opportunity cost is lower than the IT rate when spare pipeline capacity is available. The opportunity cost can be higher than the IT rate when the delivery location is downstream of a constrained pipeline bottleneck (unless the price spread between upstream locations in New Jersey and downstream locations in New England is smaller than the IT rate).[9]

29. Gas price divergence between regions is typically caused by pipeline constraints that limit the transport of gas. For example, during the period September 2017 to August 2020, the average difference between the Algonquin Citygates and TETCO M3 gas prices was $0.15/MMBtu on days when utilization on all Algonquin pipeline segments between Rockland County and Massachusetts were below 95 percent.[10] Thus, the actual cost of transportation would often be less than NYISO's $0.27/MMBtu assumption.

30. The value of transport rights on a constrained pipeline depends on whether the relevant segment or delivery location is upstream or downstream of constrained bottlenecks. A holder of transport rights for a delivery location upstream of a binding constraint faces an opportunity cost that is aligned with prices in the upstream area, not the downstream area, since it cannot use those rights to transport additional gas past the constraint. Rockland County is geographically downstream of the TETCO M3 delivery area but upstream of the Algonquin Citygates and Iroquois Zone 2 delivery areas. Hence, it is important to consider whether major pipeline constraints occur upstream or downstream of Rockland County.

B. Analysis of Transport Availability on Algonquin

31. This section evaluates gas transport availability between the TETCO M3 region and Rockland County based on: (1) transport restrictions announced via Algonquin critical notices, (2) operationally available capacity data for the Algonquin pipeline segments in Rockland County, and (3) analysis of the impact on estimated net revenues of instances of reduced pipeline capacity availability. These evaluations support NYISO's proposal to

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9 The maximum variable commodity charge for firm transportation service on the Algonquin pipeline is $0.0042/Dth. Market opportunity costs are therefore likely to be more material than the tariff rate for secondary marketers of firm transport.

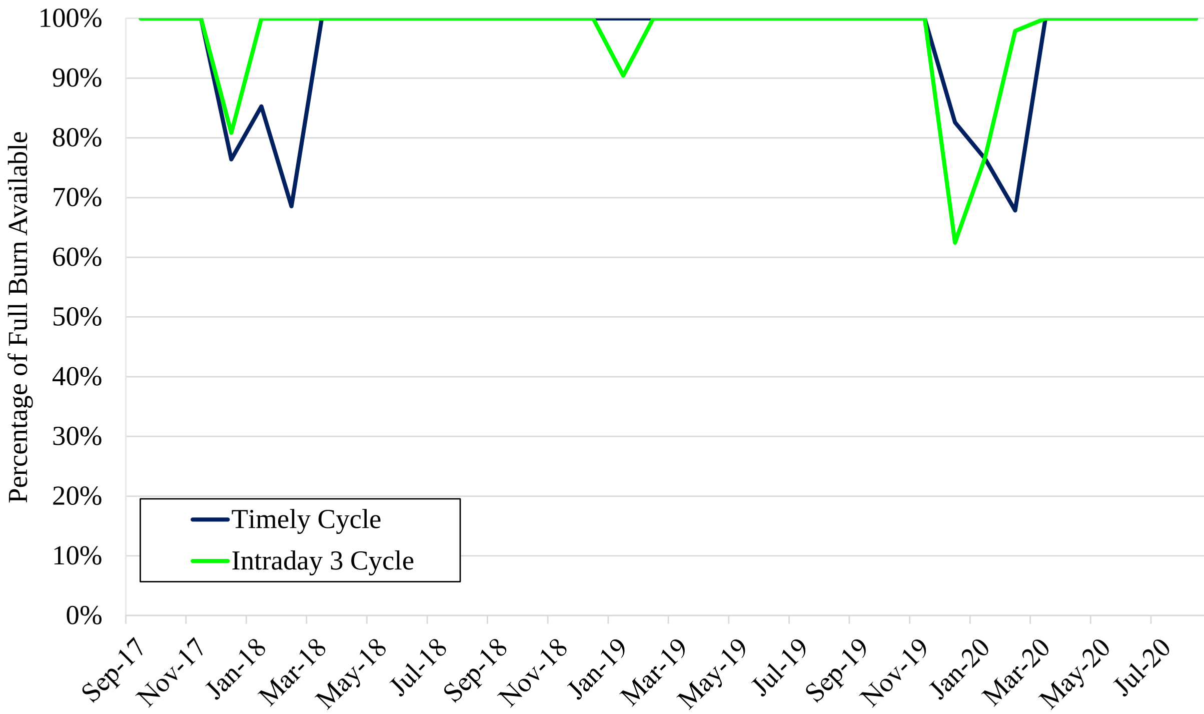
10 Segments include Millennium Mainline, Stony Point, Southeast, Oxford, Cromwell, Chaplin and Burrilville.

assume the Load Zone G (Rockland County) peaking plant would be able obtain natural gas at the TETCO M3 hub price plus a transportation adder of $0.27/MMBtu.

