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August 24, 2020

VIA E-MAIL (rpatterson@nyiso.com; ztsmith@nyiso.com)

New York Independent System Operator, Inc.
10 Krey Boulevard
Rensselaer, New York

Re: NYISO 2021-2025 Demand Curve Reset Process
Comments on Consultants' Final Report and NYISO Staff Draft Recommendations

Dear Messrs. Patterson and Smith:

GenOn Bowline, LLC is the owner and operator of the Bowline generating facility, a large, dispatchable generating facility with no energy duration limitations located in NYISO Zone G in the Lower Hudson Valley. GenOn Energy Management, LLC serves as the NYISO market participant representing the Bowline generating facility in the NYISO market. GenOn Bowline, LLC and GenOn Energy Management, LLC are collectively referred to herein as "GenOn".

The Bowline generating facility is an important local resource in the Lower Hudson Valley that is scheduled and dispatched in crucial periods to address circumstances when the system is experiencing stressed conditions, increased demand, or other factors have occurred and it is dispatched to support system reliability. Capacity prices must adequately reflect the value of maintaining ongoing operations and investing necessary capital expenditures to ensure reliability and the ability to perform when scheduled to meet operating conditions on the NYISO system. GenOn has actively participated in the NYISO's 2021-2025 Demand Curve Reset Process ("DCRP") with a focus on the assumptions made, and results developed for, the proxy peaking plant and the resultant proposed 2021-2025 DCRP parameters and 2021-2022 Demand Curve for the G-J Zone.[1] GenOn has retained BTU Analytics ("BTU"), a consulting firm specializing in natural gas market physical flows, pricing and dynamics, to provide additional information about gas market fundamentals in the Lower Hudson Valley.[2]

[1] GenOn also has reviewed AGI's assumptions concerning its proposed change to the natural gas hub for Zone C, TGP Z4 200 Leg. As addressed in comments being submitted by Competitive Power Ventures ("CPV") contemporaneously herewith, this gas hub does not extend into New York and existing constraints between the TGP Z4 200 Leg and TGP Z5 prevent its gas from being delivered into New York. Thus, GenOn agrees with CPV's finding that the TGP Z4 200 Leg is not a reasonable designation for the gas hub for the proxy peaking plant in Zone C.

[2] *See* Appendix A, BTU Analytics, "Natural Gas Pricing and Deliverability for NYISO Load Zone G and C" (dated August 24, 2020). As established below, BTU Analytics ("BTU") has provided relevant supplemental information that goes beyond the information provided to stakeholders by AGI throughout this DCRP effort for NYISO Staff consideration in developing its Final Recommendations because it demonstrates flaws in AGI's assumptions.

GenOn agrees with, and supports the adoption of, many of the Consultants' recommendations set forth in its Final Report which were also adopted by NYISO Staff in its presentation delineating its Draft Recommendations subject to two issues that remain under NYISO Staff review.[3] However, the gas hub AGI has chosen and the associated net energy and ancillary services revenues ("Net E&AS Revenues") that it has calculated for the proxy peaking plant in the G-J Zone are based on erroneous assumptions about natural gas availability that substantially overstate the energy margins that reasonably can be attributed to the G-J Zone proxy peaking plant due to both the structure of the NYISO's markets and broader gas market structural considerations, are contrary to AGI's past determinations without any material change in facts to support the changed position and fail to take into account bidding and other considerations that prevent generators from fully maximizing revenues in actual operations. Likewise, AGI has failed to take into account a substantial number of retirements that will occur in this reset period when calculating the adjustment factor for the level of excess capacity for this DCRP ("LOE-AF").

As the NYISO previously has recognized in its submission to FERC, one of the largest drivers of variable costs for peaking plants is fuel prices, and thus, "use of reasonable and representative fuel prices is critically important to the ability of the new EAS revenues model to produce appropriate and reasonable results."[4] GenOn agrees. When the full facts are weighed, it becomes apparent that the proposed 2021-2022 Demand Curve for the G-J Zone is not just and reasonable. In accordance with the timeline established by the NYISO for this 2021-2025 DCRP, GenOn appreciates this opportunity to provide these comments to address these errors and urges NYISO Staff to correct them in its Final Recommendations.

A. The Gas Hub Designation Must Be Changed and the Calculation of Net Energy and Ancillary Services Revenues for the Proxy Peaking Plant in the G-J Zone Must Be Revised to Account for the Bidding Dynamics Between the Gas and Electric Markets

Notwithstanding the facts that AGI expressly rejected designating TETCO M3 as the gas hub for the G-J Zone in the last DCRP and the system dynamics that have changed since that time only serve to further confirm its designation is not feasible, AGI has recommended that the benchmark price from deliveries on the TETCO-M3 pipeline be designated as the gas hub for the G-J Zone in its Final Report. AGI further asserts that the proxy peaking plant will be able to rely exclusively on interruptible gas transportation service ("IT") to deliver gas to the facility when it is committed for dispatch in the event

[3] At this juncture, the NYISO's consultants for this DCRP, Analysis Group, Inc ("AGI") and Burns and McDonnell ("BMD"), have issued their final interim report and NYISO Staff has issued its draft report containing its initial recommendations. Both documents were addressed at the August 10, 2020 ICAP meeting. Because AGI specified during the August 10th meeting that its report would only be revised to address the changes in the calculations once the final set of historic energy and ancillary services figures for the period September 1, 2017 through August 31, 2020 became available and confirmed no further substantive changes will be made to its report, the AGI/BMD report is referred to herein as the Final Report and the NYISO Staff's issuance is referred to herein as "Draft Recommendations."

[4] *See* FERC Docket ER17-386, *New York Independent System Operator, Inc.*, "Proposed ICAP Demand Curves for the 2017/2018 Capability Year and Parameters for Annual Updates for Capability Years 2018/2019, 2019/2020 and 2020/2021" (dated November 18, 2016) at 25.

system conditions are stressed and the gas system is constrained. AGI claims an adder of 27 cents per MMBtu ($0.27/MMBtu) is sufficient to secure this service during these constrained periods.

The NYISO's Services Tariff mandates that the Demand Curves in each Locality and for the New York Control Area ("NYCA") must be based on "the current localized levelized embedded cost of a peaking plant" in that respective region.[5] To identify the proxy peaking plant, the unit chosen must be economically viable.[6] It has long been established that a unit cannot be found viable if it cannot be constructed in the zone being evaluated or if its associated Net CONE that is being proposed cannot reasonably be expected to be replicated.[7] As established below, AGI's proposed gas hub and its perfect foresight approach for calculating the Net E&AS Revenues for the proxy peaking plant for the G-J Zone have produced a proxy peaking plant for the G-J Zone that is not viable. It, thus, cannot be just and reasonable. Given the importance of this variable as FERC has recognized,[8] GenOn urges NYISO Staff to designate the Algonquin pipeline as the gas hub for the G-J Zone and to apply a reasonable risk premium to adequately account for market uncertainty when calculating the Net E&AS Revenues for the proxy peaking plant in the G-J Zone. In deference to historical precedent, NYISO Staff could alternatively preserve the Iroquois Zn 2 pipeline index as the gas hub for the G-J Zone and apply a reasonable risk premium to adequately account for market uncertainty when calculating the Net E&AS Revenues for the proxy peaking plant in the G-J Zone. [9]

1. The Gas Hub Designation for the Proxy Peaking Plant in the G-J Zone Is Not Reasonable Because TETCO M3 Gas Is Generally Not Available to New York Suppliers and Suggesting IT Transportation Can Be Utilized To Avoid Firm Gas Transportation Charges To Receive "Discounted" Gas Demonstrates a Lack of Understanding Concerning Physical Gas Flows and Pipeline Availability Under Stressed Operating Conditions

In the Final Report, AGI summarily characterizes TETCO M3 as a "liquid trading hub which reasonably reflects the fuel cost of a generator such as the peaking plant that is expected to operate intermittently throughout the year."[10] AGI further notes that, because it changed the methodology it has used to apply its geographic criterion in this DCRP effort such that it now "assess[es] gas hubs for each

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[5] *See* NYISO Market Administration and Control Area Services Tariff ("Services Tariff"), § 5.14.1.2.1.

[6] *Id*.

[7] *See New York Independent System Operator, Inc*., 158 FERC ¶ 61,028 (2017) (hereinafter, "2017 DCR Order") at PP 27-29 (establishing NYISO's nearer-term ICAP market supports the need to confirm viability); *see also, id*. at PP 91-95, citing *New York Independent System Operator, Inc*., 146 FERC ¶ 61,043 (2014).

[8] *See* 2017 DCR Order at PP 119, 153 (footnote omitted) (noting NYISO's assertion that fuel prices are a major driver of the proxy peaking plant's variable costs and finding the natural gas hub selection for each locality must be reasonable to "ensure that the ICAP Demand Curves are set at appropriate levels to encourage investors to build resources as necessary to meet the reliability needs of the system.").

[9] Should NYISO Staff wish to place additional weight on the precedent criterion when balancing AGI's four-part criteria, Iroquios Zn2 remains a just and reasonable option for selection as the natural gas hub for the proxy peaking plant in the G-J Zone.

