Memorandum

TO: Analysis Group, Burns & McDonnell

FROM: David Patton, Pallas LeeVanSchaick

DATE: August 24, 2020

RE: MMU Comments on Independent Consultant Interim Final Draft ICAP Demand Curve Reset Report and NYISO Staff DCR Draft Recommendations

In accordance with MST 5.14.1.2, the NYISO periodically conducts the ICAP Demand Curve reset ("DCR") process to ensure that the capacity demand curves are set at levels that provide efficient incentives for market based entry that satisfies the NYISO's resource adequacy needs. The NYISO contracted with the Analysis Group and Burns & McDonnell ("the consultants") to perform a study to set the levels of the capacity demand curves in each of the four capacity localities. The consultants provided their Draft DCR Report on June 5, 2020, entitled *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Initial Draft Report* ("Initial Draft Report").

The consultants also proposed certain adjustments to their initial recommendations in response to feedback received on the draft report. These adjustments were discussed at the July 22, 2020 Installed Capacity Working Group ("ICAPWG") meeting and are accounted for herein. NYISO staff issued a report on August 5, 2020 that discusses its proposed demand curves. A revised consultants' report (the "Interim Final Draft Report") was also issued on August 5, 2020. An updated final version of the consultants' report along with NYISO staff's final recommendations will be issued in September 2020.

As the Market Monitoring Unit for the NYISO, Potomac Economics is obliged to review and comment on the independent consultants' report in accordance with Market Services Tariff section 5.14.1.2.2. Throughout the process, we have provided verbal and written feedback to the independent consultants as they developed their draft recommendations in consultation with the NYISO and stakeholders.

We generally support the consultants' methodology and recommendations. However, we identified two assumptions that should be revised because they are not supported by market data or reasonable economic considerations. Both assumptions work to inflate the net cost of new entry ("Net CONE") underlying the capacity demand curves. This is particularly harmful at this time given that NYISO is substantially over supplied and inefficiently high demand curves will serve to impede efficient retirements and perpetuate the current capacity surpluses. Therefore, we recommend the following changes:

- Cost of Debt – Revise downward the cost of debt based on a broader view of the available data that does not over-emphasize the recent COVID-19-related financial market turbulence. This would support a value in the range of 6.0 to 6.5 percent rather than the proposed value of 6.7 percent.
- Amortization Period – Use an amortization period of 20 years rather than 17 years. The 17-year assumption is unreasonably low and ignores publicly available information on how the power system will adapt to the zero-emission provision of the Climate Leadership and Community Protection Act ("CLCPA").

Table 1 summarizes our estimated impact on the annual ICAP reference values (or Net CONE) of each recommendation. The impacts shown in this table are cumulative.

Table 1: Estimated Impact of Proposed Changes on Annual ICAP Reference Value

Issue	Approx. Net CONE Impact ($/kW-year)			
	Zone C	Zone G-Rockland	Zone J	Zone K
Cost of Debt (6.25%)	$1.2	$1.4	$1.8	$1.7
+ Amortization Period	$5.2	$7.4	$5.9	$7.5
Total	**$6.4**	**$8.8**	**$7.7**	**$9.2**

We also recommend the consultants consider modifying the following assumption to ensure that the net revenue estimate of the Zone C unit is not overstated:

- For the cost of gas for the Zone C unit, continue to use the TGP Z4 (200L) index plus $0.27/MMBtu for April through November, but replace this index with the Niagara gas index in the months of December through March.

In addition to these changes, we also discuss our support for several of the consultants' recommendations, including:

- Assuming a cost of $2/MWh for selling operating reserves for dual-fueled units. Compared to the previous assumption, this will more accurately reflect the fuel reservation costs of reserve providers in New York with oil backup that would not likely incur large gas procurement costs when selling reserves.
- Setting the NYCA demand curve based on the Load Zone C peaking plant, since this unit is expected to be deliverable in Rest of State (i.e., Load Zones A to F).
- Using the TETCO M3 index plus $0.27/MMBtu for the cost of gas in Load Zone G for the Rockland County unit.

A. Impact of COVID-19 on Cost of Debt

In March 2020, the consultants provided an initial recommendation of 6.1 percent for the cost of debt assumption. This was based on recent debt issuances by independent power producers over the last 3 years and variations in bond yields for comparably rated debt for one year through February 2020. The consultants raised the cost of debt to 7.7 percent in the Initial Draft Report to reflect the financial market impacts of the COVID-19 pandemic. These effects proved to be transitory and the consultants subsequently revised it to 6.7 percent. We recommend relying on long-term historical data over at least one year or more, which would support a cost of debt between 6.0 and 6.5 percent.

The consultants are right to consider information from recent months, but it should not be given excessive weight. Borrowing costs over the next four years are not likely to resemble the recent elevated rates. Developers of new generators with long project timelines have control over the timing of their investment and would avoid issuing debt during brief periods of market turbulence. The use of an upwardly biased cost of debt would result in an overestimated Net CONE and higher capacity prices than necessary.

Market conditions have changed considerably since the consultants developed their initial recommendation. Figure 1 shows the Single-B US High Yield Index Effective Yield from the Federal Reserve Bank of St. Louis for the year from August 20, 2019 through August 20, 2020.

