Memorandum

TO: Analysis Group, Burns & McDonnell

FROM: David Patton, Pallas LeeVanSchaick

DATE: July 2, 2020

RE: MMU Comments on Independent Consultant Initial Draft ICAP Demand Curve Reset Report and Recommendations

In accordance with MST 5.14.1.2, the NYISO periodically conducts the 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 4, 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"). A final version of the report 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 consultant's Demand Curve Reset report in accordance with Market Services Tariff section 5.14.1.2.2. Prior to the issue of the draft report, we 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. In this memo, we recommend that following changes:

- Revise downward the cost of debt based on a broader viewer of the available data that does not over-emphasize the recent COVID-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 7.7 percent.
- 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 CLCPA.

- Eliminate the fuel procurement cost associated with the sale of operating reserves for dual fuel units. This would more accurately reflect the flexibility of a resource in New York with oil backup because such units would not likely incur these costs.

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

- Setting the NYCA demand curve based on the Zone C proxy unit, since this unit is expected to be deliverable in Rest of State (i.e., Zones A to F);
- Using the TGP Z4 (200L) index plus $0.27/MMBtu for the cost of gas in Zone C.
- Using the TETCO M3 index plus $0.27/MMBtu for the cost of gas in 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. However, 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. We have observed that bond yields fell near pre-COVID levels during June and that the effects of the pandemic on bond yields have been largely temporary. 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 the most recent information available. However, we are concerned that heavily weighting contemporaneous data would overemphasize recent market turbulence. 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.

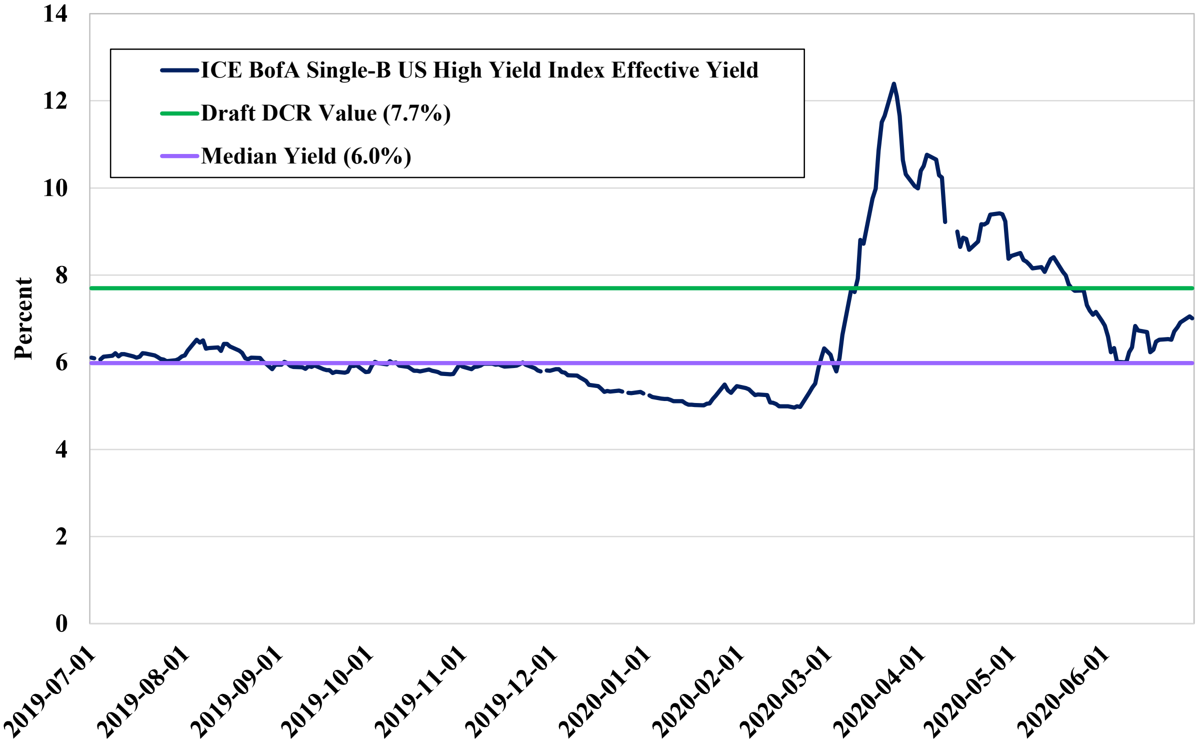
Market conditions have already changed considerably from the time when the consultants developed their recommendation. When presenting their rationale for a higher cost of debt in May 2020, the consultants highlighted costs of B-rated debt at 12.4 percent on March 23 and 9.3 percent in the week of April 21.[1] Since May, the B-rated corporate debt benchmark has fallen considerably.[2] Chart 1 shows data on the Single-B US High Yield Index Effective Yield from