32. Algonquin announces restrictions on customers' gas transport nominations via daily critical notices when conditions warrant such restrictions. In 2019, Algonquin announced restrictions on nominations sourced from points west of its Stony Point Compressor Station for delivery east of Stony Point on 363 days, but did not announce restrictions on west-to-east transport for delivery west of Stony Point on any days. Stony Point is at the eastern border of Rockland County and is the last station before the Algonquin pipeline crosses the Hudson River into Westchester County (NY). Algonquin also frequently placed restrictions on deliveries across other downstream constraints in Connecticut, Rhode Island and Massachusetts. This data suggests that while transport on Algonquin is frequently restricted, the main bottlenecks are located downstream of Rockland County. As a result, these restrictions are unlikely to adversely impact the availability of transport on the segments of the Algonquin pipeline that facilitate deliveries to Rockland County.

33. Figure 5 analyzes the average daily operationally available capacity on the Algonquin pipeline segment passing through the Millennium Mainline station in Ramapo, NY. This segment would convey deliveries into Rockland County. The figure shows the share of the potential daily gas burn for the peaking plant (approximately 75,000 Dth) that could be satisfied by the operationally available capacity. The average available share was 100 percent in most months, and it covered a high percentage of potential daily burn even in cold winter months. This is likely a conservative measure, as a peaking unit typically will not generate for all hours of a day. Furthermore, the recommended peaking plant design for Load Zone G (Rockland County) is dual fuel and, therefore, also has the option to run on oil during the small number of days when gas may be uneconomic to procure from TETCO M3 or otherwise not available.

Figure 5: Operationally Available Capacity on Algonquin Millennium Mainline Segment



34. Although pipeline limitations have been infrequent on Algonquin's Millennium Mainline (Ramapo) segment, I reviewed how often such limitations might limit a peaking plant in Rockland County from operating when expected in the net revenue analysis conducted during the DCR. Available capacity was sufficient to cover 89 percent of the hypothetical peaking plant's expected operation over the period September 2017 through August 2020.[11] By contrast, if transport was restricted by availability at Stony Point (*i.e.*, further downstream on Algonquin beyond the segment that accommodates deliveries to Rockland County), only 41 percent of its operation would have been feasible. Hence, while available capacity to transport into Rockland County was occasionally limited, it was significantly less constrained than transport to points further downstream of Rockland County (including the Algonquin Citygates and Iroquois Zone 2 market areas).

35. Table 2 reports net revenue estimated for the hypothetical peaking plant in Load Zone G (Rockland County) for purposes of determining the G-J Locality ICAP Demand Curve for

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[11] This values was determined using the lower of the Timely and Intraday 3 cycles each day to be conservative. This period is the three year period of historic data required by the tariff for use in determining the estimated net revenues for the peaking plants in establishing the ICAP Demand Curves for the 2021/2022 Capability Year.

the 2021/2022 Capability Year (*i.e.*, \$32.31/kW-year) compared to two scenarios using alternative assumptions. First, the "restricted by availability" scenario assumes that on days when available pipeline capacity was less than the peaking plant's modeled gas consumption plus a safety margin of 10 percent, the net revenue for the peaking plant is based on a blend of TETCO M3 and Iroquois Zone 2 prices.[12] Using the blended gas price on days when availability concerns could potentially arise, the resulting estimated net E&AS revenues would fall by just \$1.6/kW-year (1.4 percent of the annual net cost of new entry (CONE) value).

36. By contrast, using the Iroquois Zone 2 price at all times (to be conservative) would result in a \$7.0/kW-year reduction of estimated net E&AS revenues (6.1 percent of the annual net CONE value). Compared to the "restricted by availability" scenario methodology, use of Iroquois Zone 2 would not be appropriate because it would significantly under-estimate the net revenues that the proposed peaking plant in Load Zone G (Rockland County) could reasonably anticipate earning from participation in the NYISO-administered markets.

Table 2: Load Zone G (Rockland County) Net E&AS Revenues[13]

Gas Hub Assumption	Load Zone G (Rockland County) Net E&AS Revenue (\$/kW-year)
TETCO M3 + \$0.27	\$32.31
TETCO M3 + \$0.27, Restricted by Availability	\$30.70
Iroquois Zone 2 + \$0.27	\$25.29

37. Although the more complex "restricted by availability" price blending methodology may be more accurate under certain conditions, I recommend against using it for several reasons. First, the scenario demonstrates that even if pipeline gas constraints were explicitly considered, it would have only a small effect on the overall net revenue estimate. Second, this methodology used in the scenario would require significant additional complexity that would tend to undermine the transparency, predictability, and

12 For example, on days where there was no available capacity on the Millennium Mainline segment, the Iroquois Zone 2 price was given 100% weight. On days when available capacity only partially covered the plant's preferred TETCO M3 gas consumption, Iroquois Zone 2 was given a weight of [1 – Available Capacity / (TETCO M3 gas consumption * 110%)].