Figure 1: B-Rated Bond Yield, August 2019 to August 2020

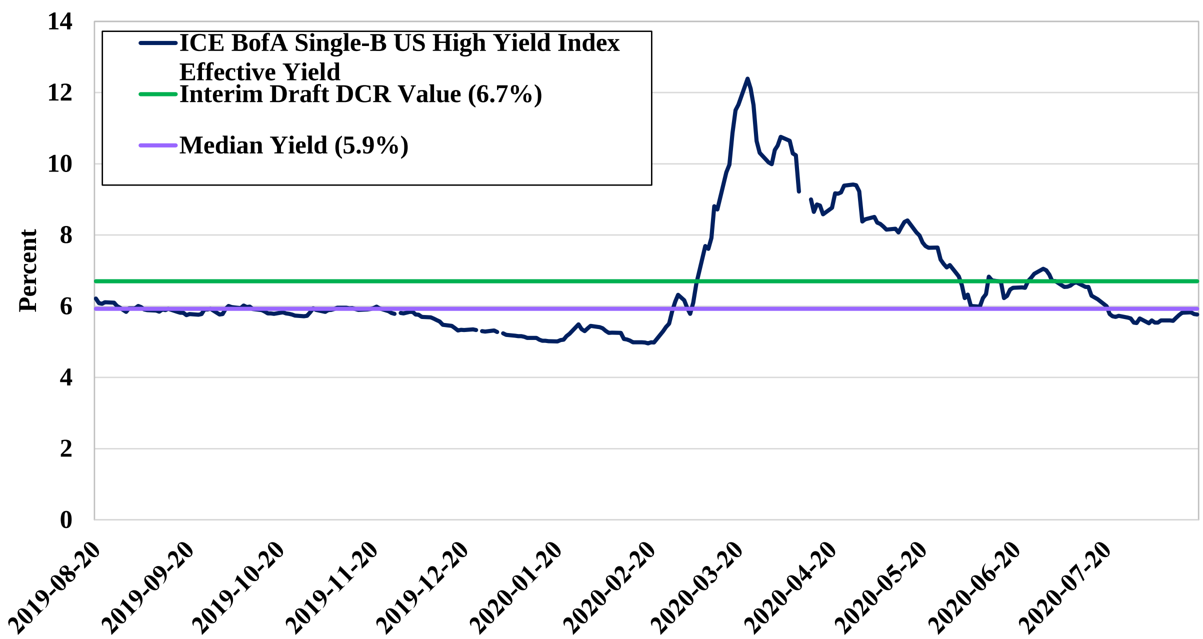


Figure 1 shows that yields began to rise sharply in late February and remained elevated in April and May. These substantial increases reflected severe liquidity issues in the credit markets that have not been sustained. When presenting their rationale for a higher cost of debt in May 2020, the consultants pointed to the sharp increase in debt costs that occurred between March and April. In particular, the consultants highlighted costs of B-rated debt at 12.4 percent on March 23 and 9.3 percent in the week of April 21.[1] Since May, Figure 1 shows that the B-rated corporate debt benchmark has fallen considerably.[2] Yields then fell close to pre-COVID-19 levels in June and fell below 6 percent in August.

The purpose of this analysis is not to suggest that only the most recent yields during August 2020 should be used. Rather, it is to highlight that recent trends should provide grounds for extreme caution in considering how debt yields during a two-month period this year will relate to the cost of borrowing for the entirety of the 2021-2025 demand curve reset period. A principled approach to establishing all demand curve parameters is to seek values that reflect a reasonable expectation of the parameter over the reset period. Such an approach to calculating the cost of debt (e.g., a rule-based method such as using the median over a significant period of time) will avoid giving undue weight to short-term market fluctuations.

It is typical in utility ratemaking to consider long-term data on market indicators. Table 2 below shows median B-rated bond yields over a period of one, two, three, four or five years through August 20, 2020.

Table 2: Median B-Rated Bond Yield Historical Median Daily Values

Period	Median Yield (%)
August 2019 - August 2020	5.93
August 2018 - August 2020	6.45
August 2017 - August 2020	6.35
August 2016 - August 2020	6.21
August 2015 - August 2020	6.39
Interim Final Draft Report	6.70

While the 6.7 percent cost of debt recommended by the consultants in their Interim Final Draft Report is more reasonable than the 7.7 percent draft recommendation, it is still significantly above what a historical review of benchmark rates would support. Median yields over the historical periods shown in Table 2 are consistent with our recommendation to assume a cost of debt between 6.0 and 6.5 percent. It is appropriate for the historical costs used to establish this assumption to include data since the onset of COVID-19, but not to assign it disproportionate weight to this period. In fact, given that current yields are below 6.0 percent, it would be most reasonable to assume a cost of debt at the low end of this recommended range.

1 See Analysis Group presentation to Installed Capacity Working Group on May 19, 2020.

2 The four power companies with meaningful ownership of merchant generation examined by the consultants issued debt in the past three years with ratings that were mostly B and better (BB and BBB-). The use of B-rated bond yields as a benchmark for examining cost of debt is therefore reasonable. Calpine Corp issued debt with B and BB ratings, NRG Energy and Vistra Energy Corp issued debt with BB ratings, and Talen Energy issued debt with B- and B+ ratings. See Appendix C of the Initial Draft Report.

B. A 17-Year Amortization Period is Unreasonable

The consultants recommend amortizing the costs of the thermal peaking plant technology over a period of 17 years, down from previous DCRs. Previous resets used an amortization period of 20 years. It is important to recognize that this is already a very conservative assumption given that the consultants assume the project would have $0 residual value at the end of the 20-year period. In reality, resources have substantial residual value and have generally continued to produce substantial net revenue for decades after this 20-year timeframe.

In this reset, the consultants recommend a shorter amortization period due to the requirement that New York's power system be "zero emissions" by 2040 under the CLCPA. This recommendation ostensibly reflects an assumption that the default CONE unit, which would initially be fired on natural gas, would be compelled to retire in 2040. This is an unsupported assumption and is not supported by the studies of the CLCPA mandates.

Hence, we find that adopting a 17-year amortization period is unreasonable and will result in excessively high demand curves. Instead, we recommend maintaining a 20-year amortization period. To the extent that uncertainty is heightened regarding the cost of the fuel that will be used by the peaking plant in 2040, as we discuss below, we recommend accounting for this by eliminating the energy net revenues in the last three years.

This is a conservative assumption because energy net revenues due to increases in shortage pricing would likely be substantial for the peaking plant. However, this approach is not as unreasonably conservative as the 17-year amortization assumption. The effects of adopting this recommendation together with a 6.25 percent COD is shown in the following table.

Table 3: Estimated Effects of Shortening the Amortization Period

Zone	Estimated Net CONE Impact	
	Price Impact ($/kW-year)	Percentage Impact (%)
C	$6.37	8.8%
G (Rockland)	$8.77	9.0%
J	$7.70	5.0%
K	$9.23	8.9%

CLCPA's Potential Effect on the Economic Life of the Peaking Plant

Although state agencies have not issued official regulations or guidance regarding fuels that will be compliant with the CLCPA in 2040, it is already clear that fossil-fueled generators will be able to comply by switching to alternative fuels. Although such fuels are not commercially widespread, such technologies exist and developers in New York are including the flexibility to adopt them in their plans.[3] These technologies are not currently widespread because fossil fuels are less expensive in under current laws and regulations, but these technologies will likely become widespread if New York State and other jurisdictions prohibit the use of less expensive fossil fuels. The consultants' reluctance to make specific assumptions about fuel switching is understandable given the lack of certainty about these technologies. Such uncertainty is inherent regarding conditions and technologies 20 years in the future. The objective should be to use the most reasonable expectation possible and not to be limited by current conditions. Therefore, we find that assuming that all fossil-fuel generators will retire by 2040 is excessively conservative and unreasonable. In fact, recent studies support that this is not a reasonable expectation, including one by the consultant itself.

Recent studies by both Analysis Group and Brattle Group evaluate 17 to 33 GW of fossil fuel-fired generation being converted to CLCPA-compliant zero-emission fuels by 2040. These studies find that large amounts of flexible generation are needed to maintain reliability, generally operating in reserve with very low capacity factors. Brattle Group finds that prohibitively large amounts of renewable and battery resources would be needed to replace the flexibility these resources provide.[4,5]

For example, in a scenario that was seemingly devised to demonstrate the absurdity of assuming no fuel-switching, the Brattle study found extreme outcomes including incremental 'overbuild' of renewable and storage capacity by over 100 GW and massive (on the order of 50 percent) curtailment of renewable generation. While these studies do not purport to predict how the CLCPA will be achieved, the studies show that there is not a reasonable basis for assuming that all existing dispatchable resources will retire.

