Securing 100+kV Transmission Facilities in the Market Model

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1. Purpose

The 2015 State of the Market (SOM) report includes a recommendation to model 100+kV transmission facilities as secured in the Day-Ahead (DA) and Real-Time (RT) markets using security constrained unit commitment and economic dispatch software and to develop associated mitigation measures. The purpose of this paper is to outline the feasibility and potential costs and benefits of securing 100+kV transmission facilities in the DA and RT market models. The study seeks to identify the impacts of securing 100+kV facilities and identifies New York Independent System Operator (NYISO) procedure changes necessary to effectuate the proposal.

2. Background

Today, the NYISO is registered as the North American Electric Reliability Corporation (NERC) Transmission Operator (TOP) for the New York Control Area (NYCA) 230 kV and higher transmission system. The Transmission Owners (TOs) are registered TOPs for the lower kV system. In this role, the TOs are ultimately responsible to NERC.[1] If there are insufficient resources for the energy markets to solve lower kV transmission constraints, then the TOs must develop a contingency plan. The NYISO helps the TOs to manage these transmission constraints through out-of-merit (OOM)[2] generation actions, Day-Ahead Reliability Unit (DARU)[3] actions, and Supplemental Resource Evaluations (SREs)[4] coordinated with the applicable local TO. The NYISO already addresses a limited set of lower voltage needs in its market software by de-rating surrogate interfaces that were specifically developed to identify and address the needs; this approach is generally used to secure transmission constraints indirectly when particular outage conditions

[1] The NYISO is not proposing to assume the TOs role as the registered TOP for transmission facilities below 230 kV.

[2] Out-of-Merit (OOM) is defined as: The designation of Resources committed and/or dispatched by the ISO at specified output limits for specified time periods to meet Load and/or reliability requirements that differ from or supplement the ISO's security constrained economic commitment and/or dispatch.

[3] Day-Ahead Reliability Unit (DARU) is defined as: A Day-Ahead committed Resource which would not have been committed but for the request by a Transmission Owner in order to meet the reliability needs of the Transmission Owner's local system which request was made known to the ISO prior to the close of the Day-Ahead Market.

[4] Supplemental Resource Evaluation (SRE) is defined as: A determination of the least cost selection of additional Generators, which are to be committed, to meet: (i) changed or local system conditions for the Dispatch Day that may cause the Day-Ahead schedules for the Dispatch Day to be inadequate to meet the reliability requirements of the Transmission Owner's local system or to meet Load or reliability requirements of the ISO; or (ii) forecast Load and reserve requirements over the six-day period that follows the Dispatch Day.

occur. Actions taken outside of the market are generally used as a reliability backstop when the market software does not adequately commit or dispatch the necessary resources to meet a particular real-time transmission constraint.

Operating a generator OOM can lead to situations where the market prices are not reflective of all actions required to maintain system reliability. Because the constraints that lead to OOM actions are not reflected in the NYISO's Energy and Ancillary Services market, NYISO's Location Based Marginal Prices (LBMPs) do not provide the investment signals necessary to incent the construction and maintenance of resources that can efficiently manage 100+kV constraints. Securing 100+kV transmission facilities in the commitment and dispatch software will both improve the overall market efficiency as well as provide better targeted investment signals.

Typically, uplift resulting from the NYISO securing facilities in its market solution is allocated statewide. Similarly, any generator uplift resulting from out of market actions taken by the ISO to ensure the reliable operation of the New York Control Area (NYCA) is allocated statewide. Generator uplift associated with TO requested out-of-market actions to secure the local system is allocated locally. If the NYISO begins to secure 100+kV facilities, this same logic will continue to apply.

Market rule changes will be necessary to address market power concerns if certain 100+kV reliability facilities are secured in the NYISO's DA and RT Energy Market software. As first identified in Federal Energy Regulatory Commission (FERC) Docket No. ER09-1682, and later in FERC Docket No. ER10-2220, the modeling of reliability constraints that can only be solved by one supplier in the LBMP-setting logic will expand the potential effects of that supplier's exercise of market power. The NYISO's current rest-of-state reliability commitment market power mitigation rules that were approved by the FERC in Docket No. ER10-2220 are based on imposing after-the-fact guarantee payment mitigation. The mitigation rules presume that the reliability constraint is not modeled and is not included in energy clearing prices. The modeling of new reliability constraints in the LBMP-setting logic that can only be addressed via the commitment and dispatch of a pivotal generator would need to be accompanied by new mitigation measures that go beyond the mitigation measures that were accepted by FERC in Docket No. ER10-2220.

In FERC Docket No. ER09-1682 Paragraph 16 of Dr. David Patton's affidavit stated:

> ***"…modeling a reliability constraint that only one supplier can satisfy…would simply shift the market power rent from the guarantee payment to the energy payment. The [additional] market power measure would still be needed…because the generator's Incremental Energy Bid would need to be mitigated to a competitive level that reflects the generator's marginal cost of producing energy."***

Section 10 of this white paper describes market power considerations.

3. Challenges

There are a number of benefits to securing 100+kV transmission constraints within the market model, but there are also a number of challenges that the NYISO has to resolve in order to move forward with a completed market design. The technical considerations identified below have the potential to impact the implementation timeline for this market design improvement.

Technical Considerations

This section identifies technical considerations that have been identified with significantly expanding the range of secured transmission facilities included in the market model.

- Computation size: the security constrained unit commitment and economic dispatch software contains matrices required for the processing and evaluation of transmission constraints. Expanding the range of secured transmission facilities in the market model will increase the scope and number of transmission constraints and the size of the matrices used in the dispatch software. Greatly increasing the matrices size could have an adverse effect on the software execution performance.
- Longer execution time: the execution time of the network analysis and the unit commitment/dispatch can each be affected by including additional secured transmission facilities that must be considered in developing a least-cost solution. Transmission constraints are also monitored by an engineer during the DA evaluation. Adding transmission constraints will affect the engineer's review time.
- Later posting of the Day-Ahead Market (DAM): the ISO currently makes a "best efforts" to post the DAM results by 9:30 a.m.; ahead of the required tariff posting deadline of 11:00 a.m.[5] The longer execution and review times will decrease the percentage of

[5] Posting the DA market results before 10:00 a.m. makes it feasible for some generators to procure natural gas in the DA natural gas market to meet their DA electric schedule.

days that the 9:30 a.m. posting can be achieved.

- Network Topology solutions: in some areas the TOs use line sectionalization or load switching in order to secure lower kV facilities. The current energy market software has no capability to evaluate these unpriced, transmission options and has to be modified to permit their incorporation. For line switching examples, please see Appendix A.
- Constraint volatility: portions of the 100+ kV system have large loads that randomly cycle based on industrial processes. In addition many resources on the 100+ kV system have limited or no ramp capability. The combination of these factors will likely lead to significant constraint price volatility, or the market systems will likely be temporarily unable to meet the reliability needs due to ramp constraints.
- Constraint Reliability Margin (CRM): The CRM used on most transmission facilities today is 20 MWs and the Graduated Transmission Demand Curve (GTDC) software has been designed for this. However the 20 MW CRM can be a significant percentage of a lower kV transmission facility's thermal rating. This will require changes to the GTDC to ensure it functions correctly with a lower CRM for lower kV circuits.
- Market Mitigation: The current Automated Mitigation Process (AMP) in the Security Constrained Unit Commitment (SCUC) and Real Time Commitment-AMP (RTC-AMP) is designed for NYC and Rest of State. Software design changes will likely be required in the SCUC-AMP, RTC-AMP and Reference Level Software (RLS) if constrained areas are identified in upstate New York as a result of securing 100+kV transmission constraints in the market model. As discussed in greater detail below, additional mitigation process will increase SCUC and RTC-AMP execution time.
- Transmission Constraint Shortage Pricing: Much of the 100kV system does not have local generation. When transmission constraints develop on this portion of the system, the resources available to the market software will have limited shift factors to resolve the constraint, which could result in significant shadow prices. This will require the NYISO to develop and implement revised GTDC software.