13 Net E&AS revenues were calculated using the Final Thermal Net E&AS Model on September 15, 2020 and do not include the VSS adder.

understandability of the net E&AS revenue model proposed by the NYISO. Third, the potential for some degree of over-estimation of net revenues by not accounting for occasional pipeline limitations should be weighed against simplifying assumptions that tend to under-estimate net revenue. In particular, secondary firm transport service would be available on many days for less than the $0.27/MMBtu assumption proposed by the NYISO. Overall, NYISO's proposed assumption to use TETCO M3 as the gas hub for the Load Zone G (Rockland County) peaking plant strikes a reasonable balance that should avoid significant under or over-estimation, and the proposed method will not be overly complex to implement.

C. Conclusions regarding Load Zone G (Rockland County) Gas Hub

38. Given the complexities of natural gas scheduling, no assumption regarding fuel supply arrangements can perfectly predict market participants' costs under all circumstances. Any particular set of assumptions may over-estimate costs in some circumstances and under-estimate costs in others. Thus, NYISO's assumption should strike a reasonable balance that does not result in a substantial over or under-estimate of the peaking plant's net revenue.

39. The analysis indicates that pipeline bottlenecks on Algonquin occur downstream of Rockland County, beginning at Stony Point. Available capacity data indicates sufficient capacity from TETCO M3 to serve a peaking plant in Rockland County on the vast majority of days. While Algonquin is constrained in Rockland County on a small number of winter days, the effect of these days on the net E&AS revenue estimates is small. By contrast, the use of Iroquois Zone 2 or Algonquin Citygates on all days would have a large negative effect on net E&AS revenues, despite the fact that there is surplus pipeline capacity entering Rockland County on the majority of days. For these reasons, we support the NYISO's proposal to use of TETCO M3 plus a transportation adder of $0.27/MMBtu as the gas hub for Load Zone G (Rockland County).

V. Cost of Fuel to Provide Operating Reserves

40. NYISO proposes to assume a $2.00/MWh cost of reserves for dual fuel peaking plant designs (*i.e.*, Load Zones G (Dutchess County), G (Rockland County), J, and K). This

assumption is reasonably consistent with the costs that such units are likely to incur from being scheduled for reserves in the day-ahead market. It is also consistent with the availability bids of dual fuel generators offering to supply reserves in the day-ahead market under workably competitive conditions. The remainder of this section provides support for the proposed assumption regarding the cost of reserves for dual fuel peaking plants.

41. Combustion turbines like the proposed peaking plants are designed to provide operating reserves from an offline state, so for such units, the cost of providing operating reserves is generally much lower than the cost of generating electricity. Nonetheless, there are several factors that contribute to the cost of providing operating reserves. First, units scheduled for reserves in the day-ahead market face the risk of failing to start-up or having a forced outage, which can drive up real-time prices while causing the unit to buy out of its reserve obligation in the real-time market.

42. Second, units scheduled for reserves in the day-ahead market must be capable of starting-up suddenly if needed in real-time. Such units must have arranged for fuel or be capable of obtaining fuel on very short notice. While this cost can be substantial for gas-only units under tight gas system conditions, dual fuel units with onsite oil storage can be available without incurring an additional cost due to the option to operate on oil if gas is uneconomic or difficult to obtain in real-time (if not acquired in advance).

43. Third, a unit scheduled for reserves has an opportunity cost of not providing energy if it could have received a positive margin on the sale of energy. In general, such opportunity costs are explicitly accounted for in NYISO's co-optimized energy and ancillary services market design, so generators do not normally need to include such opportunity costs in their reserve offers.

44. Overall, the cost of providing operating reserves is difficult to quantify because it depends on uncertain factors, such as the likelihood of experiencing a forced outage, the resulting price impact, fuel supply arrangement decisions, and the availability of operating on an alternative, onsite fuel source. To develop a reasonable estimate of such costs, it is helpful to review the actual offers of other similar units. Thus, I analyzed actual historical day-ahead reserve offers for gas-only and dual fuel quick start units in Load Zones J and K in

2019.[14] The average capacity-weighted reserve offer these units was $2.00/MWh during off-peak hours and $2.40/MWh in all hours. These averages were relatively stable over the year and did not vary substantially across months. While the day-ahead market for operating reserves is generally competitive, there is no market power mitigation for offers priced below $5/MWh. Consequently, the on-peak offer prices likely reflect some mark-up by generators that face reduced competitive pressure during hours when some peaking units are dispatched to provide energy rather than reserves. Thus, the average off-peak offer price of $2.00/MWh is likely to be a more accurate estimate of the costs of providing operating reserves from units similar to the proposed peaking plants.

VI. Conclusions

45. Based on the foregoing, I support NYISO's proposed methodology for estimating the net energy and ancillary services revenues of the proposed peaking plants. In particular, I recommend the Commission approve: (1) the NYISO's proposed gas cost assumptions for Load Zone C and Load Zone G (Rockland County); and (2) the assumed cost of providing operating reserves for dual fuel peaking plants.

46. This concludes my affidavit.

Respectfully submitted,

/s/ Pallas LeeVanSchaick
Pallas LeeVanSchaick, Ph.D.
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[14] We used hourly day-ahead offer data from units at five plants in Load Zones J and K that offered 10-Minute Non-Synchronized Reserves in 2019. One additional plant that offered reserves was excluded as an outlier as it consistently offered reserves at prices much higher than other plants regardless of fuel prices.