---

3 For example, the developer of the proposed Danskammer gas-fired repowering project in Load Zone G states that "A modernized Danskammer can transition to zero-emission hydrogen power when the technology is available to transport and store hydrogen." See https://www.danskammerenergy.com/energy-project/

4 Brattle Group was commissioned by NYISO to conduct long-term modeling of New York's power system complying with CLCPA mandates. Results of Brattle's analysis show over 20 GW of CC, CT and ST capacity maintained by 2040 in a 'reference load' case and over 33 GW in a 'high electrification' case considering demand-side impacts of the CLCPA (an increase from currently existing capacity). In both cases, thermal plants are assumed to operate on a generic zero-emission fuel after 2040. A scenario assuming that a dispatchable zero-emission fuel of this type cannot be used had dramatic results including additional 'overbuild' of 80 GW of renewables and 27 GW of energy storage relative to the base case, curtailment of 50% of renewable generation, and serious challenges satisfying UCAP reserve margins. See https://www.nyiso.com/documents/20142/13245925/Brattle%20New%20York%20Electric%20Grid%20Evolution%20Study%20-%20June%202020.pdf/69397029-ffed-6fa9-cff8-c49240eb6f9d

5 Analysis Group was commissioned by NYISO to analyze challenges to NYISO system reliability in 2040 as part of the NYISO's Climate Change Phase II study. In developing assumptions for cases with a resource mix consistent with CLCPA mandates, Analysis Group found a need for 17 to 29 GW of "generic dispatchable" technology to meet demand during periods of low intermittent resource output even after other flexibility-enhancing additions including 8 to 13 GW of energy storage, relaxed transmission constraints and an increase in price-responsive demand. See https://www.nyiso.com/documents/20142/12899859/07_TPAS-ESPWG_Analysis%20Group%20Climate%20Change%20Phase%20II%202020.06.04.pdf/dbe8c45a-ede7-4801-1f43-adeb35c002af

A full 20-year amortization period is compatible with the potential need to incur compliance costs in the future. The use of alternative fuels or other retrofits to comply with CLCPA requirements may require modest additional capital costs in the future. But a broadly applied prohibition on fossil fuel use would lead to higher future capacity, energy, and ancillary services prices to maintain an adequate supply of dispatchable generation and, therefore, need not be included in the Net CONE today. The peaking plant is newer and uses more advanced technology than other existing thermal generators in NYISO. Hence, it is not likely to be among the most expensive dispatchable generators to maintain in operation as environmental regulations grow stricter. As a result, a 20-year amortization period without adjustment for additional future capital costs is reasonable for such a unit.

CLCPA's Potential Effects on the Revenues of the Peaking Plant

Much of the discussion of this issue and potential impact of other future changes in environmental regulation have assumed that existing suppliers face only downside risks from regulatory changes. However, this ignores that stricter environmental standards and the large-scale entry of renewable resources could lead to two sources of much higher revenues:

- Fluctuations in intermittent output and forecasts errors of this output will rise as the reliance on renewable resources rise. This will likely increase the frequency of operating reserve shortages. Given the performance characteristics of the peaking plant, it will realize sizable increases in shortage revenues during these events.

- If all thermal units were to retire by 2040, investment in gas-fired units would not be viable and future demand curves would be set by more expensive technologies. In such a scenario, a peaking plant entering service in the next four years would benefit from higher capacity prices than are implied in the present DCR in the timeframe prior to 2040.

Attempting to quantify these and other market impacts of the CLCPA over the next two decades would necessarily be speculative and unreasonable for the DCR process. Hence, we recommend NYISO avoid selectively incorporating uncertain future impacts, and adopt a 20-year amortization period that remains a reasonable assumption that accounts for the market uncertainties on both the downside and upside. To account for the likelihood that alternative fuels will be more costly, the consultants could consider eliminating the energy revenues for the last three years of the project's life and retaining only reserve revenues during those years.

C. Cost of Fuel to Provide Operating Reserves

In their preliminary model of energy and ancillary services ("E&AS") revenues, the consultants assumed that the peaking plant incurs a fuel procurement cost when providing operating reserves. The unit is assumed to purchase gas to cover each hour of its reserve schedule in case it is called upon to provide energy in real time. If the unit does not provide energy in real time, the fuel is assumed to be sold back at an intraday discount of 10 percent in Load Zones C through G, 20 percent in Load Zone J, and 30 percent in Load Zone K. These assumed costs reduce net E&AS revenues and therefore increase the Net CONE. We recommended that the cost of reserves be reduced to a realistic level of $2.0/MWh or lower. This is especially reasonable for dual fuel units, which can be available to provide reserves without scheduling natural gas. As of the Interim Final Draft Report, the consultants have updated their Net E&AS model to use a $2.00/MWh cost of reserves for dual fuel units. The remainder of this section provides support for the consultants' assumption regarding the cost of reserves.

There are multiple ways that a generator can ensure it is able to convert its reserves to energy when needed without purchasing gas equivalent to its entire reserve schedule. Generators can typically acquire gas in the intraday market under most conditions. A generator with dual fuel capability can rely on its on-site oil for rare events when intraday gas is unavailable and offer energy at a correspondingly high bid price. It is unreasonable to assume that such a unit will regularly procure gas far in excess of what it expects to burn whenever it provides reserves. The preliminary model overstated the cost of reserves, especially in Load Zones J and K, by linking it to a fuel procurement strategy that is not representative of the actual behavior of reserve providers in New York.

For the previous methodology that was used in the Initial Draft Report, Table 4 shows the average annual number of hours in which the peaking plant (a) sells day-ahead reserves and (b) has no day-ahead or real-time market commitment. It also shows the average annual reserve net revenues.[6]

Table 4: Commitment Summary in Initial Draft Report

Zone	Intraday Gas Discount	Average Annual Value: Hours DA Reserve Commitment	Average Annual Value: Hours No DA or RT Commitment	Average Annual Value: Reserve Net Revenues ($/kW-year)
C	10%	7,154	393	$12.9
G (Rockland)	10%	5,948	559	$11.5
J	20%	1,085	5,489	$1.7
K	30%	111	5,418	$0.8

Table 4 shows that the peaking plants sell day-ahead reserves in only 12 percent of hours in Load Zone J and 1 percent of hours in Load Zone K and earn minimal profit when doing so if the previous methodology is used. These units have no day-ahead market or real-time market energy or reserve commitment in over 60 percent of hours – hence, the lack of reserve hours cannot be explained by more profitable energy market opportunities. These results suggest that the units in Load Zones J and K are usually priced out of the reserve market because of the high assumed cost to provide reserves. This is not reasonable given that the peaking plant technology would be among the most flexible resources in NYISO and would likely be an active reserve