[10] *See* Final Report at 95.

location in Load Zone G separately," it was able to choose TETCO M3 for Rockland County and recommend it as the gas hub selection for the G-J Zone proxy plant.[11] NYISO Staff has initially supported this choice, characterizing it as the "best fit for market dynamics and geographic location."[12] Echoing its support for AGI's recommendation, Potomac Economics, the NYISO's external market monitoring unit ("MMU"), interprets certain categories of gas market information for 2019 and asserts its data demonstrates that any bottlenecks occur downstream, making the delivery of gas to suppliers in Zone G over the TETCO M3 pipeline a virtual certainty.[13] As demonstrated herein, AGI and the MMU have failed to fully assess the factors that markedly affect gas deliveries in the Lower Hudson Valley, and thus, their analyses are, at best, incomplete and their findings flawed.

The requirement to conduct periodic reviews to recognize advances in technology and system changes would occur over time was a core component of the Demand Curve proposal developed by NYISO stakeholders nearly two decades ago and is designed to ensure these changes were captured to produce the most efficient and cost effective capacity market pricing.[14] It is through this lens that the AGI proposed gas hub for the proxy peaking plant for the G-J Zone must be assessed.

This is not the first time the TETCO M3 pipeline was considered in this context for the G-J Zone. Implemented for the first time in the 2014-2016 DCRP cycle, defining the proxy peaking plant parameters for the G-J Zone has been undertaken three times. Reviewing the parameters considered for the 2013 DCRP, AGI rejected designating TETCO M3 in favor of Iroquois Zn2 based on geography and market dynamics in the 2016 DCRP.[15] While AGI has now "updated" its "methodology" for assessing the geography criterion and further finds TETCO M3 "reasonably reflects" the proxy peaking plant's fuel costs sufficient to meet the market dynamics criterion, its analysis on both counts fails. A more fulsome review of gas market dynamics irrefutably demonstrates that the conclusion AGI reached in the 2016 DCRP that TETCO M3 cannot meet the geography criterion continues to stand today. In fact, changes in system conditions since that time as reflected in publicly available information that is easily accessible and summarized in the appendix hereto provide irrefutable evidence that TETCO M3 cannot meet the geography criterion, and thus, is not a viable choice for the G-J Zone gas hub. It also remains a poor choice under the market dynamics criterion. Thus, designating TETCO M3 as the natural gas hub for the proxy peaking plant in the G-J Zone is not just and reasonable.

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[11] *Id.*, n.81 (further stating, "The 2016 DCR study assessed the selection of a single, representative gas hub for Load Zone G rather than evaluating the selection of representative gas hubs separately for the Dutchess County and Rockland County locations evaluated within Load Zone G. For this study, it was determined that TETCO M3 met the geography criterion for the Rockland County location, but did not meet this criterion for the Dutchess County location.").

[12] *See* NYISO Staff Draft Recommendations at 31.

[13] *See* MMU Comments on Initial DCR Report ("MMU Initial Comments") at 13-14.

[14] *See New York Independent System Operator, Inc.*, 103 FERC ¶ 61,201 (2003) at P61 (establishing "the Commission finds it reasonable to expect that the parameters may need adjustment over time," noting revisions will be developed with stakeholder input and emphasizing irrelevant or outdated parameters would be damaging to the NYISO's capacity market).

[15] For the 2013 DCRP, the NYISO retained a different consultant. AGI conducted the DCRP for the first time in the 2016 DCRP and introduced its four-part criteria to identify gas hubs at that time to assess potential gas hub options based on known selection considerations.

It is well-recognized that the Marcellus Shale gas build-out has had profound effects on natural gas deliveries in the Northeast since 2013. This development has directly shifted how and where gas is available in the Lower Hudson Valley beginning in 2016. With the ban on shale gas development in New York as well as, effectively, the moratorium on the development of new natural gas infrastructure, these effects are only becoming more pronounced over time.

TETCO M3 does not come into the Lower Hudson Valley. Rather, TETCO M3 market area gas supply is primarily used to serve Pennsylvania and some portions of New Jersey. As AGI and the MMU correctly recognize, delivery on the TETCO M3 pipeline ends in Northern New Jersey requiring transportation across another system. Specifically, at that point, the pipeline becomes part of the Algonquin system that runs not only across southeastern New York but also southern New England where it terminates in Boston.

Likewise, while the MMU correctly designates the amount of gas being delivered across the Algonquin pipeline and the limited restrictions on interruptible nominations sourced thereon from points west of the Stony Point Compressor Station, both AGI and the MMU fail to take the next -- and most critical step vis-à-vis ensuring the Demand Curves are set at adequate levels to maintain the reliability of the New York electric system in their analyses. Is this gas coming across the Algonquin pipeline available to the proxy peaking plant in the Lower Hudson Valley of the New York market? In off-peak periods (nights, weekends, and periods of moderate temperatures), perhaps. In the summer and winter when the proxy peaking plant is modeled as actually operating? No. As reflected in the publicly available information captured by BTU, the gas delivered across the Algonquin pipeline is almost entirely committed under firm transportation arrangements to the New England market.[16] Failing to capture this gas market dynamic is a critical mistake that fundamentally must eliminate TETCO M3 from consideration.

Equally flawed is AGI's premise that IT is the solution to the fact that TETCO M3 stops short of the New York border, particularly at the 27-cent level contained in the Final Report. The NYISO Services Tariff mandates that gas costs for the proxy peaking plant must include not only the applicable daily spot price of the supply itself but also "an adder *to account for any applicable transportation and delivery costs*.[17] To secure any of the gas being delivered under firm transportation contracts, the recipient must be willing to sell it. However, the shippers on the Algonquin pipeline are primarily composed of New England LDCs and utilities downstream of Rockland County that themselves have statutory obligations to serve their customers. It is, at best, fanciful to presume that these shippers would provide supply to the proxy peaking plant under the peak winter operating conditions when is more likely to be operated and most needed for NYISO system reliability. These utility shippers will not "strand" their own customers to support the proxy peaking plant at a price of M3 plus $0.27/MMBtu (or any price, really) during these periods thereby leaving the NYISO proxy peaking plant stranded and in a position that it must declare a forced outage due to lack of fuel. During stressed operating conditions, such an outcome could well trigger reliability implications that could otherwise have been avoided in this process.

For AGI's theory to thus be applied in the real world, the proxy peaking plant in the G-J Zone would have to lure this gas away from New England end users/shippers. However, even in those instances where

[16] *See* Appendix A at Slide 3.

[17] *See* NYISO Services Tariff, §5.14.1.2.2.2 (emphasis added).

this is possible, these shippers will have no reason whatsoever to make this gas available at the discounted level of the 27-cent adder proposed by AGI during peak winter periods. With demand likely to be very high, in the unlikely event that any gas is released by these shippers, it can only reasonably be assumed to become available at a price this is at least flat (and potentially, even, a premium) to the AGT Citygate price at which these marketers could deliver the natural gas further downstream.

Moreover, once the reality of the firm transportation contracts and the associated drivers and incentives thereunder is taken into account, very small amounts of gas are left over that could even be available on an IT basis. As reflected in the publicly available information attached hereto, dating back as far as 2016, IT has largely been – and continues to be -- unavailable in both the summer and winter periods.[18] For example, IT has not been available at all in Rockland County for a single day so far this summer. The same was true through all of 2019. Thus, while AGI has applied its TETCO plus 27-cent adder as the fuel cost for the proxy peaking plant in the Lower Hudson Valley and has calculated energy margins that are largely concentrated in the winter, those Net E&AS Revenues are illusory. No supplier in the Lower Hudson Valley will be able to access gas at those levels during these periods. In fact, electric prices cleared higher in these periods driven by increased gas costs borne by suppliers. Thus, firm transportation service must be considered if even available. Such service would come at a "take-or-pay" fixed cost under long-term contracts often required to extend 15 to 20 years from a facility's commercial operation date. This cost (along with associated collateral costs) must be built into the annual operating cost of the proxy peaking plant for its life to accurately reflect the gas costs it will bear.

Nor can AGI rely on the market dynamic criterion to support its TETCO M3 designation for the proxy peaking plant in the G-J Zone. In the 2016 DCRP, AGI rejected TETCO M3 because its pricing did not correlate well with LBMPs in Zone G. While Figure 16 in the Final Report shows a closer correlation last year than existed in 2016, this hub's correlation – even after taking into account the proposed 27-cent adder for transportation costs – on average over the historic period assessed remains the poorest when compared against other Northeast gas pricing points.[19]

As AGI has recognized in its Final Report and NYISO Staff has concurred, assumptions must be used that will produce adequate Demand Curves for units needed for reliability to be constructed and retained in each Locality.[20] When the factors that will affect the proxy peaking plant's ability to actually access gas supply and the associated costs it must bear to do so are fully taken into account, the TETCO

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[18] *See* Appendix A at Slides 5-7.

[19] *Id*. at Slide 11. BTU reviewed data for the period captured by historic prices for the 2021-2022 Demand Curves (*i.e.*, beginning in 2017). The 2019 data for TETCO M3 reflects a closer correlation than in prior years due to mild winter weather conditions. Under these circumstances, there is very little congestion and prices are able to converge more closely because they are connected. However, the proxy peaking plant is the unit needed for reliability, and thus, it is necessary to assess pricing dynamics over the three-year historic period to provide adequate data points that are reasonably expected to be reflective of system conditions.

[20] *See* Final Report at 29-30 (noting "selecting a plant without SCR emissions controls would not accommodate potential new plants throughout the region"). GenOn supports AGI's recognition that the facility that is modeled must be able to provide reliable service. By definition, the proxy peaking plant reflects the capacity that will be on the system when the system has very limited excess capacity and is effectively at the minimum installed reserve point. During periods when it is called upon to operate, it cannot be on a forced outage either due to emissions restrictions or lack of fuel. The costs included to calculate the plant's Net CONE must adequately take these factors into account.