4. Market Efficiency of Securing the 100+kV System

In the energy market, the NYISO secures 230kV and higher transmission facilities, 138kV facilities in New York City (Zone J) and on Long Island (Zone K), and a single 115kV line, 1-910 Malone-Willis 115kV, in northern New York. These facilities are secured within the optimal solution of the market software. The flow on secured facilities is limited to their applicable ratings for normal and contingency conditions for the purposes of scheduling and pricing. When a secured transmission facility can no longer facilitate any more flow a binding transmission constraint is developed in the market solution and a shadow price is calculated for that transmission facility. The shadow price (or constraint cost) represents the reduction in system cost that would occur if one more megawatt (MW) of energy could flow over the constrained transmission facility. These constraint costs then become a component of the LBMP. LBMPs can vary by location based on each location's (or pricing node's) sensitivity to the transmission constraint. For example, if an injection of energy at a given node reduces the flow of energy over the limiting (constrained) transmission facility, then the LBMP at that node is increased by the amount of the constraint cost multiplied by the node's impact (or shift factor[6]) on the constraint.

At present, the NYISO generally does not secure 115kV and 138kV facilities within the market solutions for upstate New York areas. Instead, the 115kV and 138kV facilities are monitored by the TOP, and when these facilities become overloaded for normal or contingency conditions, they are secured through manual intervention (out of market actions). These processes may include the DARU or RT SRE commitment of units, OOM dispatch adjustments, internal or external interface de-rates, transaction cuts, or phase-shifter flow adjustments.

There are two potential market inefficiencies that arise from using out-of-market methods to address constraints on 100+kV facilities.

- Optimality: While the actions taken are necessary to reduce flow on overloaded facilities, in some cases they may not be the least-cost optimal adjustments that would be taken if the facilities were secured by the market software. Additional costs may be introduced to the market beyond the costs associated with an optimal solution.
- Price Formation/ Transparency: The costs associated with out of market actions to

[6] A shift factor explains the relationship between a location on the transmission system and a transmission constraint. Each location on the transmission system will have a unique shift factor for each transmission constraint. To determine the shift factor for location "A", a powerflow model would simulate injecting 1 MW of energy at location A and withdrawing 1 MW of energy at the reference bus (sometimes referred to as the swing bus) and measuring the change in flow over the transmission facility.

For example, if 1 MW of energy injected at location A and withdrawn at the Marcy (reference) bus resulted in a reduction in flow of 0.25 MW over the transmission constraint, then the shift factor would be 0.25.

secure underlying facilities are not explicitly represented in LBMPs as constraint costs (shadow prices) on the facilities being secured. As such, there is not an accurate accounting of the impact to system costs from the limitations imposed by this facility. By extension, the lack of a constraint cost for these facilities eliminates the proper LBMP impacts for nodes that are sensitive to this transmission constraint. The costs associated with out of market actions taken tend to be socialized across an entire Load Zone, or the entire NYCA, instead of being explicitly assigned to the nodes that have the greatest impact on the transmission constraint. The current approach mutes price signals for investment that would improve system reliability and efficiency. The absence of constraint costs reflected in LBMPs can have a chilling impact on investment in maintenance and new resource entry. Suppliers have no visibility into the potential revenue opportunities available to development, which inhibits least cost competition. Policy makers and local utilities cannot easily quantify the benefits of transmission solutions, which may delay or impede the development of low cost transmission options. The lack of supply and transmission options can result in the need for out of market reliability contracts, which may result in significant costs to consumers.

Examples of potential outcome differences: "Out of Market" versus "In-Market" security

Securing transmission facilities in the market model drives a more efficient solution for contingencies that are modeled. However, there are voltage and lower kV system constraints which are not part of the market model because some of these constraints cannot currently be accurately reflected in the market model. Securing 100+kV transmission facilities will have no impact on OOM actions and DARU commitments that are called to address factors that are not modeled in the market software.

Example 1: OOM "down" action

Facilities unsecured in the market solution

Due to overloads on a set of 115kV facilities in an export constrained area, generation located in the constrained area is sent an OOM "down" instruction to reduce output in order to secure the constrained transmission facilities. Because the market model did not incorporate the 115kV constraint, its constraint costs were zero. Therefore nodes sensitive to the 115kV export constraint do not reflect a direct LBMP price impact as a consequence of reducing generator output to resolve the constraint. The market software economically dispatches up energy in other locations to replace the energy that is no longer being produced due to the OOM down action. This may result in an increase in LBMPs across NYCA or in a portion of NYCA, but it will not send an appropriately targeted price (LBMP) signal.

Facilities secured in the market solution:

If the 115kV export constraint described above was included in the market model, then the overloaded facilities would be secured by the market software through redispatch of the most cost effective resources at the nodes or zones. An explicit constraint cost (shadow price) would be calculated and the LBMP and cost impacts would be appropriately assigned to the nodes or zones that are sensitive to the export constraint.

Example 2: DARU of a resource for RT Constraints

Facilities unsecured in the market solution

A unit is reliability committed DA to resolve a potential RT overload on the 115kV system. If the unit is otherwise uneconomic and dispatched at its minimum generation point, then it will be scheduled to meet the reliability need and appropriately displace other generation whether the constraint is modeled or not modeled in the market solution. Where the unit's costs exceed its LBMP and Ancillary Service revenues, the unit will receive uplift payments. Additionally, if this uneconomic resource operates at minimum generation, its operation can depress LBMPs, which could further aggravate local area uplift.

Facilities secured in the market solution

Though an initially economic resource can later be uneconomic and operate at its minimum generation point for a number of intervals, there are two potential benefits when the underlying transmission system is secured in the market model and the unit need not be reliability committed to address the posited 115kV constraint.

- The unit is committed economically to secure the overloaded facility. Constraint costs and associated local LBMPs in the market solution will settle at or above the cost of the resource, so the uplift is eliminated. This potential benefit assumes that the resource is capable of responding to five minute dispatch instructions in order to be an eligible price setting resource.
- The market software finds an alternative to the commitment of the resource to resolve the limiting facilities. This will both eliminate local area uplift and reduce total system cost.

5. Additional Benefits

As discussed above, securing 100+kV transmission constraints in the market model will produce more efficient prices, resulting in more efficient energy market incentives for both existing resources and potential new entrants. Absent these price signals, current resources may avoid efficient maintenance or investment in plant improvements, and potential new entrants to the market may choose to locate in an inefficient area or choose to avoid entry altogether.

The New York Public Service Commission (PSC) initiated its "Proceeding on Reforming the Energy Vision (REV)" on April 25, 2014 with the goal of aligning electric utility practices and the regulatory regime with technological advances in information management, power generation, and distribution. The objectives for REV include:

- Enhanced customer knowledge and tools that support effective management of customers' total energy expenditures;
- Market animation;
- Improved system-wide efficiency;
- Increased fuel and resource diversity;
- Enhanced system reliability and resiliency; and
- Reduced carbon emissions.

As part of this initiative and the NYISO's efforts to integrate Distributed Energy Resources (DERs) into the wholesale markets, it will become increasingly important to incorporate the impacts and the value of maintaining transmission system reliability, including the value for supporting the 100+kV facilities, into the wholesale electricity market prices.