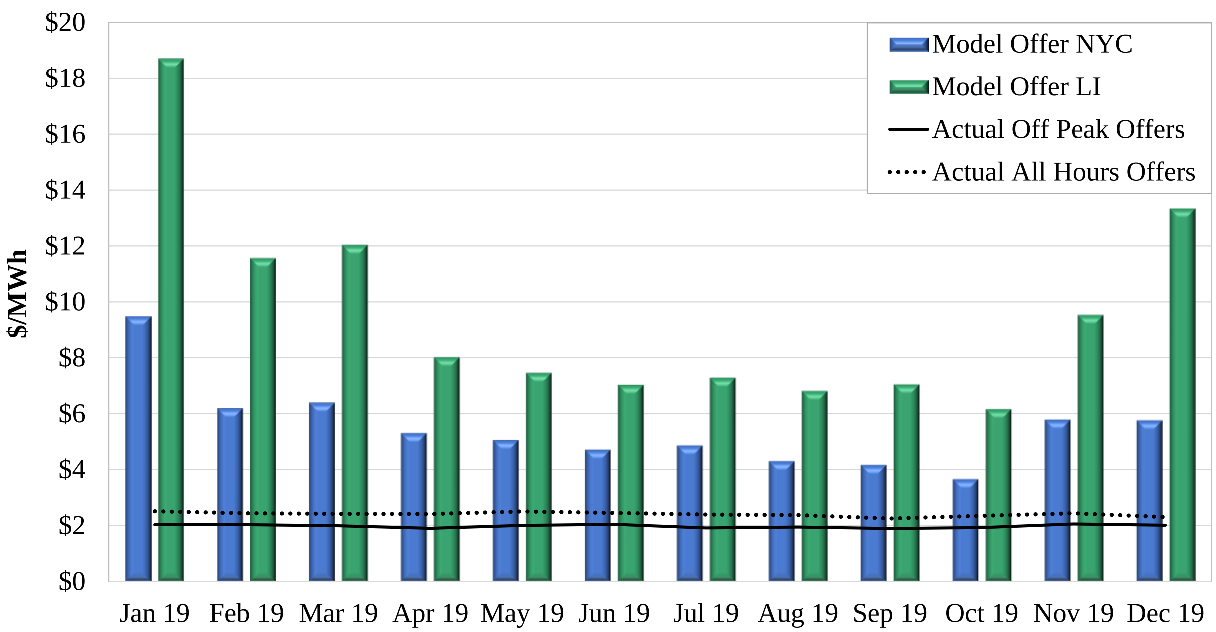
6 Data is from Appendix D of the Initial Draft Report. Day-ahead reserve hours include any hours in which the unit has a day-ahead reserve commitment, including if it buys out in real-time dispatch. "Reserve Net Revenues" includes net revenues in hours when the unit either provides reserves in the real-time market or provides reserves in the day-ahead market and subsequently buys out of its position in the real-time market.

market participant. As of the inclusion of a $2.00/MWh cost of reserves in the Interim Final Draft Report, this result has been made more realistic with the peaking plant in zones J and K providing reserves in over 6,000 hours per year.

Actual reserve offer data from suppliers in New York is instructive given that these offers should reflect the costs the consultants are attempting to quantify. This data supports a cost of reserves of approximately $2.0/MWh as shown in the following figure. Figure 2 compares actual historical day-ahead reserve offers for gas-only and dual fuel units in Load Zones J and K in 2019 to the implied cost of reserves in the draft net E&AS model.[7]

Figure 2 shows that the capacity-weighted average reserve offer was $2.0/MWh during off-peak hours, when offers are likely to be more competitive, and $2.4/MWh in all hours. Typical reserve offers had little variation across months. By contrast, the draft model methodology implied an average cost of $6/MWh in Load Zone J and $9/MWh in Load Zone K in 2019, with monthly averages as high as $9 in Load Zone J and $18/MWh in Load Zone K.

Figure 2: Cost of Reserves in Draft DCR Model vs. Historical Average DA Reserve Offers



Based on this data, we recommended that the consultants replace the fuel-based cost of selling reserves in the day-ahead market with a constant cost of $2.0/MWh. This will align the modeled cost with typical offer prices for similar existing units in New York. In the Interim Final Draft Report the consultants accounted for this recommendation and modified the cost of reserves for dual fuel units in their Net E&AS Model to $2.00/MWh.

7 We used hourly day-ahead offer data from units at five plants in zones J and K that offered 10-minute non-spin 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.

D. Comments on Preliminary Recommendations for Load Zone C

Appropriateness of Use of Central Zone for NYCA Demand Curve

The consultants estimated a lower Net CONE value for the peaking plant located in Load Zone C than for the one in Load Zone F. Although Load Zone F was used as the location of the unit for the NYCA demand curve in the 2016 DCR, the consultants have recommended using the Load Zone C unit in this reset based on the preliminary results reflected in the Initial Draft Report.

We support the recommendation to use the Load Zone C unit because of its lower Net CONE and because it seems very unlikely that transmission constraints will lead capacity in Load Zone C to be less deliverable than capacity in Load Zone F for the foreseeable future. NYISO's most recent New Capacity Zone study issued in January 2020 found 858 MW of deliverability headroom between the Load Zone A-E and Load Zone F regions – an increase from 316 MW as of the last reset and more than enough to accommodate the peaking plant.[8]

The AC Transmission Projects approved by NYISO in 2019 and scheduled to enter service in December 2023 will further expand transfer capability on the Central East interface during the reset period. Hence, we consider that the unit located in the lower cost location – Load Zone C as of the Initial Draft Report – is very likely to be deliverable throughout the NYCA region. Therefore, this location should be used as the basis for the NYCA demand curve.[9]

Natural Gas Price for Load Zone C

The consultants propose to use a gas-only generator which purchases fuel at the TGP Zone 4 (200L) price plus a transport cost of 27 cents per MMbtu in the day-ahead market. In the real-time market, the consultants assume the unit would pay a 10 percent premium on gas to generate above the day-ahead schedule and receive a 10 percent discount on gas sold if it generates less than the day-ahead schedule.

To provide further analysis of the suitability of the consultants' recommendation, we considered historical benchmarking of gas-fired plants in Zone C, gas pipeline operational capacity and critical notice data, and the amount by which the recommendation might overstate E&AS revenues compared to another plausible alternative.

It is important to strike a reasonable balance that avoids significant over or under-estimation of net revenues for the demand curve unit. There may be circumstances when a specific set of assumptions over or under-estimate the fuel costs of a generator on specific days. However, it is

8 See NYISO 2019/2020 New Capacity Zone Study, https://www.nyiso.com/documents/20142/6004104/2019-2020-NCZ-Study-Report.pdf/780f36e1-cee5-a174-5e7d-f5d2dbcaffd7

9 While present conditions support this conclusion, we continue to support efforts to develop more granular capacity zones which would improve price formation if deliverability constraints within present capacity regions become binding in the future.

also important to limit the complexity of the consultants' net E&AS revenue estimation model and the annual demand curve update process.