M3 hub indisputably cannot meet the geography criterion. Likewise, it remains a poor choice when considering the market dynamics criterion. Thus, based on the foregoing, GenOn respectfully urges NYISO Staff to either designate the Algonquin pipeline or alternatively maintain Iroquois Zn2 as the gas hub for the G-J Zone proxy peaking plant, both of which constitute a just and reasonable selection.

2. Presuming a Proxy Peaking Plant Can Have "Perfect Foresight," and Thus, Can Maximize Its Net E&AS Revenues Produces a Net CONE for This Facility That Is Not Just and Reasonable

Separate and apart from its gas hub designation which cannot stand for the G-J Zone, AGI has adopted a methodology to calculate Net E&AS Revenues for the proxy peaking plant in the G-J Zone that presumes the plant had perfect foresight when being bid into the market, and therefore, can maximize these revenues in all hours, in all days and in all seasons (shoulder and peak including, most problematically, winter peak operating conditions) across all three years. Given that the proxy peaking plant in the G-J Zone is a dual-fueled facility that will run primarily on gas, the gas costs it faces are the most significant variable cost driver in determining the revenues it will secure from the energy market as AGI has previously also acknowledged. No stakeholder disputed that fact. Because AGI has failed to adequately account for the market and scheduling uncertainty faced by generators due, in large measure, to the mismatch between the electric and gas "days" exacerbated by the extended periods for which gas must be contracted to address gas purchases in all weekends and further by even longer holiday weekends, AGI's Net E&AS Revenue calculations are not reasonable.

As has been long documented, there are structural inefficiencies between when generator offers must be submitted to the NYISO to participate in the day-ahead market as required by the NYISO's Services Tariff and its Procedures and when gas can be purchased to support that operation. First, energy bids for the day-ahead market must be submitted by 5:00 am the day before the market day at issue. At that time, the generator owner cannot yet know its costs to purchase gas supply with certainty because gas trading in public markets normally takes place between 8:00 AM and 12:00 PM. While it is true that there may not be much gas price variability when generally considered on a day-by-day basis, there can be very significant pricing volatility between days during peak periods or when there are service or supply interruptions. It is simply not possible for *any* generator to fully anticipate these differentials all day every day. Further exacerbating this uncertainty is the fact that on days of extreme demand or days when major pipeline maintenance is being undertaken, gas trading can be considerably delayed which, standing alone, can lead to abnormal trading and pricing patterns. On these days, gas prices can be subject to more volatility but generators will have already submitted their offers into the NYISO day-ahead market and the market will have cleared based on prices that are not ultimately reflective of actual gas costs. The timing of bids into the NYISO day ahead market compels generators to submit offers that are a forecast of next day market prices for gas. Determining the gas costs it will include in its bids requires a careful balancing of several risk factors. If a generator submits energy offers using a gas price that is too high, the generator may not receive a day ahead award and will earn no energy margin for the day. On the other hand, if a generator submits offers based on gas prices that are too low, the generator may be unable to procure gas at that level thereby earning less energy margin and potentially facing energy margin losses for the day. AGI has failed to capture any of this uncertainty in its calculations.

It is further noteworthy that gas tends to trade to the upside of expectations during the winter periods due to the fact that there is simply a finite number of molecules available to be supplied, especially on pipelines that run through New York State to New England. As a general matter, New England tends to be colder than New York and concomitantly has higher demand for natural gas in heating applications. As explained above, the fact that firm transportation capacity on pipelines to New England is largely controlled by LDCs and utilities that will not sell or remarket capacity on days where demand is highest is a critical factor that must be taken into account as it substantially affects the ability (and, in fact, can lead to the inability) of generators to secure gas during stressed days if they do not have firm transportation contracts. During these periods, the economics of operating the proxy peaking plant are further compressed or, in some cases, can be entirely eliminated. AGI also did not capture these dynamics.

Second, over every weekend, natural gas must be purchased in weekend "packages" that usually span from Saturday at 10 am to Tuesday at 10 am. In contrast, the NYISO makes day-ahead awards in the electric markets on a day-by-day basis. Generators must thus purchase such weekend gas packages well before knowing whether they have day-ahead commitments for most of this period. Because holiday weekends are even longer, they breed additional uncertainty as the "package" that must be purchased incorporates the extra holiday period. Most often, this dynamic turns a three-day package into a four-day package and the Thanksgiving holiday often adds yet another day, exposing generators to a 5-day gas purchase.

Adding further complexity and uncertainty, gas prices are known for Sunday and Monday in advance of the daily offer deadlines that a generator must meet in the NYISO day ahead market. However, load changes that occur during the weekend period, *e.g.*, Sunday/weekend load versus Monday/weekday loads as well as weather changes, can cause the NYISO to procure varying levels of day-ahead capacity over the time frame covered by the weekend "package." Because generators are required to buy flat levels of gas across the weekend "package" while having no way of assuring a consistent day-ahead award from the NYISO market, a further mismatch results that cannot be avoided. Here, too, AGI made no adjustments to account for these sources of structural inefficiencies between the NYISO electric market and the gas markets.

Third, natural gas pipelines, especially constrained pipelines like AGT and Millennium and Iroquois Zone 2 serving the Lower Hudson Valley, often require end users to receive nominated gas on a flat, pro rata basis across the gas day (10am of a day to 10am of the next day which are across two different electric market days). The implications here for an electric generator are significant given the way that the NYISO dispatches facilities. With the exception of nuclear generators, most units follow load during the day operating at higher loads during the peaks and lower loads in the off-peaks/overnight periods. Natural gas units operating at higher loads burn more gas in an hour than when operating at lower loads. The pipelines often enforce this flat requirement by mandating that generators "overburning" must buy intra-day gas and generators "underburning" must sell intra-day gas. Pipelines are authorized by tariff to issue financial penalties and in extreme circumstances, disconnect service to specific users that do not follow pipeline directions regarding intraday balancing. Here again, AGI did not capture these dynamics in its analysis or its calculation of energy gross margin.

Based on the extensive experience of its personnel in the areas of trading in the electric and gas markets which spans more than a decade and has included a number of facilities in various locations throughout the State, GenOn believes AGI's Net E&AS Revenues are substantially overstated and no generator – proxy peaking plant or otherwise – can realistically secure, or reasonably be expected to achieve, these levels of revenues. NYISO Staff has the information necessary to confirm whether the issues highlighted herein have been adequately addressed in the AGI model. Given the importance of these calculations which will play a major role in defining market prices for the next four-year period, NYISO Staff should confirm if the Net E&AS Revenues AGI has calculated for this DCRP adequately take into account the risk factors highlighted herein, produce revenues that a proxy peaking plant could actually be expected to earn and, thus, are, in fact, reasonable as AGI has asserted and, if not, should adjust the revenue calculations accordingly. [21]

B. The LOE-AF Calculation Must Be Adjusted To Account for the Identified Retirement of Certain Peaking Plants in Accordance with the DEC Peaker Rule

During stakeholder discussions, a number of parties highlighted the fact that -- unlike past efforts -- the base case assumptions to calculate the LOE-AF, had not been revised to incorporate updated information concerning the addition and retirement of certain facilities or the surrender of CRIS rights. In its July 23, 2020 presentation, AGI acknowledged this deficiency and identified the specific resource modifications that were made which resulted in a net 992.5 MW reduction in capacity.[22] AGI has incorporated these changes, and the resultant impacts on the 2021-2022 Demand Curves, in its Final Report. GenOn supports these revisions.

However, AGI has failed to account for the known retirement of an entire subset of resources, the peaking units in New York City and Long Island subject to DEC's recently implemented Peaker Rule.[23] As established in the compliance plans addressed by the NYISO as part of its 2020 Reliability Needs Assessment ("2020 RNA") work, a substantial amount of generation in these two areas will be retired in 2023 to comply with the Peaker Rule.[24] The NYISO's RNA results further establish that the retirement of

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[21] It bears note that AGI's perfect foresight assumptions were also called into question during the stakeholder process as applied to the Net E&AS Revenues that reasonably could be earned by storage resources. As reflected in the Final Report, AGI ultimately included a risk premium in this set of calculations to reflect the fact that perfect foresight by these suppliers is not reasonably attainable. (*See* Final Report at 86-87.) While the nature of the risk between a fossil fueled operator and an operator of an energy storage resource differs, both resources bear significant forms of risk that bar their ability to maximize revenues assisted by the vantage point of perfect foresight. AGI correctly modified its assumptions as applied to energy storage resources and, under the same basic rationale, NYISO Staff should make a similar accommodation for the proxy peaking plant.

[22] *See* Analysis Group, "NYISO 2019/2020 ICAP Demand Curve Reset: Draft Report Feedback" (dated July 22, 2020) at 25, 29, available at https://www.nyiso.com/documents/20142/13960166/Analysis%20Group%20Demand%20Curve%20Reset%20Draft%20Report%20Feedback.pdf/12703764-f3fd-b11c-fa24-24a4df1fd15b.

[23] *See* New York Department of Environmental Conservation ("New York DEC"), Ozone Season Oxides of Nitrogen (NOx) Emission Limits for Simple Cycle and Regenerative Combustion Turbines, 6 NYCRR Subpart 227-3 (2019) (hereinafter, "Peaker Rule").