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. Of the companies examined, Calpine Corp issued debt with B and BB ratings, NRG Energy and Vistra Energy Corp issued debt

the Federal Reserve Bank of St. Louis for the year from July 2019 through June 30, 2020. Yields began to rise sharply in late February and remained elevated in April and May. Yields then fell close to pre-COVID levels before moving up again on news of a surge in new cases of the virus, with a median of 6.5 percent for the month of June.

Chart 1: B-Rated Bond Yield, July 2019 to June 2020



The purpose of this analysis is not to suggest that only the most recent yields during June 2020 should be used. Rather, it is to highlight that recent trends should provide grounds for extreme caution in considering how debt yields during the first half of 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 1 below shows median B-rated bond yields over a period of one, two, three, four or five years through June 30, 2020.

with BB ratings, and Talen Energy issued debt with B- and B+ ratings. See Appendix C of the Preliminary DCR Report.

Table 1: Median B-Rated Bond Yield Historical Median Daily Values

Period	Median Yield (%)
July 2019 - June 2020	5.98
July 2018 - June 2020	6.48
July 2017 - June 2020	6.34
July 2016 - June 2020	6.25
July 2015 - June 2020	6.43
Consultants' Draft Report	7.70

Median yields over these periods are consistent with an estimated cost of debt between 6.0 and 6.5 percent. We recommend that the consultants propose a cost of debt in this range based on historical borrowing costs over a period that includes data since the onset of COVID-19 but does not assign it disproportionate weight.

B. A 17-Year Amortization Period is Unreasonable

The consultants recommend amortizing the costs of the peaker technology over a period of 17 years, down from previous Demand Curve Resets, which have used an amortization period of 20 years. The consultants recommend a shorter amortization period due to the requirement that New York's power system be "zero emissions" by 2040 under the Climate Leadership and Community Protection Act (CLCPA). However, a 17-year amortization period is unreasonable and will result in excessively high demand curves. Instead, we recommend that a 20-year amortization period be used. The consultants should consider eliminating the energy revenues in the last three years to account for the effects of the CLCPA.

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 generators that are currently fossil-fueled will have ways to comply. Generators will likely be able to switch to alternative fuels, such as renewable natural gas or hydrogen. 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, but assuming that all fossil-fuel generators will retire by 2040 is excessively conservative.

3 For example, the developer of the proposed Danskammer gas-fired repowering project in 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/

The consultants issued a preliminary recommendation on this issue very early in the reset process (January). Since then, more information has become available that should be taken into consideration. Recent studies by both Analysis Group and Brattle Group evaluate 17 to 33 GW of fossil fuel-fired generation being converted to CLCPA-compliant fuel such as hydrogen or renewable natural gas 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. They find 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.

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 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 proxy unit 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.

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 renewable fuel after 2040. A scenario assuming that a dispatchable renewable 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 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

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 frequently benefit existing suppliers by making it more costly for competitors to enter the market and leading to two sources of much higher revenues:

- First, 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 proxy unit entering service in the next four years would benefit from higher capacity prices than are implied in the present DCR prior to 2040.

- Second, fluctuations in intermittent output and forecasts errors of this output in high renewable penetration scenarios will likely increase the frequency of operating reserve shortages and associated shortage revenues.

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 rely only on firm regulations that affect a unit's costs today and adopt a 20-year amortization period.

To account for the likelihood that alternative fuels will be more costly, the consultants should 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 model of E&AS revenues, the consultants assume that the proxy unit 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 Zones C through G, 20 percent in Zone J, and 30 percent in Zone K. These assumed costs reduce Net E&AS revenues and therefore increase the Net CONE.

We recommend that the cost of reserves be eliminated from the Net E&AS calculation for dual fuel units. 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, making the consultants' current approach quite conservative, even for a gas-only unit. 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. Hence, the consultants should eliminate this cost for dual fuel units. Instead, we recommend the consultants assume that a unit switching from a reserve schedule to energy in real-time will acquire gas at the relevant intraday premium.

D. Comments on Preliminary Recommendations for Zone C

Appropriateness of Use of Central Zone for NYCA Demand Curve

The consultants estimated a lower Net CONE value for the proxy unit located in Zone C than for the one in Zone F. Although Zone F was used as the location of the proxy unit for the NYCA demand curve in the 2016 Demand Curve Reset, the consultants have recommended using the Zone C unit in this reset.