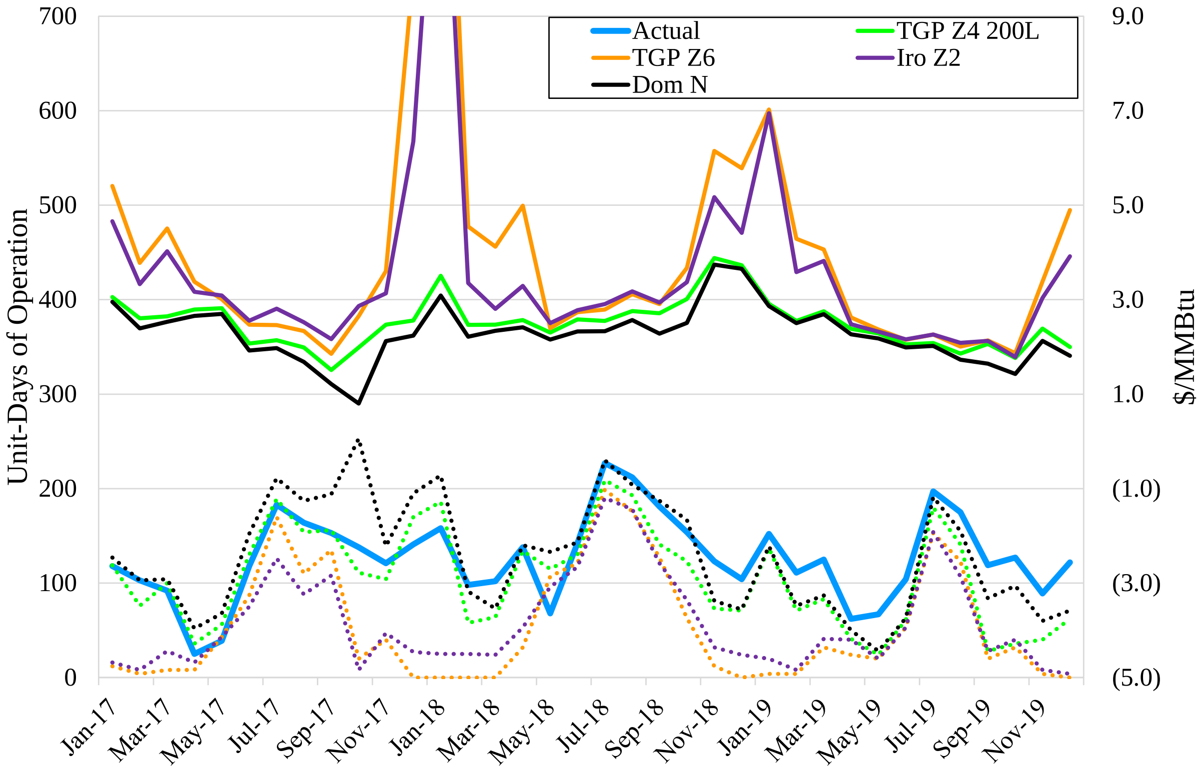
Analysis of Historical Plant Operations

Figure 3 compares the actual number of days of historical operation for nine gas-fired units in Zone C to a backcast simulation for each unit under alternative fuel price assumptions. The simulation was performed using hourly day-ahead and real-time historical LBMPs at each plant node, daily gas indices for each hub from SNL, and plant parameters derived from unit-specific reference level data and plant-level EPA data. 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 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.

Of the four alternative gas hubs used, TGP Z4 200L and Dominion North were better predictors of actual Zone C plant operation than TGP Z6 and Iroquois Z2. Notably, this result holds in winter months, when prices at TGP Z6 and Iroquois Z2 often spike to high levels. During these periods, plants in Zone C operated much more often than would be expected if facing fuel costs at the TGP Z6 or Iroquois Z2 levels. Existing plants may have unique fuel supply arrangements that do not necessarily align with what the Demand Curve unit could expect to obtain.[10] However, this analysis indicates that gas priced at a discount to TGP Z6 and Iroquois Z2 hubs is available in central New York, including during winter months.

10 Additionally, most existing units in Zone C are behind local distribution company (LDC) systems and likely face additional costs and flow constraints that the demand curve unit would not face.

Figure 3: Historical vs. Backcast Operation for Zone C Gas-Fired Plants

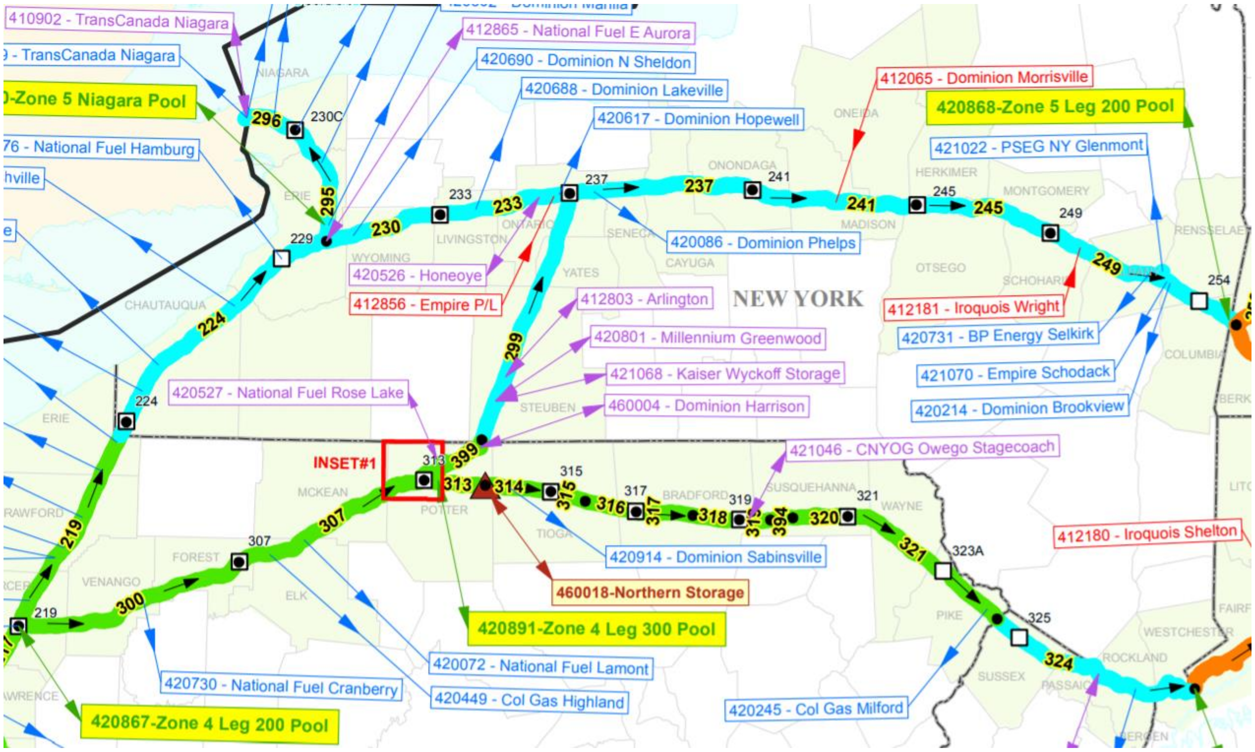


Suitability of Gas Hub Alternatives

The choice of gas hub for the Zone C unit is complicated by the lack of a liquid trading hub located in Zone C. Figure 4 shows a map of the TGP 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). Hence, TGP Z4 200L is geographically accessible during times when capacity is available for interruptible transport on TGP to Zone C. The TGP Zone 5 price refers to deliveries downstream of station 245, aligning more closely with NYISO Zone F than Zone C.[11] This index (along with others available in Zone F such as Iroquois Z2 and TGP Z6) is therefore geographically accessible but not an appropriate pricing choice unless no other upstream alternatives are available. Finally, the Niagara hub located on the border with Ontario in western New York is geographically accessible via the TGP pipeline between zones A and C.