[24] *See* New York Independent System Operator, Inc., "2020 RNA Preliminary ("1st Pass") Reliability Needs" (dated June 19, 2020) (finding reliability needs resulting from the retirement of a small number of peaking units), available at https://www.nyiso.com/documents/20142/13200831/02%202020RNA_1stPassRN.pdf/8a0de336-bd24-1260-dc4b-5df58cdb049f ; *see also* New York Independent System Operator, Inc., "2020 RNA Base Case Updates" at 4 (dated July 23, 2020), available at

a relatively small amount of this capacity will cause reliability needs.[25] The rest of this capacity will be permitted to leave the system. There is, thus, no basis to presume the continued operation of those units that will be permitted to leave the system beginning in 2023.

In its Draft Recommendations, NYISO Staff indicated that it was continuing to evaluate AGI's LOE-AF recommendations.[26] While GenOn agrees that the MWs that have been identified by the NYISO as triggering a reliability need should not be considered as retired facilities, the retirement of the vast majority of these resources does not produce any reliability needs. These facilities cannot be operated to meet the stricter emissions requirements that will be put into place in 2023. By law, these facilities must thus be retrofitted or repowered to meet more stringent emissions limits or they must be retired by 2023. Presumably given their age and the associated retrofit costs, their owners have established these facilities will be retired in their compliance plans. Given their decisions, over 1,000 MW of incremental retirements must be captured in the LOE-AF calculations. Thus, GenOn urges NYISO Staff to update the LOE-AF calculations to account for these retirements and produce revised 2021-2022 Demand Curves in its Final Recommendations.

C. Conclusion

For the foregoing reasons, GenOn urges NYISO Staff to recommend the changes to the parameters used for the proxy peaking plant in the G-J Zone as set forth herein to produce ICAP Demand Curves in the G-J Zone for the 2021-2025 DCRP that are just and reasonable.

Very truly yours,

Jonathan Sacks
Vice President
GenOn Energy Management, LLC and
GenOn Bowline, LLC

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https://www.nyiso.com/documents/20142/14027657/04%20RNA_2ndPassAssumptions.pdf/99ed227a-7208-8cf8-5eb3-891f324ca354 (finding post-1st Pass resource changes did not reduce or eliminate any of the identified 1st Pass reliability needs).

[25] *Id*.

[26] *See* New York Independent System Operator, Inc., "2021-2025 ICAP Demand Curve Reset: NYISO Staff Draft Recommendations" (dated August 10, 2020) at 7.

APPENDIX A

Natural Gas Pricing and Deliverability for NYISO Load Zone G and C

For Submission in NYISO 2021-2025 ICAP Demand Curve Reset Process

Prepared for:
GenOn Bowline, LLC and GenOn Energy Management, LLC.

August 24, 2020

www.btuanalytics.com
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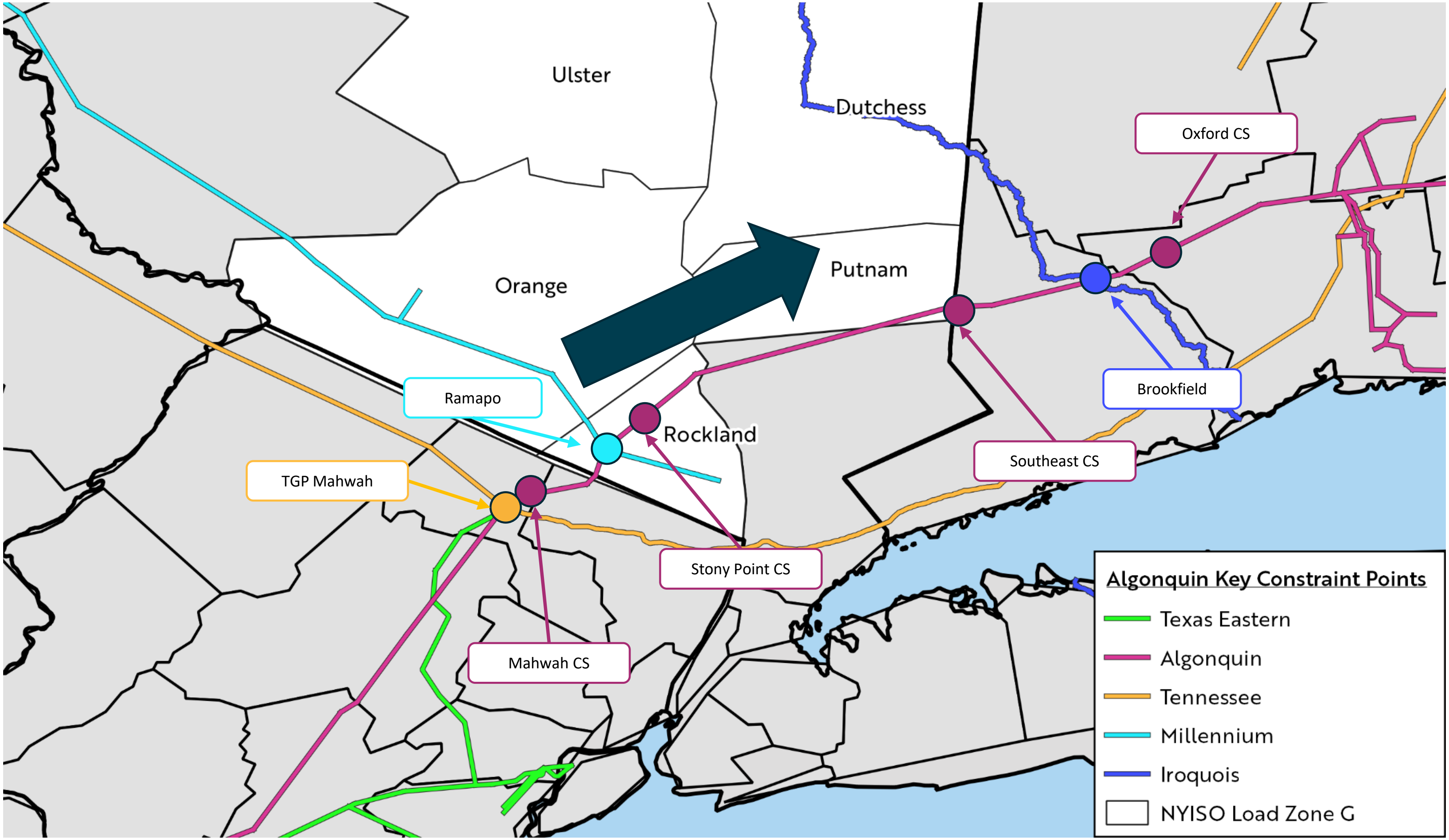
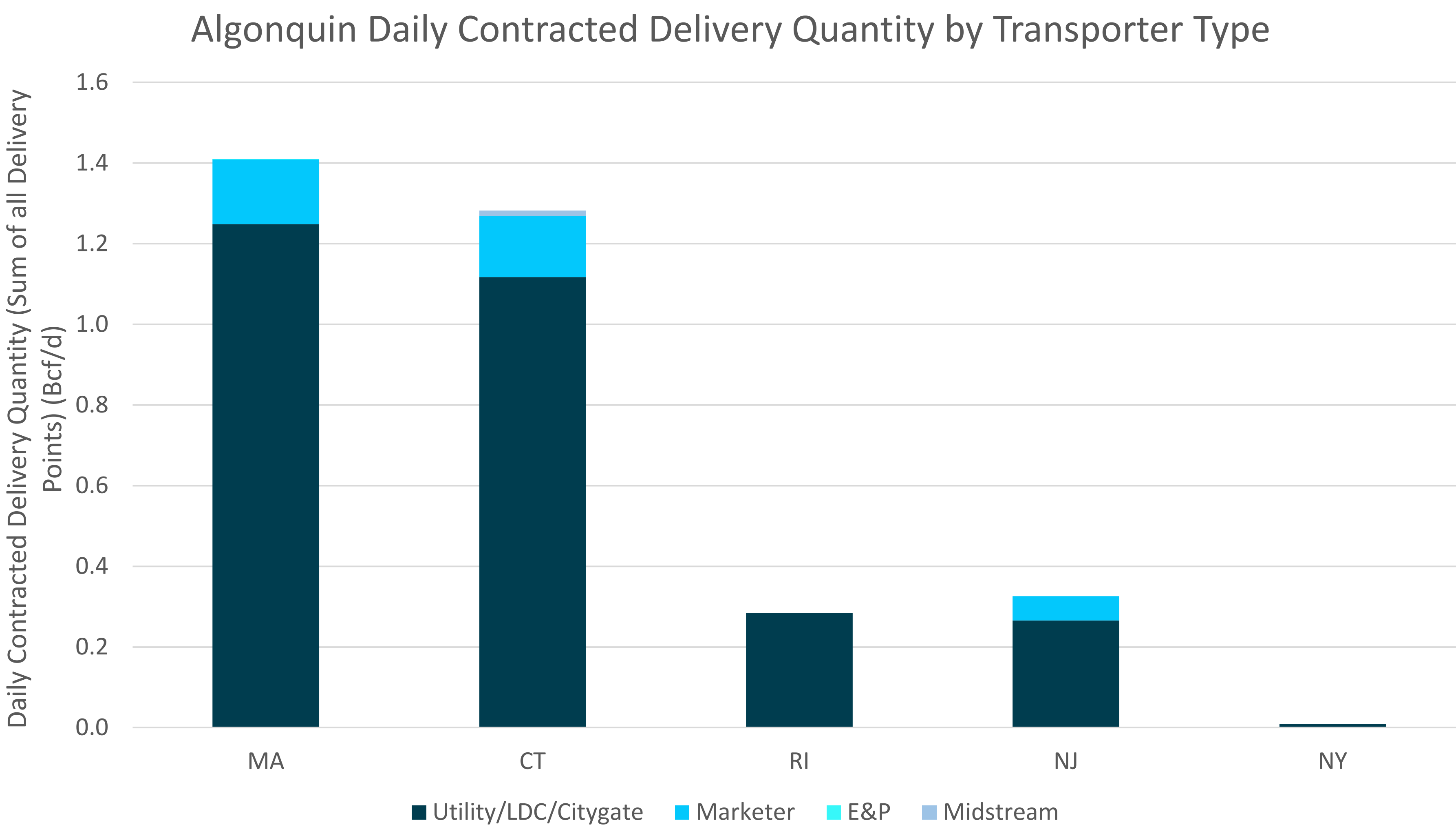
NYISO operations view of how Algonquin pipeline flows work is accurate for an assessment of AGT operations up to 2016, not beyond