Additionally, New York's Clean Energy Standard (CES) is intended to fight climate change, reduce air pollution and encourage low carbon energy supply. To achieve these goals the CES requires that 50 percent of New York's electricity come from renewable energy sources by 2030. A large benefit to modeling the 100+ kV systems is to provide DERs, which will be integrated into the market at lower kV levels, appropriate price signals to make informed investment decisions. Providing improved price transparency on the lower-voltage components of the transmission system will help to attract DERs and other energy efficiency and renewable resources, which will allow the NYISO to help New York meet the requirements of CES.

6. Procedural Modifications

As described in the Challenges section above, there are a number of factors which limit the NYISO's ability to secure every 100+kV facility in the NYCA. A transparent process for identifying and securing certain 100+kV constraints must therefore be defined. The resulting set of transmission constraints should be developed to produce the most efficient possible outcome, given the limitations preventing the securing of all 100+kV constraints.

The NYISO will modify its procedures to evaluate 100+ kV facilities to be secured in the market model in a manner consistent with its legacy constraint modeling efforts. Key components of the methodology NYISO will use to identify and secure new lower kV reliability constraints in the DA and RT Energy markets are set forth below.

- Identify candidate transmission constraints, including applicable contingencies
- Verify expected transmission constraint flows in the DA and RT Energy market models
- Identify generators with adequate shift factors to resolve candidate transmission constraints
- Determine if there are market power concerns when securing the new constraints
- Develop process for notifying NYISO Stakeholders of DAM/RTM modeling changes to implement lower kV constraints

Identify candidate lower kV constraints

On a daily basis, the ISO will review the need for out of market actions being taken, such as a generator that is subject to a DARU, SRE or OOM by the ISO or at the request of the local TO. The NYISO will also review, on a daily basis, the modification of limits for external and/or surrogate transfer limits, the use of PAR controlled lines, and other similar actions. On a seasonal basis, the ISO will review the Summer and Winter Seasonal Operation Study to observe if new lower kV constraints have become more limiting. On an as-needed basis, at TO request, the ISO will review any changes to the Application of Reliability Rules (ARRs)[7] that the TOs submit to determine if a new lower kV constraint should be considered for incorporation into the market model.

[7] ARRs are developed to comply with the New York State Reliability Council's Reliability Rules that apply to specific system locations or conditions.

Verify transmission constraint flows in the energy market models

Once identified, the ISO will validate that the energy market model can accurately represent the transmission constraint within a tolerance as identified by the CRM of 20 MWs for on and off peak periods. The 20 MW CRM will need to be modified for lower kV facilities. If changes are required to the network model to effectuate the transmission constraint flows, the changes will be implemented in a subsequent energy market model update, which occurs approximately every other month.

Identify generators that are likely to be dispatched to resolve a newly developed transmission constraint and determine if the generator(s) need to be made subject to additional market power mitigation rules

The NYISO will identify generators that could exhibit market power and develop appropriate mitigation measures.

Notification to Stakeholders

The ISO will notify stakeholders of the expected implementation of new lower kV reliability constraints including the expected market day that the change will take effect. The NYISO expects to identify those 100+kV facilities that are secured in the market model through an attachment to the Outage Scheduling Manual.

7. Historical Review of Upstate Power Supplier Guarantee Payments

In order to better understand the potential benefits of the proposal, the NYISO has reviewed power supplier guarantee payments for the last five years associated with local, upstate 100+kV reliability operations. The NYISO expects that some portion of these power supplier costs could be reduced by modeling certain upstate 115kV transmission constraints and producing higher energy market clearing prices.

It is unlikely that all apparent inefficiencies associated with local 100+kV reliability operations can be eliminated because (a) many of the power suppliers that are capable of resolving local constraints are not dispatchable (they are not flexible price setting resources), and (b) some of the reliability constraints cannot be adequately represented in the market models (e.g. local voltage constraints). Nevertheless, this review provides an estimate of the potential benefits of modeling upstate 100+kV constraints.

From 2012 through 2016, local reliability power supplier costs have ranged from $14M to $26M/year. For 2012 and 2013, supplier costs were approximately $14M/year. Supplier costs increased to $20M/year in 2013 and reached a high of $26M/year in 2014. The following discussion details the significant year-over-year cost drivers.

Summary of Historic Zonal Power Supplier Costs for Local Reliability:

2012: $14M total - West Zone ($6M), Genesee Zone ($3M), Central Zone ($3M)

2013: $14M total - West Zone ($7M), Genesee Zone ($2M), Central Zone ($3M)

2014: $20M total - West Zone ($10M), Central Zone ($8M)

2015: $26M total - West Zone ($14M), Central Zone ($10M)

2016: $16M total - West Zone ($1M), Genesee Zone ($1M), Central Zone ($14M)

In order to evaluate the expected levels of local reliability power supplier costs for future years, the following factors were recognized:

- In December 2015, National Grid's Five Mile Road substation entered service. Since entering service, Five Mile Road has mitigated the need for the Dunkirk plant and has largely mitigated the need for operation of the Indeck Olean plant. This transmission upgrade has significantly mitigated the primary driver of West Zone generator commitments to address local reliability concerns.

  The primary drivers were thermal and voltage constraints in Southwestern NY. ARR 35 describes one of the current local needs as "VOLTAGE SUPPORT IN SOUTHWEST REGION." During system conditions where any one of the Dunkirk 230/115 kV or Five Mile Rd. 345/115 kV autotransformers is out of service, Indeck Olean should be committed to reduce loading on autotransformers that may remain in service as well as to help support post–contingency voltage.

- By June 2017, NYSEG and National Grid system upgrades will significantly mitigate the primary driver of Central Zone generator commitments (primarily of the Milliken plant) to address local reliability concerns. The Operations Monthly report for April 2017 identifies ARR-29 as the primary driver for the Central commitments. ARR-29 requires that during heavy load and certain maintenance conditions, at least one Milliken / AES must be in service pre-contingency to avoid overloads on certain 115 kV lines.

8. Transmission Congestion Contract (TCC) Market Implications

Continuing its current practice, the NYISO will initialize the TCC market model using the transmission system representation, including transmission limits, with the NYISO model for the DAM SCUC. Change in security status for 100+kV transmission elements in the DAM evaluation will propagate to the TCC market model and these transmission elements will likely be limiting for TCC constraints. The TOs will likely realize changes to TCC Auction revenue resulting from release of Existing Transmission Capacity for Native Load, Net Auction Revenue allocation, and to payments or credits associated with transmission equipment status changes, as represented in the TCC Auction or through the DAM Congestion settlements. All outages of transmission facilities, including 100+kV elements, will be evaluated for cost impact in either the TCC Auction or the DAM Congestion settlement process. Introducing 100+kV secured facilities will likely increase the magnitude of outage cost impacts due to TCC and DAM constraints involving these transmission elements.

9. Study Model and Interpretation of Results

In order to better understand the potential market outcomes, the NYISO performed a series of DAM simulations with upstate New York 100+kV transmission facilities secured in the market solution.

In the NYISO energy markets, the 100+kV facilities are not secured as part of the real-time market solution. Instead, where overloads occur on these facilities in real time operation, manual actions are taken to reduce flow on these facilities. 100+kV facilities are not secured in the DAM model. Overloads may exist in the solution but SCUC does not take any "action" to secure these facilities. Therefore, the initial approach to understanding the effects of securing the 100+kV system in the market solution is to modify the DAM model to secure the overloaded facilities in a least-cost, optimal manner.

Simulations utilizing the DAM model, while providing a more direct expectation of the impact of securing 100+kV facilities in the DAM, should be recognized as only a proxy for the potential RT outcomes. An understanding of the fundamental differences between the models is necessary in order to reasonably infer potential RT outcomes from DA solution results.