11 S&P Global Platts defines Tennessee, Zone 5 (200 leg) as "Deliveries from Tennessee Gas Pipeline Zone 5, downstream of compressor station 245 extending to and including station 254."

Figure 4: Map of TGP Pipeline in New York

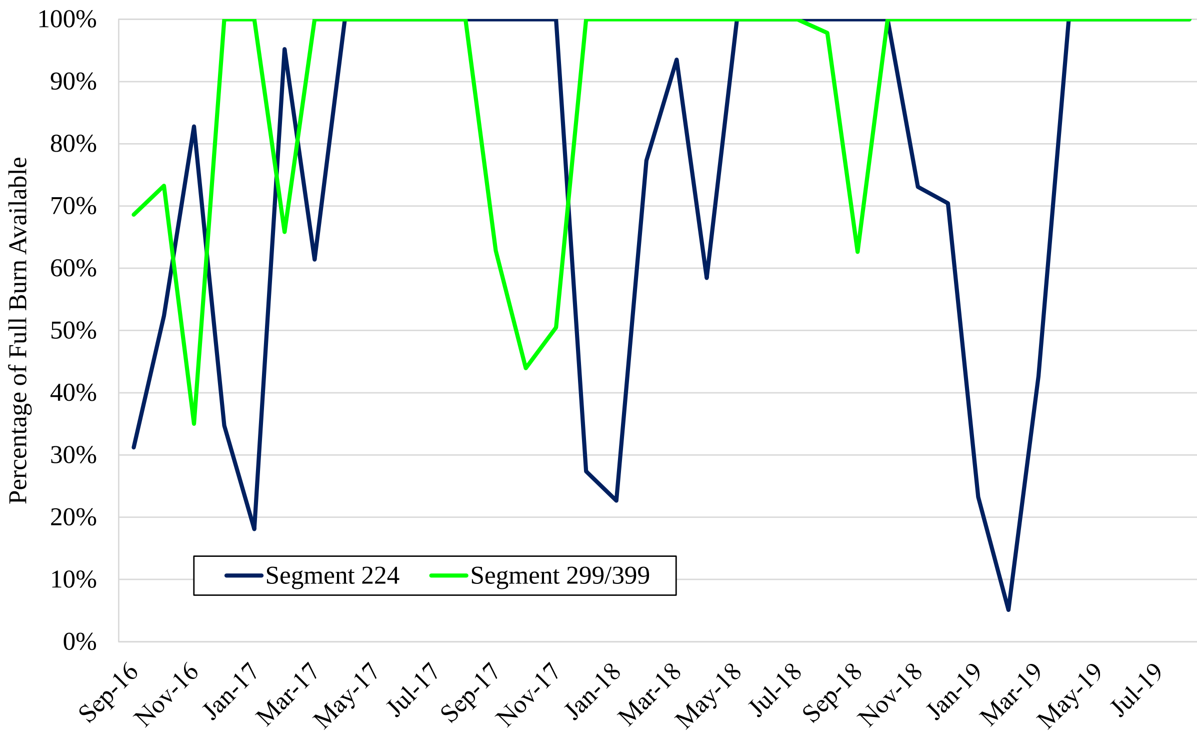


Operating Capacity Data

Figure 5 shows the historical average daily operational available capacity on TGP segments entering New York from Zone 4, as a percentage of the daily gas that would be required for the peaking plant to operate for 24 hours (approximately 75,000 Dth).[12] Capacity on Segment 224 connecting TGP Z4 200L to western New York was available in most months, but was frequently severely constrained in winter. Capacity on Segments 399 and 299 connecting TGP Z4 300L to central New York had greater availability. However, a review of daily critical notices issued by the TGP pipeline indicates that interruptible transport on both the 224 and 299 segments is frequently subject to restriction, particularly in winter. This data suggests that the purchase of gas at the TGP Z4 200L hub and transport to New York using interruptible service is often not possible during winter. In such months, the use of TGP Z4 200L as the gas hub may overstate net energy revenues of the peaking unit.

12 Available capacity data is obtained from SNL and reflects capacity in the Timely nomination window.

Figure 5: Operational Available Capacity on TGP Segments Entering New York



An alternative to offset the potential over-estimate of E&AS revenues is to use the Niagara hub in winter months. New York consistently exports gas to Canada via the Niagara interconnection between TGP and TransCanada. Hence, the price at Niagara can be seen as a proxy for the cost of acquiring gas at points in Zone A upstream of the Niagara spurline (segments 295 and 296). Data on operational available capacity indicates that segments in between zones A and C (segments 230 and 233) are rarely constrained, while segments further downstream in between zones C and F are frequently constrained in winter. Hence, the use of the Niagara price during winter months is reasonable for the region in between the bottleneck separating Zone 4 from New York and the bottleneck separating central from eastern New York.

The Niagara gas index is limited by its relative lack of liquidity. Niagara lacks significant trade volume on many days during the historical period used to estimate E&AS revenues. A potential solution is to consider the Dawn Ontario gas price, either for all days when Niagara would be used or on days when Niagara lacks trade volume. Dawn is connected to Niagara on the TransCanada system and historically exhibits very closely correlated prices with Niagara.

Potential Impact

Table 7 shows annual average net revenues of the peaking unit estimated using the Interim Final Net E&AS Model with alternative winter gas pricing assumptions. If Niagara is used in December through March instead of TGP Z4 200L, net E&AS revenues decline by $3.8/kW-year. This suggests that the impact of using TGP Z4 200L in months when it is restricted is relatively small compared to a reasonable alternative in upstate New York. If TGP Z6 is used in

December through March, net E&AS revenues decline by $14.4/kW-year, to a level even lower than the $29.0 estimated by the consultants for the proxy unit in Zone F. Using a price that does not acknowledge any winter fuel price advantage for generators in western and central New York would result in net revenues that are likely significantly understated.

Table 7: Zone C Net E&AS Revenues[13]

Fuel Price Assumption	Average Annual E&AS Revenues
TGP Z4 200L + $0.27	$39.4/kW-year
TGP Z4 200L + $0.27 (Apr – Nov) Niagara + $0.27 (Dec – Mar)	$35.6/kW-year
TGP Z4 200L + $0.27 (Apr – Nov) TGP Z6 +$ 0.27 (Dec – Mar)	$25.0/kW-year

Although there are circumstances when the use of the TGP Z4 200L or Niagara indices could lead to an over-estimate of net revenue on individual days, we note that the resulting impact is offset by other conservative assumptions related to fuel costs. In particular, the assumed cost of securing gas to cover 100 percent of day-ahead reserve commitments results in a cost of providing reserves that is likely conservatively high, compared to the $2.0/MWh cost of reserves adopted by the consultants for generators in zones G-K. This results in net E&AS revenues in Zone C that are approximately $4.6/kW-year lower than if a $2.0/MWh cost of reserves were used, and this impact would larger and more problematic if a higher gas cost were adopted. The 10 percent premium or discount for intraday fuel purchases or sales is also likely to be excessive on most days. Finally, the annual run hour restriction of 1,060 hours for the peaking unit in Zone C to comply with NOx emission standards limits the extent to which net revenues increase if gas prices are under-estimated.