Source: BTU Analytics

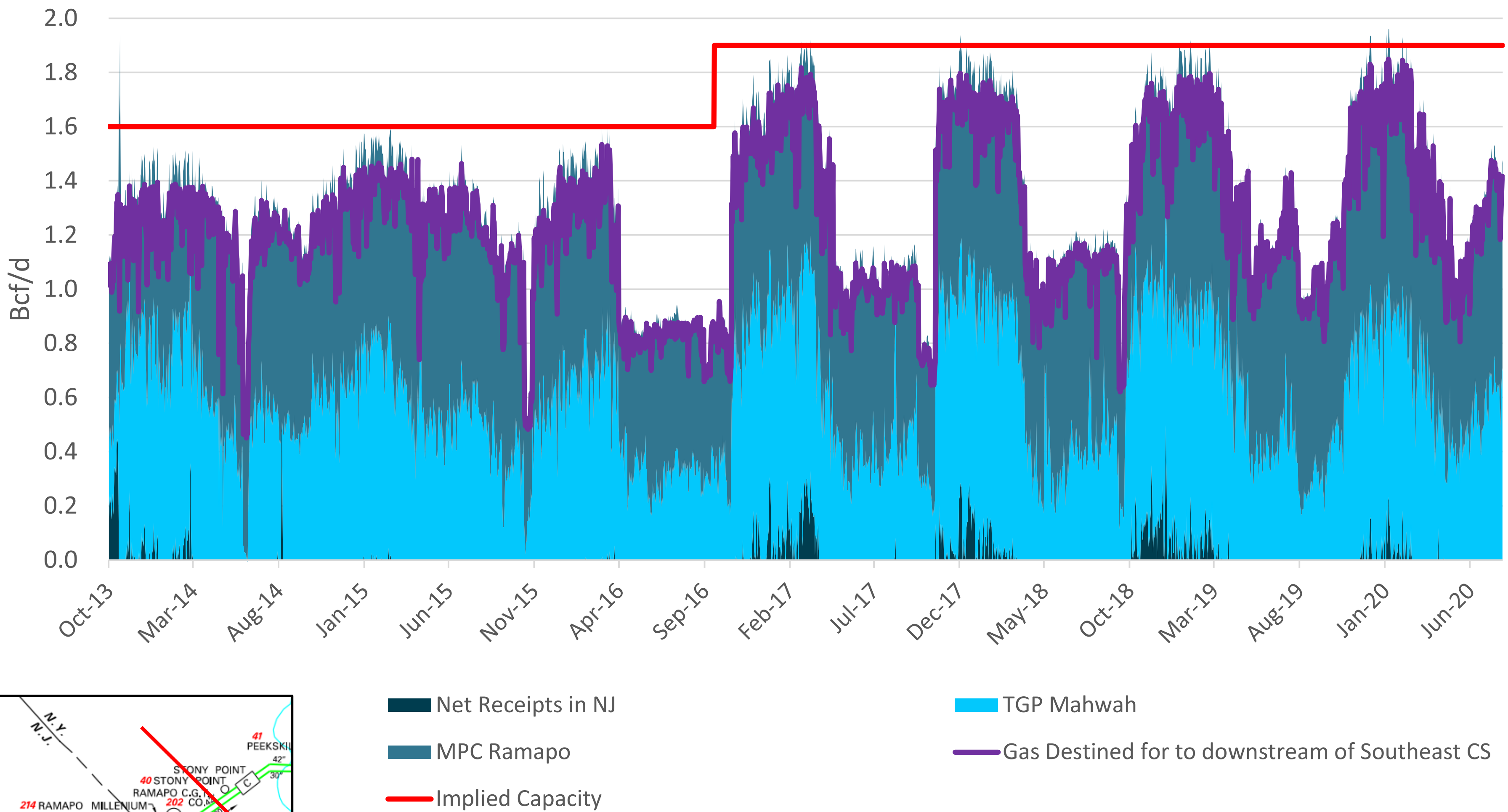
Algonquin FT volumes by state by type as of April 2020. NY shippers hold 0.3% of FT deliveries directly. LDCs in New England and New Jersey hold 88% of FT on AGT and LDCs seek to manage risk, not profit, and will not release FT to free-up IT in winter during peak operating conditions

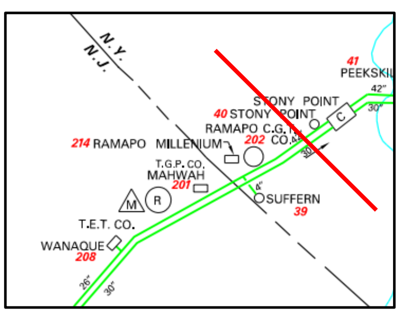


Note: Daily delivery quantity is a sum of all maximum daily point quantities for all delivery points in each state for each transporter type
Source: BTU Analytics, Algonquin informational postings

In winter only, very small volumes of gas flows from TETCO M3 (see net receipts in NJ volumes in dark blue below) and make it on to AGT. Asserting gas can be sourced from TETCO M3 ignores physical gas flows; when M3 gas does flow to AGT, it is in the heart of winter when all FT is being used to transport gas on AGT to New England. Incremental NY deliveries must compete at an Algonquin Citygate price.