In general, the DA model has a greater degree of flexibility in forming the least-cost optimal solution, including on/off resource status, full dispatch flexibility, variable load and transactions. For the purposes of this study, important elements with respect to assessing the DAM results as a proxy for real time is the variability of load as a function of virtual transaction offers and the DA assumptions with respect to Lake Erie circulation.

In market areas that experience real-time, high price volatility, the DAM model will often include a larger set of virtual transactions which tend to push the persistence of transmission constraints across multiple hours. That is, the nature of the offer supply curve may result in virtual load continuing to clear until transmission limitations force incremental costs to rise (the converse is true for virtual supply). Secondly, the Day Ahead model over the study period includes a strong clockwise bias in Lake Erie circulation, which tends to further push the persistence of transmission constraints. However, the added degrees of flexibility (a larger number of market variables available to resolve these transmission constraints) in the DAM generally means lower average constraint costs. Should the proposed 100+kV modeling improvements be implemented, it is likely the profile of virtual offers would differ in both volume and price points. Such modifications could have significant impact on the potential DA pricing results.

In contrast, the RT market does not have as many degrees of flexibility as the DAM. For instance, at the RTD level, load is fixed quantity, as are transactions and non-10-minute resource commitments. In addition, available dispatch may not have the full ideal range found in the DAM. The RT market does not have a variable market load component that can either drive or resolve transmission constraints. Lake Erie circulation is highly variable in RT and may include both clockwise and counter-clockwise flows across the day. As such, the RT market will generally not see a transmission constraint persist over multiple hours, as might occur in the DAM. The same transmission constraints tend to materialize in RT that arose in the DAM, but less frequently as a percentage of time. Because the RT market is more "confined" in terms of the market solutions available to resolve overloads, when a transmission constraint develops the NYISO typically experiences higher constraint costs (shadow prices) due to the more limited range of solutions available to resolve the constraint.

Study Results – Day-Ahead Market Simulations (June 23 – Nov. 2, 2016)

Market Model

Within the DAM market models from June 23 to November 2, the underlying 115kV systems, principally in the West, North and Central were secured to STE (Short Term Emergency), including a CRM value for contingency conditions. The principal areas represent locations where real time actions to secure the underlying system are most frequent. The balance of the underlying network was only selectively secured, but was monitored in full for any potential security violations. Due to resource and time constraints, the software was not able to be modified to account for anything other than a 20MW CRM on the facilities. As noted earlier, 20 MW is likely too restrictive for 115kV facilities.

115kV Constraints

Table 1 though Table 4 below illustrate the most prevalent 115kV constraints found over the study period. The constraints identified in the study were consistent with the set of facilities that have required real-time operator actions (or DA commitments) to secure. For each transmission constraint, the line segment, total hour count and average shadow price over those hours are shown. While several of these constraints occurred during normal conditions (all lines in), the hour counts for many of the constraints was strongly influenced by network outage conditions. As such, the hour count for some constraints was accumulated over fairly short stretches of time. The footnotes for each table describe the outage conditions which strongly influenced a particular transmission constraint.

Discussion of West Transmission Constraints

The West transmission constraints are detailed in Tables 1 and 2. Table 1 shows the Packard to Gardenville 115kV lines (181/182) to be the most prevalent West constraints. The majority of hours for these constraints is associated with the loss of the Packard 230kV Tower (77/78 Lines). This contingency transfers flow from the 230kV system to the underlying 115kV system. A subset of these constraints results from the loss of the parallel facility (e.g. loss of 182 on 181). The strongest driver of these transmission constraints is the base flow associated with high Niagara East 115kV generation – where Niagara East 115 connects directly to the Packard – Gardenville 115kV lines via the 191/192 lines.

Simulations performed on a small subset of days with Niagara output shifted to the 230 or 115 West injection points tends to move the dominant constraints to facilities connected to those injection points, such as the 230kV facilities (Niagara-Packard, Packard-Sawyer), the Niagara 230/115 transformers and the Packard-Huntley 115kV lines.

The second most prevalent set of West transmission constraints are the facilities between Packard 115kV and Huntley 115kV. The associated contingencies are the loss of the Packard Tower or the loss of the parallel facility (e.g. 129/133 on the 130).

The Gardenville 115kV to Dunkirk 115kV (141 Line) constraint occurs in RT operations principally during periods where the Erie-S. Ripley 230 kV tie to PJM is in service. Placing the tie in-service increases flow from Gardenville 230 to Dunkirk 230 over the 73/74 Tower, which creates unsolvable reliability violations. The loss of this tower triggers the constraint as flow is transferred to the underlying 115kV system out of Gardenville.

The NYISO is currently evaluating proposed transmission projects to address the Western New York Public Policy Transmission Need. If a project is selected to proceed, it is likely the results presented here would be different and it is possible that some of these constraint costs may no longer arise upon successful completion of the public policy transmission projects.

Table 1 – West 115kV Constraints

Constraining Element	Hour Count	Avg. Shadow Price
181 Packard-Gardenville		
Packard-Niagara Blvd.	913	$215
Frankhauser-N.Broadway[1]	28	$426
N.Broadway-Erie St.[2]	10	$187
182 Packard-Gardenville		
Frankhauser-Walden[3]	177	$640
Grand Island-American Std.	33	$120
141 Gardenville-Dunkirk		
Gardenville-Cloverbank[4, 5]	136	$424
129/133 Packard-Huntley		
Walck Rd.-Zimmerman	210	$198
130 Packard-Huntley		
Packard-Zimmerman[6]	67	$159
191 Niagara-Packard[7]	39	$80
192 Niagara-Packard	14	$82
AT1 Niagara 230/115[8]	80	$175
BK3 Packard 230/115[9]	41	$164
103 Niagara-Swan Rd.[10]		
Niagara-Mountain	26	$58
Mountain-Swan Rd.	50	$92
38 Huntley-Gardenville[11]		
Huntley-Bufalo129	13	$546
[1] Oct. 6-7: 66/182 out		
[2] Oct. 27: 66/182 out, 68 in		
[3] Oct 10-21: 66/71/AT2/921 out		
[4] June23-27: Off-hour VL; Oct 4-5 & 25-27: 68 in; Oct. 31: 71/133/903 out		
[5] Several hours associated with Five Mile 345/115 outage		
[6] Oct. 31: 129/133 out		
[7] Aug. 18-21: 192, 101 out		
[8] Oct. 6-14: 66/71/AT2 out		
[9] Packard BK3 held to STE; Aug. 17-19: 192, 101 out; Sep. 12 -13: AT1, 70 out		
[10] Jun. 27: 181-922 out; Jul. 16, Aug. 1-3: 102, 101 out		
[11] Oct 10: 66/71/AT2/921 out		

Table 2 describes the 230kV West constraints, where the original production cases are compared to the 230kV constraints found over the study period. The table illustrates that when the underlying 115kV system is secured in the market solution, constraints on the newly secured facilities become the dominant set of transmission constraints in the West. In particular, there is a strong shift from Packard-Sawyer 230kV to the 115kV system.

Table 2 - Change in West 230kV Constraints

Constraining Element	Hour Count	Avg. Shadow Price
Production[1]		
Niagara-Packard	585	$54
Packard-Sawyer	590	$103
Gardenville-Stolle	174	$39
100+kV Security Case[1]		
Niagara-Packard	462	$57
Packard-Sawyer	87	$99
Gardenville-Stolle	52	$45
[1] Hour count where Lambda >$5.00		

Discussion of North Zone/Upper Mohawk Transmission Constraints

Table 3 shows the North Zone/Upper Mohawk constraints found during the study period. With the 115kV in the North and Upper Mohawk areas secured in the market solution, the prevalent constraints over the study period are the Browns Falls – Taylorville 115 Lines (3 or 4 Line). The bulk of the constraints on these lines occurred during extended outages of either the 3 or the 4 Line. The balance of constrained hours can be attributed to high load conditions or to virtual supply schedules that pushed the limits of the facilities.