Conclusions Regarding Gas Prices

The consultants' recommended gas cost of TGP Z4 200L + $0.27 is appropriate for Zone C during much of the year. It is important that the selection of gas hub recognize that there is a lower cost of fuel in western and central New York than in eastern New York, including in winter months. Gas hubs associated with eastern New York such as TGP Z6 and Iroquois Z2 are therefore not appropriate. Direct transport from the TGP Z4 200L region to 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, we recommend that the consultants use the Niagara price hub plus $0.27 in winter months and TGP Z4 200L plus $0.27 in all other months.

Compliance with Environmental Regulations

The consultants have recommended the use of a peaking plant without selective catalytic reduction ("SCR") emissions controls and with a 17-year amortization period in Load Zone C. Counties in the Central Zone are not currently classified as being in Severe Nonattainment area

13 Net E&AS revenues were calculated using the Interim Final Thermal Net E&AS Model published by the consultants on August 10, 2020 and do not include the VSS adder.

with the National Ambient Air Quality Standard ("NAAQS"). The consultants' opinion is that the unit may accept limits on run hours instead of installing SCR emissions controls. This is appropriate and is consistent with assumptions for Load Zones C and F in prior DCRs.

E. Preliminary Recommendations for Load Zone G – Dutchess County

Compliance with Environmental Regulations

The consultants recommend using a unit with SCR emissions controls in Dutchess County locations of Load Zone G. This region falls outside of the Severe Nonattainment area for the eight-hour ozone NAAQS. The consultants initially considered that a unit in this location could comply with air quality regulations by limiting its run hours to meet applicable emissions limits, and that this would be the lower-cost option compared to installation of SCR emissions controls. They subsequently amended their recommendation for Dutchess County to include SCR emissions controls.

In general, the consultants have used a reasonable and principled approach to decide whether to include SCR emissions controls on units outside of Severe Nonattainment areas. However, there is legitimate concern about the ability to cite a unit without SCR emissions controls in Dutchess County. Recent Article 10 siting processes suggest that a new plant in this region can expect intense local opposition and may regard state of the art emissions controls as a necessity. Hence, it may be appropriate to consider factors beyond the emissions regulations in determining whether SCR emissions controls should be included for the peaking plant in Dutchess County.

Notwithstanding, based on the results reflected in the Interim Final Draft Report, the Rockland County unit is expected to be the basis for the demand curve covering the G-J Locality, so the SCR emissions controls assumption for the Dutchess County unit should not ultimately affect the capacity demand curves over the next four years.

F. Preliminary Recommendations for Load Zone G – Rockland County

Use of TETCO-M3 as Natural Gas Hub

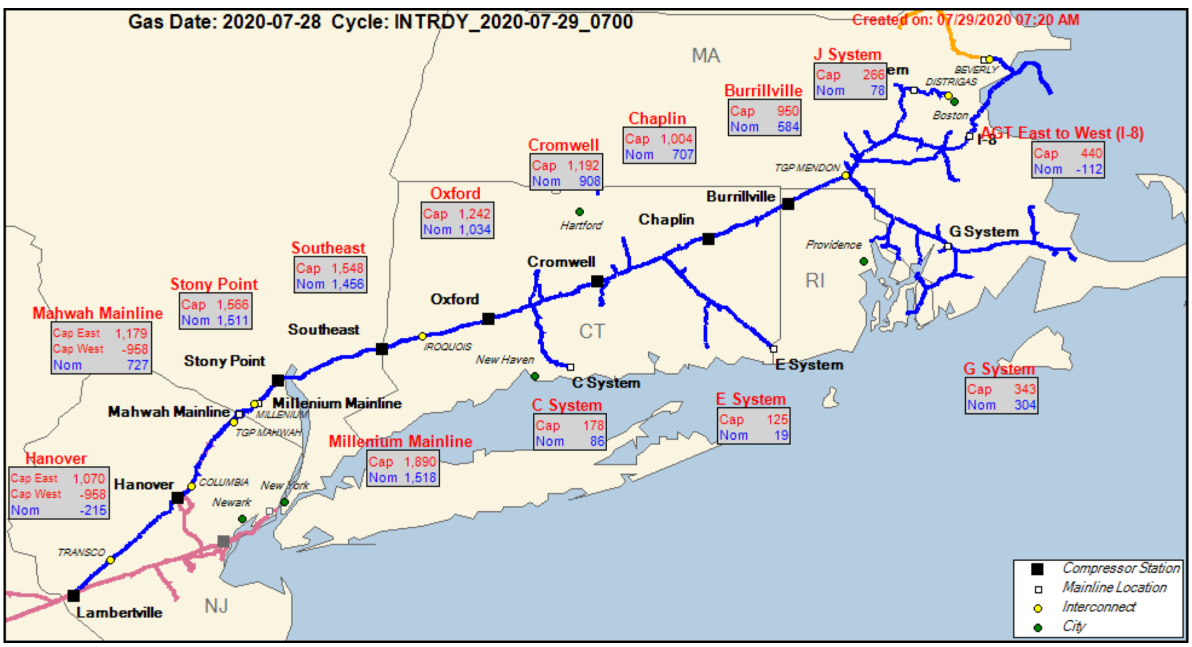
We support the consultants' recommendation to use the TETCO M3 gas index price plus a transportation cost of $0.27/MMBtu for a plant in the Rockland County location in Load Zone G. The TETCO M3 market zone does not geographically include points in Rockland County, but it does include points of interconnection with the Algonquin pipeline at Lambertville, NJ and Hanover, NJ.[14] Although firm forward-haul transport capacity for this segment of the Algonquin pipeline is not currently available, gas purchased in the TETCO M3 market zone can be transported on an interruptible basis by paying Algonquin's AIT-1 tariff rate (currently

14 S&P Global Platts defines the Texas Eastern, M-3 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".

$0.2421/MMBtu).[15] Such interruptible transport is generally available to points in Rockland County. Pipeline bottlenecks typically occur downstream of points in Rockland County and upstream of Algonquin Citygates delivery points and the pipeline's interconnection with Iroquois.[16] In rare situations when interruptible transport to Rockland County is not available, a plant equipped with dual fuel capability (as assumed by the consultants) can rely on oil to meet its capacity obligation.

Pipeline data supports the finding that gas transported from the TETCO M3 zone via Algonquin is available in Rockland County. Algonquin announces any restrictions on customers' gas transport nominations via daily critical notices when conditions warrant such restrictions. In 2019, Algonquin announced restrictions on interruptible 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 located on the west shore of the Hudson River at the eastern border of Rockland County (see Figure 6 below). Hence, while transport on Algonquin is frequently restricted, the main bottlenecks are located downstream. Transport to points in Rockland County such as the interconnect with Millennium Pipeline at Ramapo is generally available.