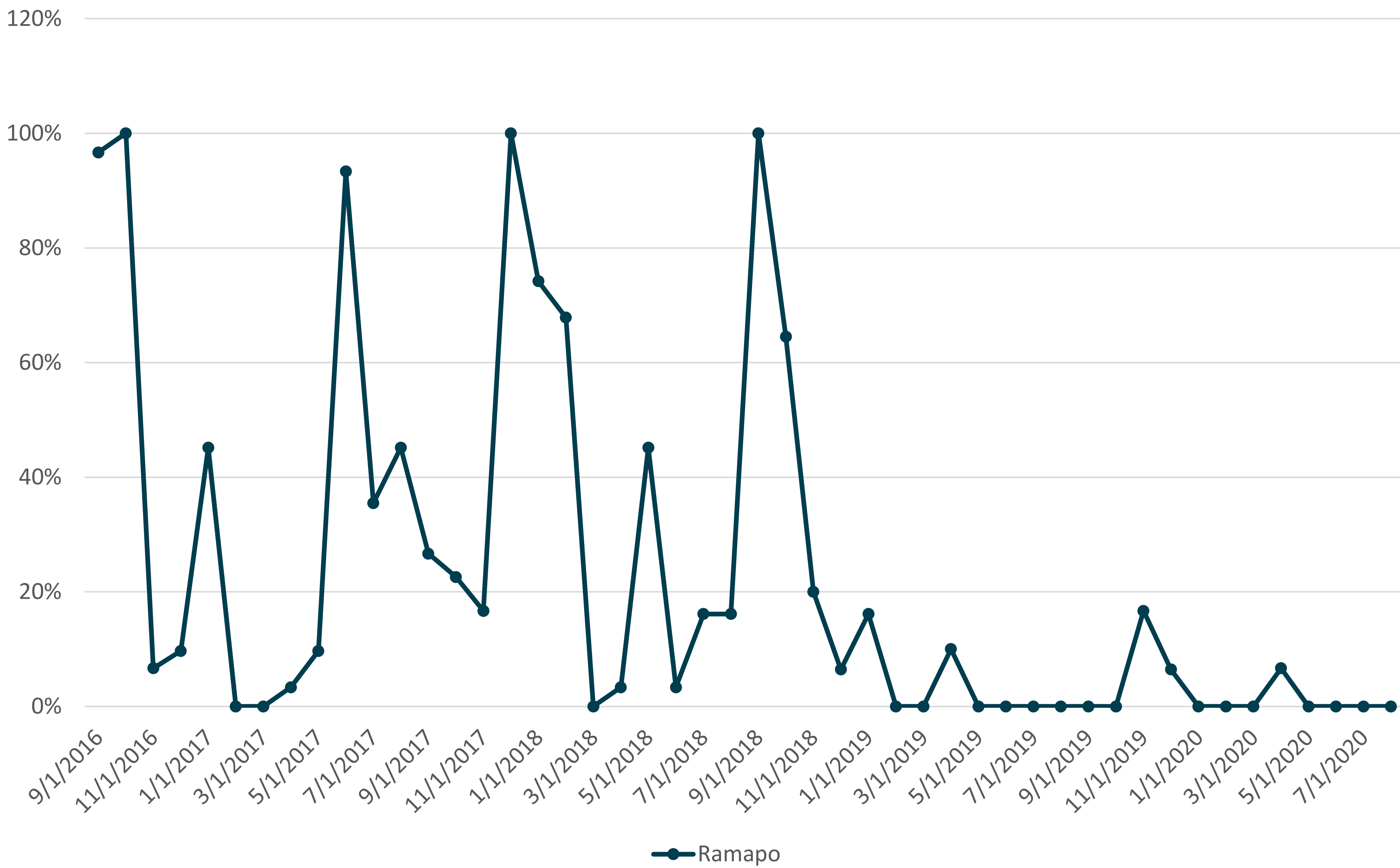
Flows East of Ramapo Interconnect





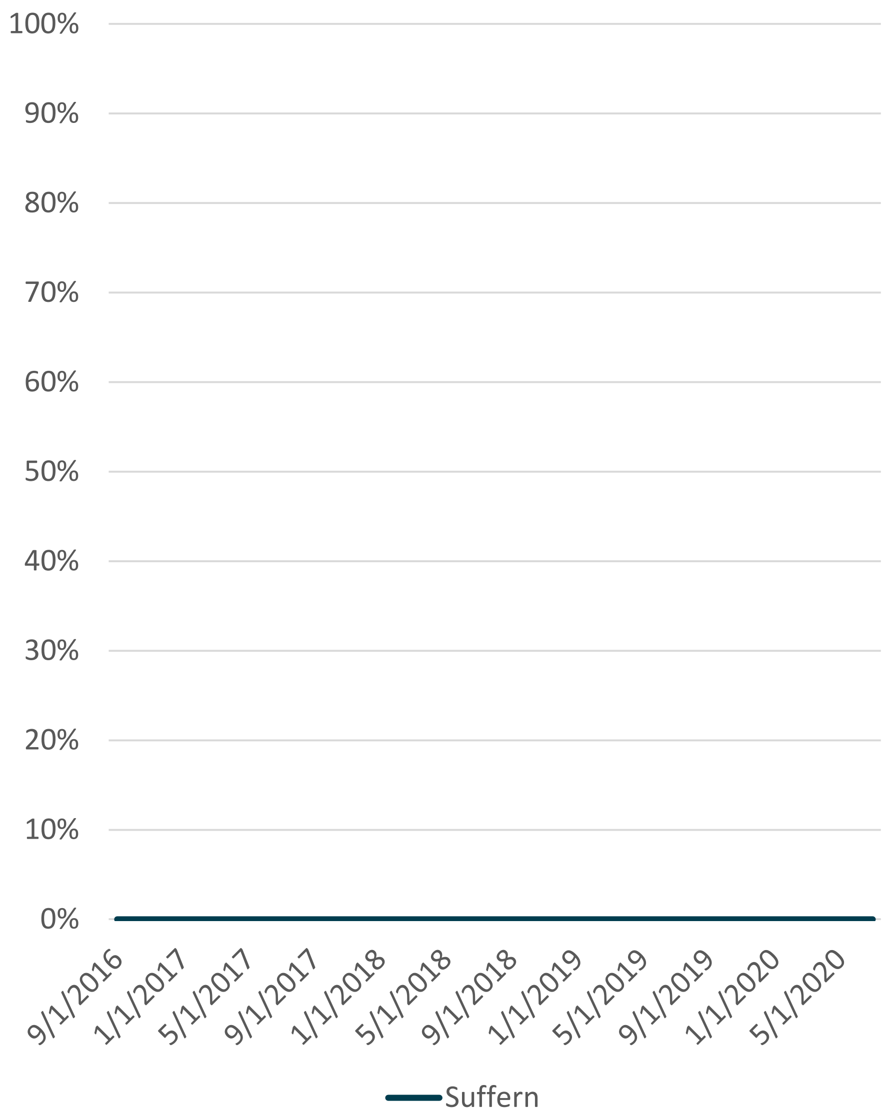
Note: Other includes flows moving northeast on Algonquin that originate west of the Mahwah interconnect with TGP.
Source: BTU Analytics. Data as of August 12, 2020

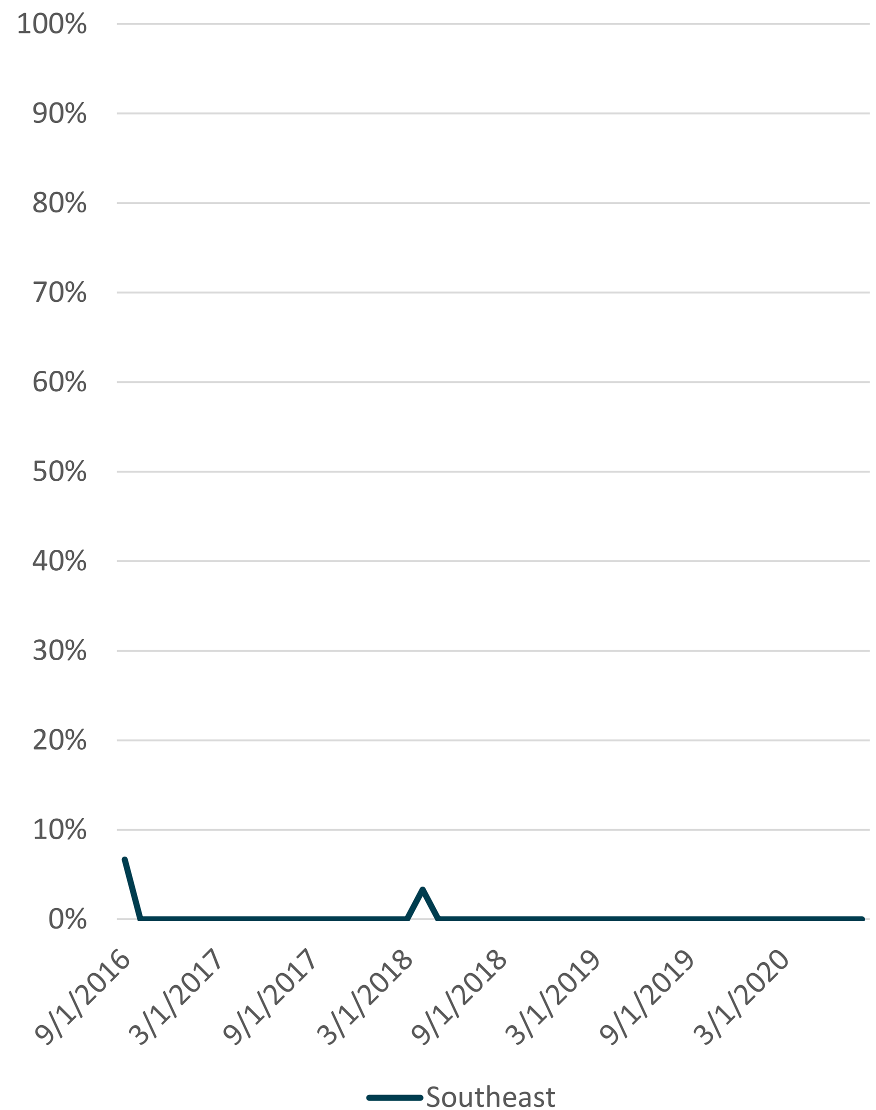
Interruptible at AGT Ramapo scarce since Q1 2019 - AGT daily interruptible percentage on a daily basis per month at the Ramapo MPC-AGT interconnect in NY



Note: AGT pipeline nominations scraped on 8/14/20 for IT flag
Source: BTU Analytics, Enbridge EBB. Updated August 14, 2020

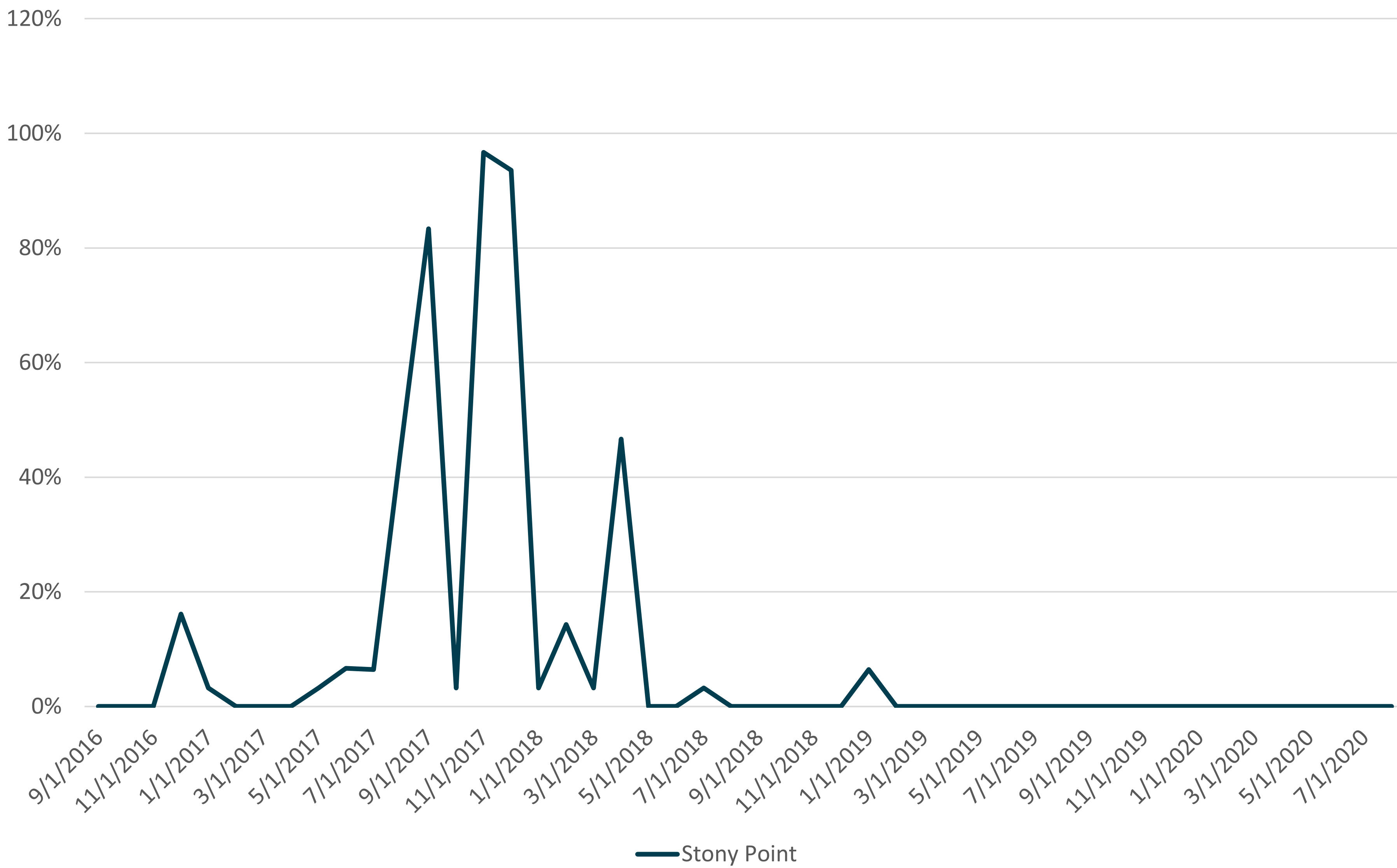
AGT daily interruptible *not available at all* for LDC in Rockland county where the modeled NYISO plant would be located - percentage on a daily basis per month at the Suffern LDC in Rockland County NY and Southeast LDC in Putnam County NY