The modeling of the security of the 115kV North Zone and Upper Mohawk facilities effectively adds new limitations to the export of energy from this portion of the system, which includes numerous small hydro units and wind resources. The inexpensive nature of these resources, when coupled with a reduction in dispatch to secure the 115kV system, may yield relatively high shadow prices for these facilities.

Table 3 – North/Upper Mohawk Constraints

Constraining Element	Hour Count	Avg. Shadow Price
3,4 Browns Falls-	480	$72
1 Higley-Browns Falls	104	$116
2 Flat Rock-Browns Falls	7	$101
[1] Extended outages of lines 3 or 4 within study period		

Discussion of Central Zone Transmission Constraints

Table 4 lists the Central zone 115kV constraints found over the study period. The constraints that developed on the facility with the highest hour count (Cortland - Clarks Corner) were confined to a small number of days with extensive local outage conditions.

Over the study period, Milliken was frequently DARU committed due to potential constraints on the 115kV system, in particular, the Elbridge-State 115kV facility. Securing the 115kV system in the Central zone results in a fairly small number of hours (68) where this facility is binding. The binding hours may be sub-divided between Milliken providing marginal energy to off-load the facility versus hours where other shifts in the system are deemed more economic to off-load the facility (while Milliken remains at Min Gen). Transmission expansion in this area of the system is already underway in order to permit the Milliken units to retire.

A number of days across the study period were assessed without any Milliken units committed in the Day-Ahead for reliability, but with the 115kV system secured in the market solution. The objective was to assess the extent to which Milliken may be economically committed to resolve the constraint and the resulting local prices. Simulations indicate that Milliken would only be committed in a small number of days across the study period to resolve the constraint. Milliken was committed economically when local outage conditions yielded little alternative other than very high cost transmission relaxation. Commitment of Milliken was also necessary on several of the highest load days. Under these circumstances, local market prices were sufficient to cover Milliken's costs. However, for the bulk of the days over this period, economic alternatives to the Milliken commitment were found by the market software. In either scenario, the bulk of uplift costs were eliminated by securing the 115kV system in this zone. As noted earlier, by June 2017, NYSEG and National Grid system upgrades will significantly mitigate the primary driver of Central Zone generator commitments (primarily of the Milliken plant) to address local reliability concerns.

Table 4 – Central Zone Constraints

Constraining Element	Hour Count	Avg. Shadow Price
716 Cortland - Clarks		
Cortland -Tuller	72	$188
Tuller Hill - Clarks	45	$198
972 Elbridge-State St.[2]	68	$113
23 Quaker Rd. - Station	25	$242
982 Codington- Montour	16	$57
[1] **Count total exclusive to Oct 10-13 due to multiple outages**		
[2] **Milliken DARU**		

Discussion of Constraining Elements in other Zones

The monitoring of 115kV facilities in the Capital Zone indicated frequent overloads of the Albany-Greenbush and Albany –Trinity 115kV facilities. While these lines represent constraints requiring real-time operator actions to secure, it was found that issues with the underlying network modeling were the likely cause of most of the overloads in the simulation. Specifically, the Albany bus was modeled in a different configuration than is utilized when local resources are committed. As a result, the facilities were not secured in the market solution. Even after this modeling concern is addressed, experience in real-time operations suggests that these facilities would, at times, be constraining. Accurately modeling the expected configuration of the Albany bus in the market software would require that the network topology be re-evaluated after each unit commitment evaluation, which would require NYISO to develop significant new software functionality.

Generation Shifts

Securing the underlying 115kV system introduces new constraints across the study period which drive generation pattern shifts. Table 5 illustrates the month by month changes in average hourly schedules by zone.

The study finds the West and North Zones increasingly export constrained with lower average schedules as compared to the original production cases. The net decrease in generation schedules in these areas is balanced by two sources:

- A net decrease in virtual load, principally in the West, due to an increase in local incremental costs; and
- A net increase in imports, and to a lesser extent, increases in internal generation in other areas. The largest offset to the West generation decrease is an increase in

imports from PJM (which tends to off-load West constraints) and from Ontario, which has a less direct effect on the 115kV West system as compared to the 230kV system. The remaining energy deficit is supplied by resources in the East, principally in NYC.

A strong decrease in West schedules was found in October1, but was entirely due to a short stretch of days where a set of simultaneous outage resulted in near infeasible conditions, which were accounted for by incorporating high cost transmission relaxation.

Table 5 – Average Hourly Generation Shifts (MW)

Area	July	August	Septemb	October[1]	October[2]
West	-106	-100	-117	-233	-170
North/C	-16	- 5	-11	-5	0
NYC	+7	+4	+13	+21	+14
Capital	+6	-2	+4	+3	+1
PJM	+31	+61	+52	+162	+88
IESO	+21	+22	+14	+23	+26
[1]Difference due to simultaneous outages requiring high levels of transmission relaxation; Oct					
[2]Differences with data for Oct 10-14 removed					

System Costs

The study finds that securing the 100+kV transmission system in the market solution results in a small average daily increase in total system cost. This is an expected result in as much as securing additional facilities present new limitations to the economic flow of energy in the market model.

Figure 1 illustrates average daily change in total system cost and the percentage change in total system cost for each month. For the peak months of July and August the average daily change in total system is approximately $45K. Two values are shown for October. The higher level includes the effects of a set of near infeasible simultaneous outages in the West and Central zones during Oct. 10 -14. The second, lower value for total system cost change excludes those days from the calculation.

The objective of the market solution in DA is to minimize Total System Cost, where non self-scheduled supply resources (including virtual supply and imports) are a positive cost and pricecapped load (including exports) is represented by a negative cost.

The increase in total system cost is comprised of two main components:

- The largest share is comprised of a reduction in virtual load in the West. Within the market solution, securing the 115kV system in the West raises the local incremental costs of supply and reduces the amount of virtual load that is cleared.
- The average reduction in schedules in the West and North zones is replaced by energy from imports and internal NYCA generation that is slightly more expensive.

An important adjustment that must be factored into the assessment of total system cost is the presence of Milliken as reliability committed unit throughout the study period. Simulations over this period indicate that Milliken might not be committed economically over the majority of this period if the 115kV system were secured in this area in the market solution. Factoring in the cost savings if Milliken was not committed to secure the system would reduce the total system cost deltas in Figure 1.