Figure 6: Map of Algonquin Pipeline



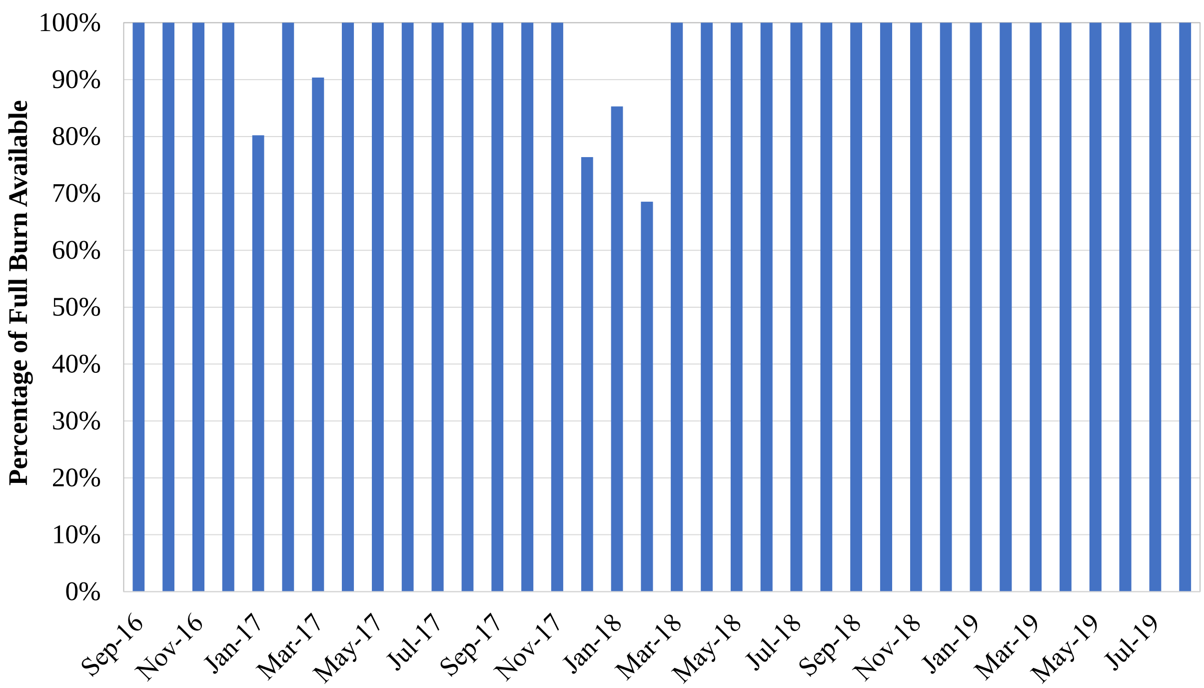
15 The owner of Algonquin has recently filed rates with FERC which would increase the maximum interruptible transport (AIT-1) rate to $0.2867/DTh. These rates have not yet been approved at the time of writing.

16 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". The Iroquois pipeline interconnections with Algonquin in Connecticut.

Figure 7 shows the average daily operational available capacity on the Algonquin pipeline segment passing through the Millennium Mainline station in Ramapo, NY as a percentage of the daily gas that would be required for the peaking plant to operate for 24 hours (approximately 75,000 Dth).[17] Average available capacity exceeded the maximum daily burn in most months, and covered a high percentage of maximum 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, as noted above, the recommended peaking plant design for Rockland County is dual fuel and, therefore, also has the option to run on oil in the minority of days when gas may not be available.

Hence, we consider the consultants' use of TETCO M3 plus $0.27/MMBtu (along with the assumed intraday premium or discount of 10 percent) to be appropriate for the Rockland County unit, while use of the Algonquin Citygate or Iroquois Zone 2 hubs would be inappropriate given the county's proximity to the TETCO M3 market zone.

Figure 7: Operational Available Capacity on Algonquin Millennium Mainline Segment



G. Comments on Preliminary Recommendations for Load Zone J

Switchyard and Interconnection Costs

The consultants' recommendation to use gas-insulated switchgear (GIS) instead of air-insulated switchgear (AIS) in Load Zone J is conservative. Con Edison Transmission Planning Criteria do not mandate use of GIS for new facilities, but the consultants assume that GIS is used in dense urban areas due to space constraints and aesthetic considerations. The consultants indicated in

17 Available capacity data is obtained from SNL and reflects capacity in the Timely nomination window.

the NYISO stakeholder process that the use of GIS instead of AIS results in a reduction of assumed land footprint for the Frame unit, from 15 acres to 12 acres, with a corresponding reduction of land lease costs (approximately ~$2/kW-year).[18] This 3-acre reduction of land footprint comes at significant expense, equivalent to an approximately $33 million difference (or ~$12/kW-year) in capital cost between GIS and AIS.

In general, it is appropriate to evaluate design choices on an economic basis when multiple choices are permissible. Such logic would favor use of the lower-cost AIS switchgear in Load Zone J with commensurately higher lease costs due to use of a 15 acre site instead of a 12 acre site. However, it is reasonable to consider that limited availability of land in practice could restrict developers' switchgear choices at some locations in Load Zone J. Evidence from other recent projects in New York suggests that developers have selected GIS in consideration of land footprint impact, even outside of New York City.[19]

Hence, we do not recommend that the consultants modify the assumption that GIS would be selected in Load Zone J, but it should be emphasized that this assumption is likely to err on the conservative (higher cost) side of available design choices. Conservativeness in this area should be taken into consideration when assessing the overall reasonableness of the New York City demand curve.

We note that some stakeholders have raised concerns that elements of the consultants' switchyard and interconnection costs do not align with their own experience. Projects each face unique risks and will have cost items that vary above and below what is assumed by the DCR. Individual assumptions that are conservative or optimistic within the range of reasonable costs do not necessarily imply that the gross CONE is biased upward or downward overall.

H. Conclusions

The consultants performed a comprehensive analysis of the costs of new entry in each capacity region in New York. This required an in-depth analysis and estimates of a comprehensive set of parameters. In these comments, we identify several areas where additional refinements or modifications are warranted. We also discuss certain assumptions or approaches proposed by the consultants that we find to be reasonable. In summary, we recommend:

- Assuming a cost of debt between 6.0 and 6.5 percent, based on typical borrowing costs over a reasonable historical period.
- Adopting a 20-year amortization period instead of 17 years for thermal units. If the 20-year assumption is adopted, it would be reasonable to attribute zero energy revenues to the peaking plant during the last three years of the 20-year period.
- Basing the NYCA demand curve on the lower of the Load Zone C and Load Zone F Net CONE. Based on the Initial Draft Report, this would support the use of Load Zone C.

[18] See presentation by Burns & McDonnell to the Installed Capacity Working Group on May 19, 2020.

[19] For example, the recent Cricket Valley Energy and CPV Valley projects both made use of GIS switchgear.

- Using the TETCO M3 gas hub plus $0.27/MMBtu transport cost and assuming 10 percent intraday premium or discount for the Load Zone G (Rockland County) unit.
- Using TGP Z4 (200L) gas hub plus $0.27/MMBtu in the months of April through November and the Niagara gas hub plus $0.27/MMBtu in the months of December through March for the Load Zone C unit.

We believe establishing reasonable and realistic assumptions to calculate the net CONE for the capacity demand curves is essential and we encourage NYISO to adopt these recommendations.