Note: AGT pipeline nominations scraped on 8/14/20 for IT flag
Source: BTU Analytics, Enbridge EBB. Updated August 14, 2020

AGT daily interruptible not available for LDC in Rockland county since Q1 2019 - AGT daily interruptible percentage on a daily basis per month at the Stony Point LDC in NY



Note: AGT pipeline nominations scraped on 8/14/20 for IT flag
Source: BTU Analytics, Enbridge EBB. Updated August 14, 2020

Regional gas pipeline flow dynamics

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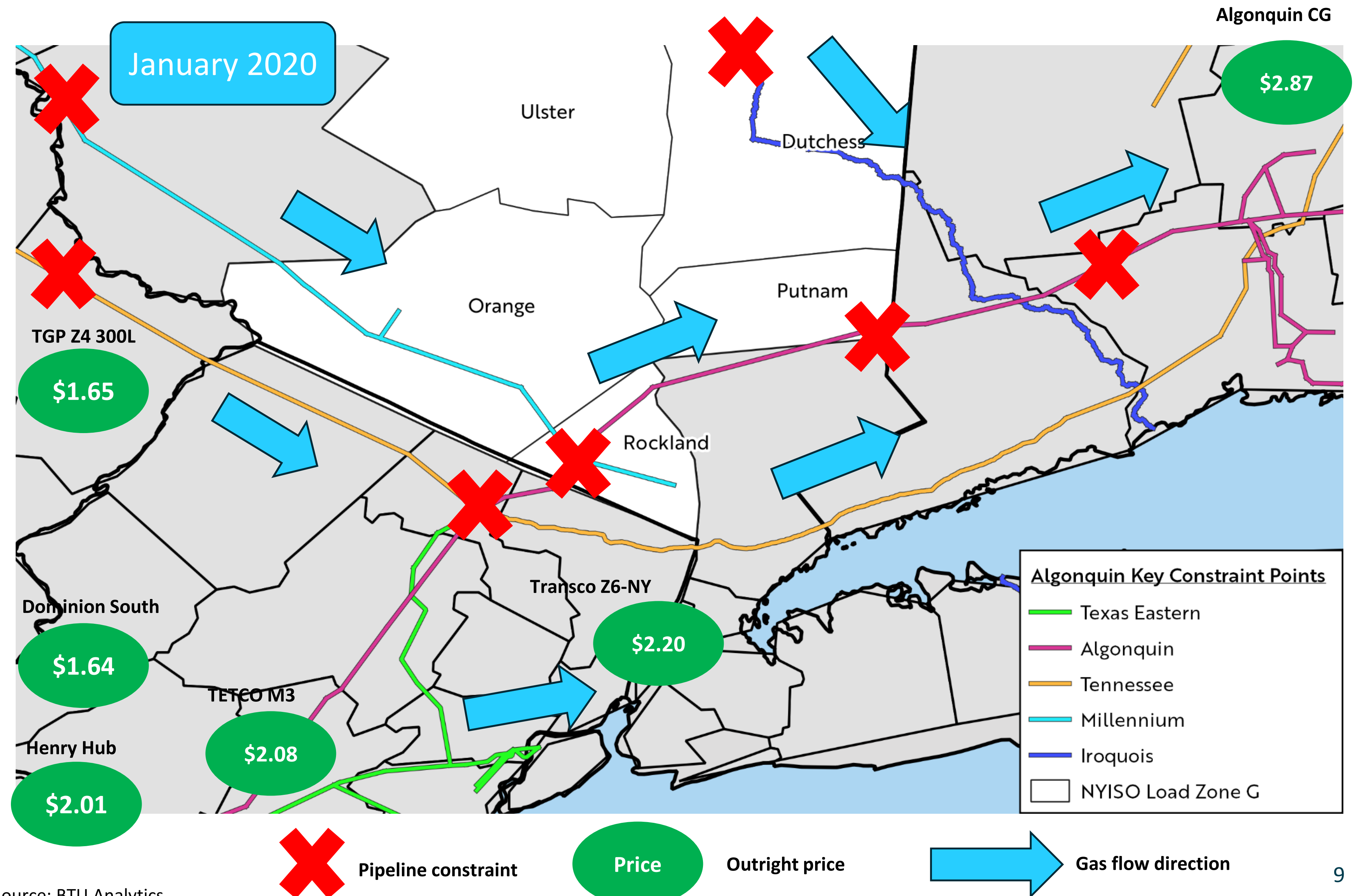
info@btuanalytics.com

Appalachia production and storage withdrawals in western Pennsylvania combined with peak winter demand in NJ, NY and New England mean there are widespread constraints through out Appalachia, NJ, NY and New England – AGT Southeast Compressor is NOT the only constraint of concern