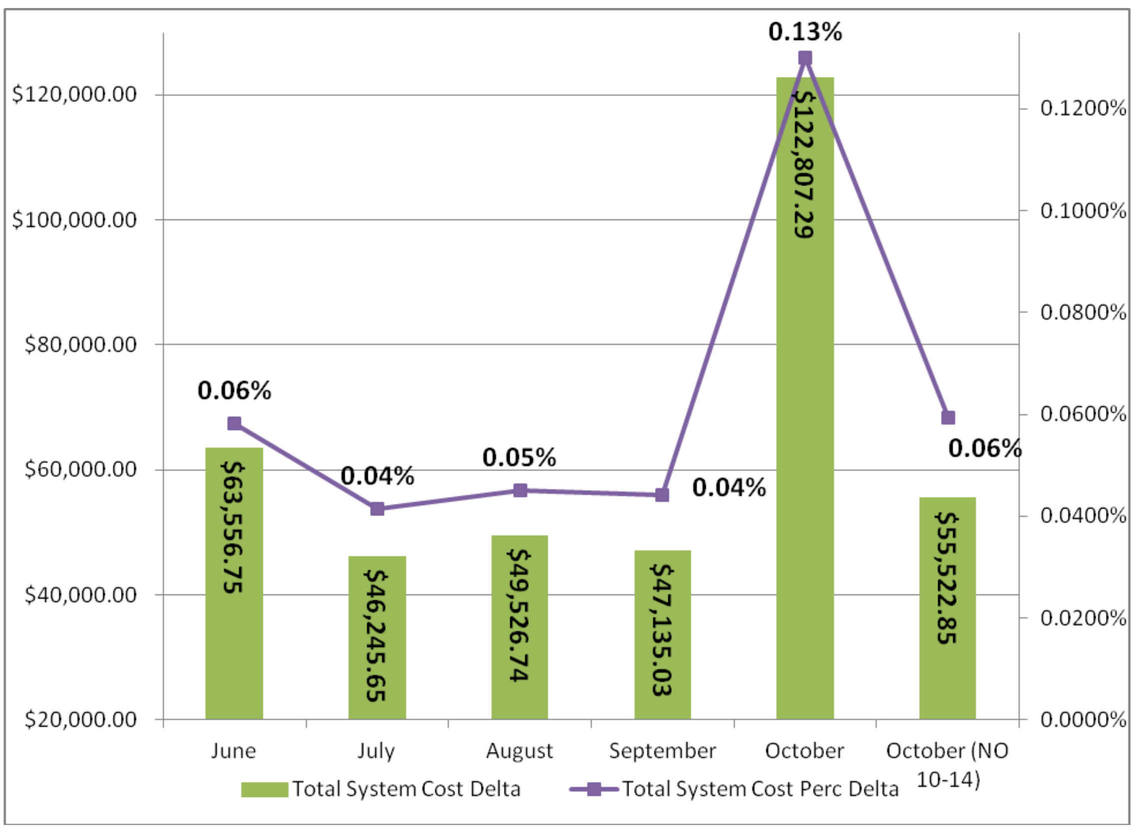


Figure 1 – Total System Cost: Average Daily Change by Month

Energy Prices

Figure 2 compares the average zonal price for the original production cases and the study cases in which 100+ kV systems have been secured in the market solution. As indicated by the chart, the West Zone sees the largest average increase in price. Within the market solution, securing the 115kV system in the West raises the local incremental costs of supply and reduces the amount of virtual load that is cleared. This results in virtual load clearing at higher price point on the supply curve, which in turn, raises average prices. However, the market rule revisions that NYISO will make to secure 100+kV transmission constraints in the market model have the potential to influence virtual trading and generation offer behavior.

Securing the underlying system in the North Zone results in a slight decrease in average hourly price. As an export constrained area, the additional 115kV limitations tend to reduce schedules and hence the internal marginal generation cost. In the Day-Ahead, this may include the reduction of physical resources such as hydro units, as well as virtual supply which clears lower in the supply curve. In real-time, the market shifts to wind as the primary flexible resource which would most likely price constraints that materialize.

The study finds little price change in other NYCA zones.

The LBMP changes found in this study are a function of market participant behavior over the study period where the underlying system was not secured in the market solution. However, it is reasonable to expect that securing the underlying system will influence market participant behavior. As such, the study results may be interpreted as representing potential directional changes in prices, but may not reflect the absolute LBMP differences that should be expected.

Note on Figures 2 and 3:

The West and Central zones experienced a 5 day period in October where a set of simultaneous outages created near infeasible solution conditions with the 115kV system secured in the market solution. This resulted in a set of very high price transmission demand curve constraint costs (shadow prices) ($2350) in the West and lower, but persistent transmission demand curve constraint costs in Central – yielding high zonal prices. The outages likewise fostered real-time actions on the same constraining elements over the affected days. Figures 2 and 3 exclude the prices from these days in the average zonal and proxy bus LBMPs for the month. While actions were taken by Operators to maintain reliability during this time period, the results here may indicate additional underlying modeling work is needed before pricing these facilities.