We support the recommendation to use the Zone C unit because of its lower net CONE and because it seems very unlikely that transmission constraints will lead capacity in Zone C to be less deliverable than capacity in 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 Zone A-E and Zone F regions – an increase from 316 MW as of the 2016 Demand Curve Reset and more than enough to accommodate the demand curve proxy unit.[6]

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 proxy unit located in the lower cost location – Zone C as of the draft Demand Curve Reset 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.[7]

Natural Gas Price for 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.

Overall, we support these assumptions as striking a reasonable balance that is likely to avoid significant over or under-estimation of net revenues for the Zone C unit. The choice of gas hub is complicated by the lack of a liquid trading hub in Zone C. TGP Zone 4 (200L) is a reasonable representation of what a plant could pay under most conditions. Higher cost indices that apply to points to the east of Zone C, such as TGP Zone 5 or Zone 6, are not appropriate. In some circumstances when the pipeline system is highly constrained, TGP Zone 4 (200L) may understate what a plant in Zone C would pay for gas. However, this is offset by conservative

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6 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

7 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.

assumptions including: (a) the $0.27/MMBtu transport cost which may not be incurred by plants that are not connected to a local distribution company (LDC); (b) the 10 percent premium or discount for intraday fuel purchases or sales, which is excessive on most days; and (c) the assumed cost of securing gas to cover 100 percent of day-ahead reserve commitments (which is discussed above in Section C). While there are circumstances when these assumptions may over or under-estimate the fuel costs of a generator on specific days, any improvement would significantly increase the complexity of the consultants' net revenue estimation model and the annual demand curve update process.

Compliance with Environmental Regulations

The consultants have recommended the use of a proxy unit without SCR and with a 17-year amortization period in Zone C. Counties in the Central zone are not currently classified as being in Severe Nonattainment area with the National Ambient Air Quality Standard (NAAQS). The consultants' opinion is that the proxy unit may accept limits on run hours instead of installing SCR. This is appropriate and is consistent with assumptions for zones A-F in prior Demand Curve Resets.

E. Comments on Preliminary Recommendations for Zone G – Dutchess County

Compliance with Environmental Regulations

The consultants recommend using a unit without an SCR in Dutchess County. This region falls outside of the Severe Nonattainment area for the eight-hour ozone National Ambient Air Quality Standard (NAAQS). The consultants therefore consider 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.

The consultants have used a reasonable and principled approach to decide whether to include an SCR. However, there is legitimate concern about the ability to cite a unit without an SCR 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 an SCR should be included for the demand curve unit in Dutchess County.

Notwithstanding, the Rockland County unit is expected to be the basis for the demand curve covering Zone G, so the SCR assumption for the Dutchess County unit should not ultimately affect the capacity demand curves over the next four years.

F. Comments on Preliminary Recommendations for 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 Rockland County. 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.[8] 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 $0.2421/MMBtu).[9] 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.[10] 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.

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.

G. Comments on Preliminary Recommendations for Zone J

Switchyard and Interconnection Costs

The consultants' recommendation to use of gas-insulated switchgear (GIS) instead of air-insulated switchgear (AIS) in 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 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).[11] 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 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

8 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".

9 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.

10 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.

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

developers' switchgear choices at some locations in 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.[12] Hence, we do not recommend that the consultants modify the assumption that GIS would be selected in 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 Zone J 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. Conclusion

The consultants performed a comprehensive analysis of the costs of new entry in each locality 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 controversial assumptions or approaches proposed by the consultants that we find to be reasonable. In summary, we recommend:

- A cost of debt between 6.0 and 6.5 percent, based on typical borrowing costs over a historical period of at least one year.
- A 20-year amortization period instead of 17 years. If the 20-year assumption is adopted, it would be reasonable to attribute zero energy revenues to the proxy unit during the last three years of the 20-year period.
- The elimination of the cost of fuel for dual-fuel units providing operating reserves.
- The NYCA demand curve should be based on the lower of the Zone C and Zone F Net CONE. Based on the initial draft report, this would support the use of Zone C.
- The use of the TGP Zone 4 (200L) gas hub plus $0.27/MMBtu transport cost and an assumed 10 percent intraday premium or discount is appropriate for Zone C.
- The use of the TETCO M3 gas hub plus $0.27/MMBtu transport cost and an assumed 10 percent intraday premium or discount is appropriate for Zone G – Rockland County unit.

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