Source: BTU Analytics

NYISO Consultant's Criteria

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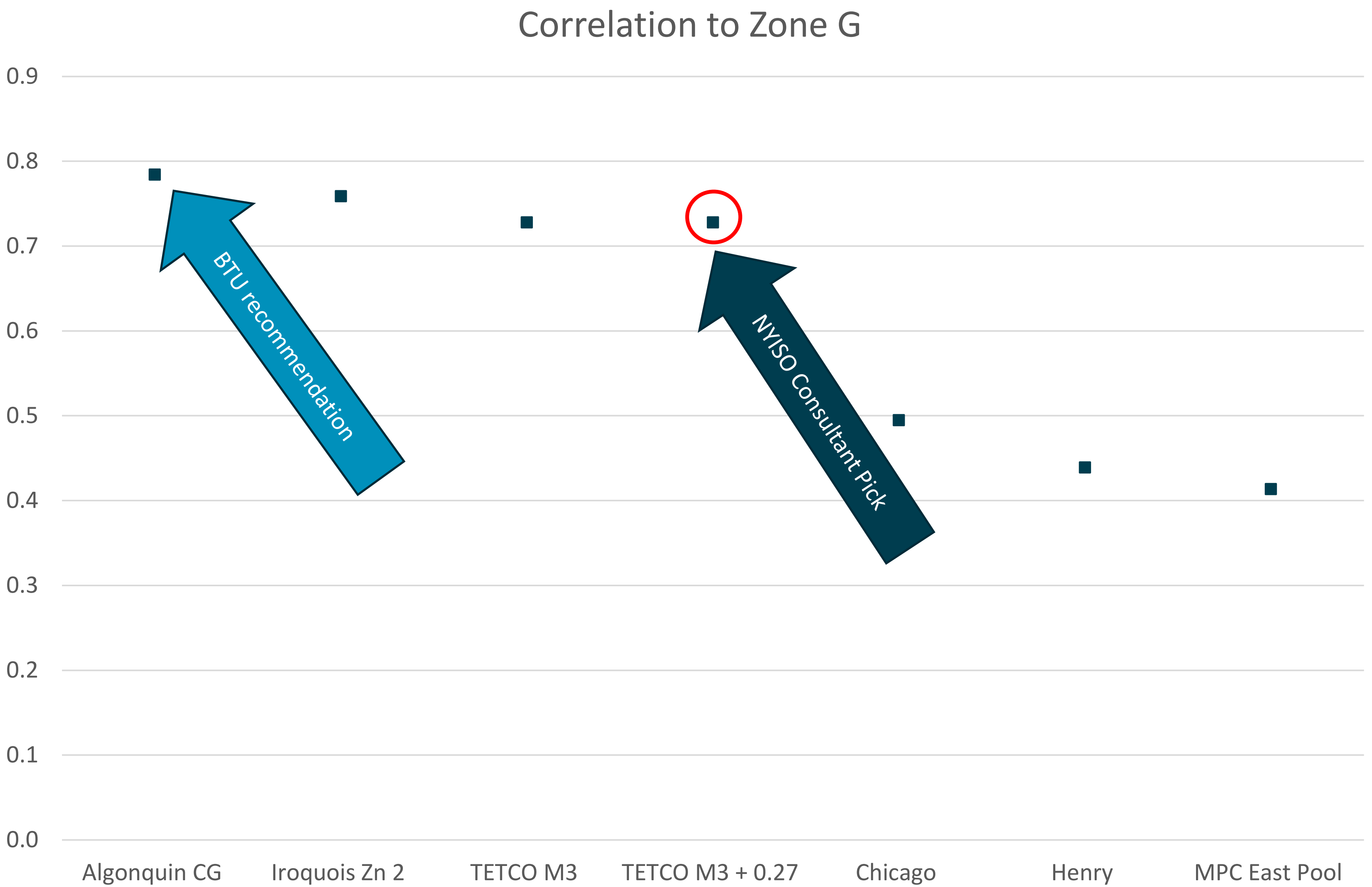
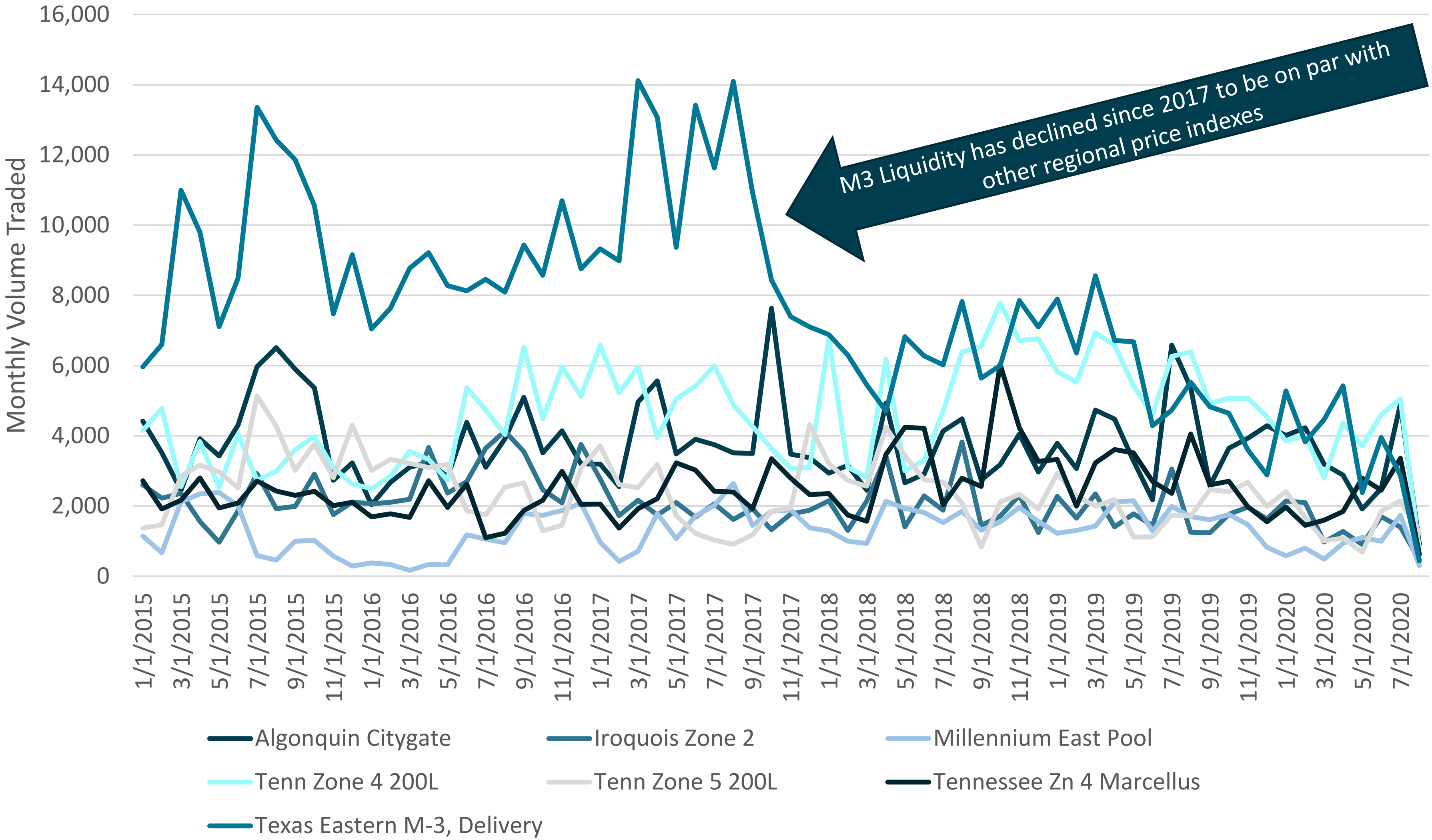
Market Dynamics: Northeast gas pricing point vs. NYISO LBMP pricing show consultant's picks based of correlation were third best picks based on this analysis



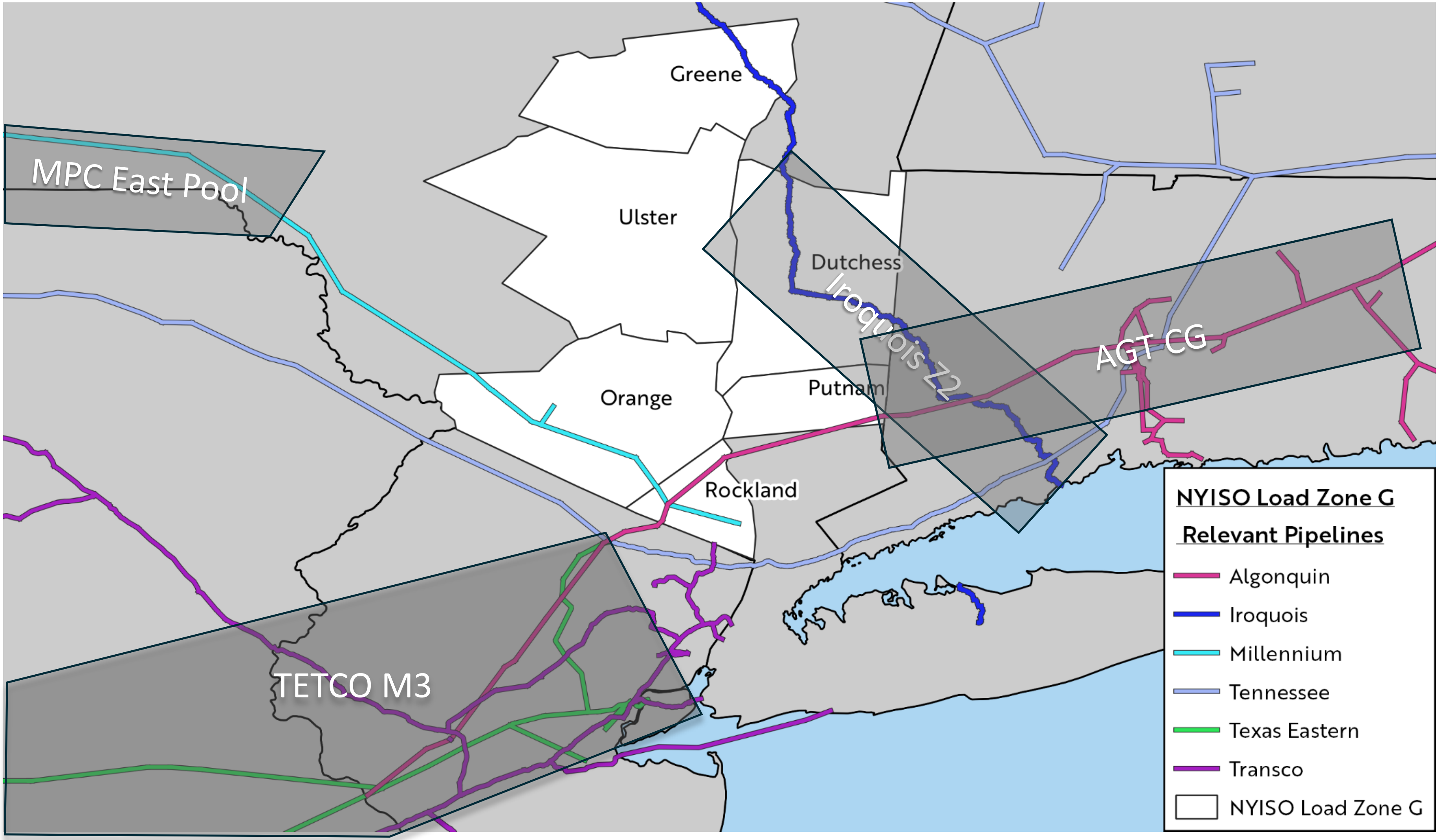
Source: BTU Analytics, NGI and NYISO – daily prices since Jan 1, 2017

Liquidity: Northeast gas pricing points volumes on monthly basis – all points are liquid



Note: Volume traded represents volumes traded on ICE as reported by NGI
Source: BTU Analytics, NGI Data as of August 13, 2020

Geography: NYISO Load Zone G to TETCO M3 is not a valid geographic match and ignores Algonquin and Iroquois deliver gas in Load Zone G (while TETCO M3 does not and both have stronger gas market/LBMP correlation)



Note: Millennium East Pool (MPC East Pool) pricing for receipts in Broome County NY
Source: BTU Analytics