Figure 2 – Hourly Average Zone LBMP Changes by Month

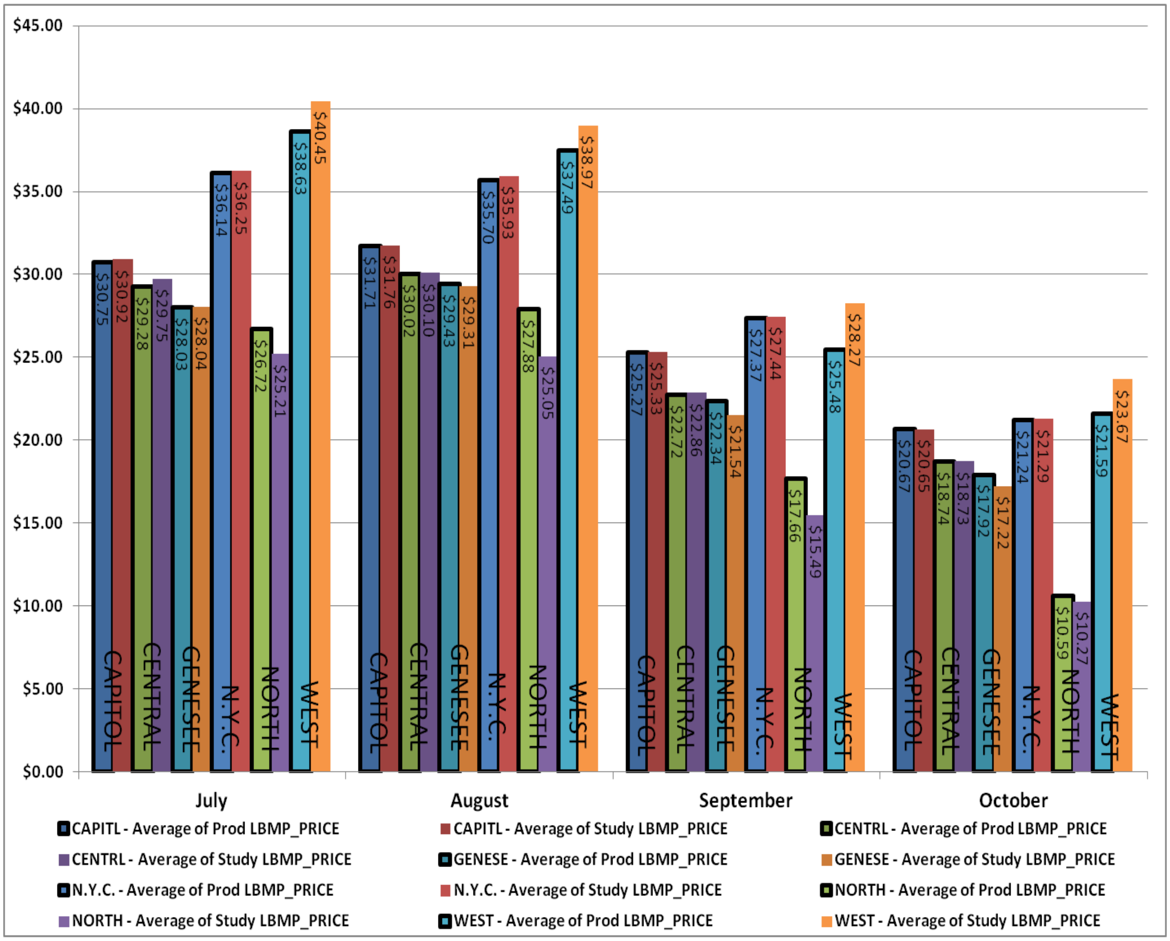
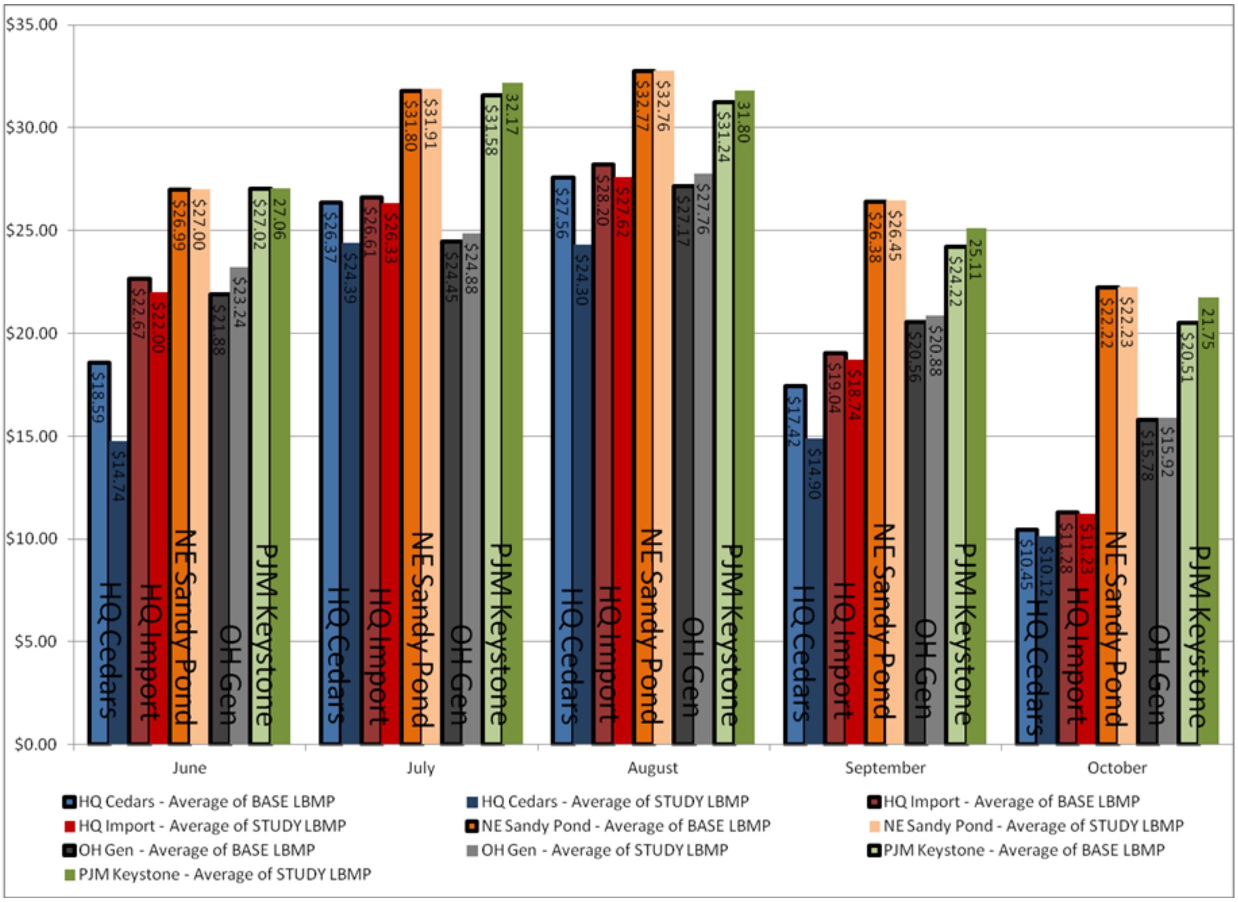


Figure 3 – Hourly Average Proxy Bus LBMP Changes by Month



10. Market Power Considerations

Currently, the NYISO manages market power concerns for generators needed to resolve 100+kv constraints using the Rest-of-State reliability mitigation rules. The mitigation measures only apply to generators that are committed via a DARU or SRE. Additional OOM dispatch above a DARU or SRE commitment is also subject to mitigation. Currently applied mitigation measures are described below.

Rest-of-State (ROS) Reliability Mitigation:

The NYISO applies specific mitigation measures to exercises of market power by Generators that are committed “outside the ISO’s economic evaluation process to protect NYCA or local area reliability” in the rest-of-state area. Specifically, the measures apply to a Generator committed as a Day-Ahead Reliability Unit (“DARU”) or via a Supplemental Resource Evaluation (“SRE”), or committed as a DARU or via SRE and subsequently dispatched Out-of-Merit (“OOM”) above its minimum generation level to protect or maintain NYCA or local reliability. The NYISO first determines that a Supplier is in a position to exercise market power by requiring that one of the following three conditions be met:

i. the Market Party (including its Affiliates) that owns or offers the Generator is the only Market Party that could effectively solve the reliability need for which the Generator was committed or dispatched, or

ii. when evaluating an SRE that was issued to address a reliability need that multiple Market Parties' Generators are capable of solving, the NYISO only received bids from one Market Party (including its Affiliates), or

iii. when evaluating a DARU, if the Market Party was notified of the reliability need for its Generator prior to the close of the Day-Ahead Market.

If a Generator meets one or more of the above three conditions, the mitigation measure specifies relatively restrictive conduct thresholds for assessing the Generator's Bid relative to the applicable reference level. The following thresholds are used:

i. exceeded the Generator's Minimum Generation Bid reference level by the greater of 10% or $10/MWh, or

ii. exceeded the Generator's Incremental Energy Bid reference level by the greater of 10% or $10/MWh, or

iii. exceeded the Generator's Start-Up Bid reference level by 10%, or

iv. exceeded the Generator's minimum run time, start-up time, and minimum down time reference levels by more than one hour in aggregate, or

v. exceeded the Generator's minimum generation MW reference level by more than 10%, or

vi. decreased the Generator's maximum number of stops per day below the Generator's reference level by more than one stop per day, or to one stop per day.

Currently, if the above provisions are met for a Generator in the rest-of-state area, no impact test is required. The NYISO substitutes a reference level for each Bid, or component of a Bid, for which the threshold specified above is exceeded.

However, the NYISO will have to further consider how impact determinations should be conducted, from both market design and software system design perspectives. Securing the underlying 100+kV system has the potential to introduce new constraints and hence new "sub-areas" of the market. Where these sub-areas include a limited number of resources that are capable of resolving constraints, the potential for market power exists. The NYISO believes that, as a starting point, the ROS Reliability Mitigation conduct rules should be extended to resources scheduled to alleviate or solve a 100+kv constraint.

Two topological conditions that likely will lead to market power have been considered for review:

- Import constrained “load pockets” where a limited number of internal resources are capable of resolving the constraints and serving internal load.

  This study has identified one potential import constrained load pocket that may result from binding constraints on the underlying 115kV system; the Gardenville-Cloverbank (141 Line) constraint. Analysis indicates a strong potential sensitivity of offer to price for resources in this load pocket.

  Conservative facility ratings (including the NYISO CRM) contribute to the potential for the Gardenville-Cloverbank (141 Line) to bind. Tests conducted where the facility is subject to a smaller CRM, which is more appropriate for lower voltage facilities, significantly reduces the constrained hours.

- Resources on the high priced side of a constraint located in export constrained sub-areas, where a limited number of resources will likely strongly influence the constraint and hence export capability of the sub-area. This type of topological condition potentially exists in both the West and North zones.

  Assessing the potential for market power to be exerted under these circumstances is more complex. The ability for resources on the high priced side of a constraint to influence local price is not only a function of its own sensitivity to the constraints, but also a function of the offers from resources on the low priced side of the constraint and the respective sensitivities of the resources being used to resolve the constraints.

In these cases, the potential for market power can be assessed by first establishing the maximum price “spread” for each local price over a variety of network and market conditions where:

- Maximum: Full withholding of resource
- Minimum: Resource fully dispatched at cost

Price Spread

Secondly, an assessment is made of the extent to which a resource could exert a measure of local price control.

Analysis to date indicates that under normal conditions (all lines in) the ability for resources on the high priced side of the constraint to exert price control is limited. However, certain outage conditions will likely increase the sensitivity of local price to resource offers for some resources/locations. Further analysis will be required to establish sensitivities of price to offer under these scenarios as well as further discussion on appropriate thresholds at which market power might reasonably be expected to exist. This analysis must include consideration of whether the current market power rules are adequate to address this behavior, or if rules, such as Uneconomic Overproduction, need to be modified.

As the NYISO has identified at least one area with the potential for market power under the new solution, new rules must be implemented to mitigate the potential impact of market power in these situations. The NYISO's current AMP software does not allow for the creation of mitigated load pockets outside of NYC. As such, the NYISO will need to work with stakeholders to identify the most effective method(s) for introducing this type of mitigation into the market systems. Some potential options for consideration include:

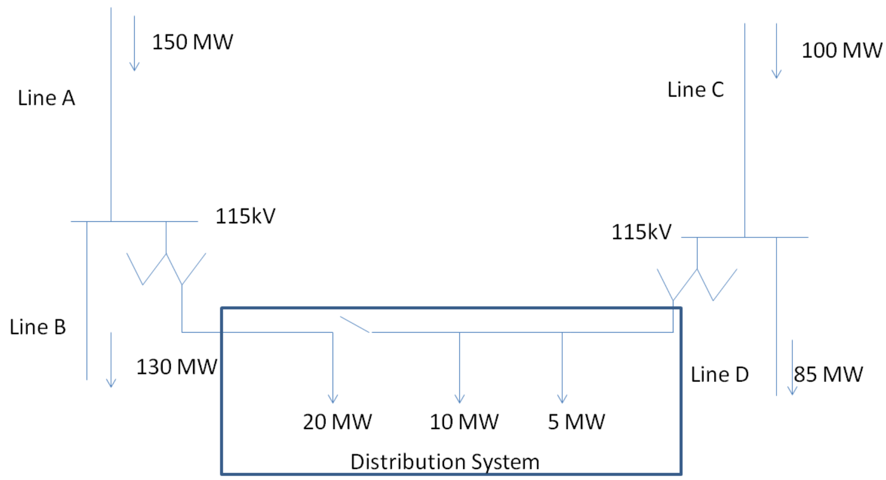
- Modify the current definition of a "Constrained Area" and extend a version of the current AMP rules to the locations where NYISO has determined that transmission constraints give rise to significant locational market power. The benefit of this approach would be both consistency of rule sets across locations, as well as advanced transparency into mitigated locations. However, this would like require extensive software modifications to the NYISO's market systems.
- Create the capability for dynamically identifying constrained areas where market power concerns exist for the purposes of applying mitigation. The benefits of this approach would be the potential for easier implementation and the ability to reduce the impacts of market power in a timelier manner. However, this method would provide little to no transparency of mitigated localities until the mitigation occurred.
- Another option would be to mitigate without employing an impact threshold. Units identified as having the potential for market power in these areas would have a conduct test applied before the market systems run, at a zero impact threshold, such that they would always be mitigated to costs should they exceed the given conduct threshold, regardless of impacts to the market place. This would likely be the easiest method to implement. However, this would potentially result in resources being mitigated when there is no impact to consumers.

11. Recommendation

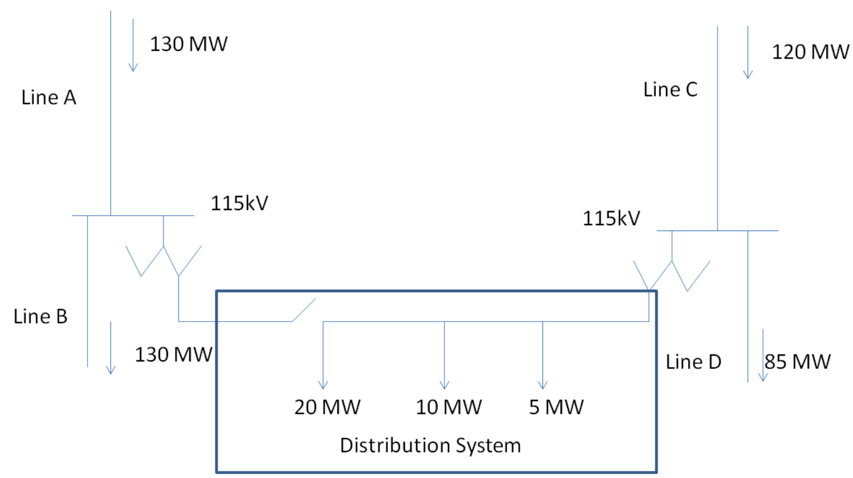
Securing 100+kV lines in the NYISO's market model will provide increased price transparency which will provide better investment incentives and will lead to more economic commitment and dispatch. Furthermore, securing these transmission constraints will become increasingly important as additional DERs are added throughout the state which would be connected to lower voltage subtransmission and distribution systems. The NYISO therefore recommends moving forward with a market design effort to secure select 100+kV constraints within the market model. Towards this end, the NYISO will begin working with market participants and stakeholders to further the market concepts and procedures necessary to support securing select 100+kV transmission facilities, including modifications to the transmission constraint pricing and market mitigation designs.

Appendix A: Line Switching Examples

Example 1:

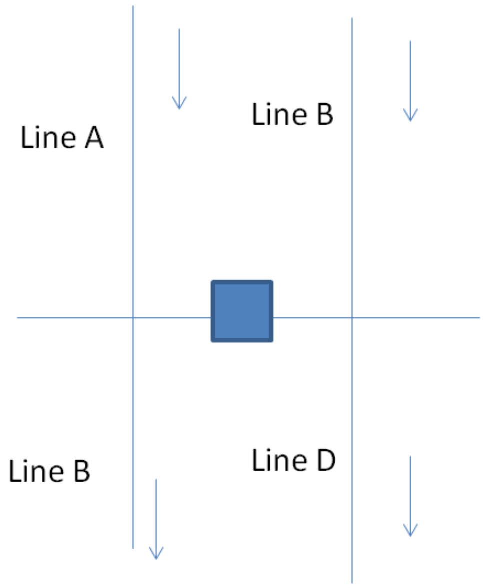


Normal Configuration Line A is over the post contingency rating for loss of Line D

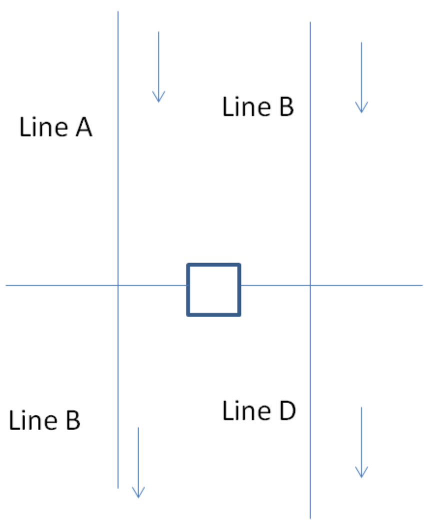


Alternate Configuration to alleviate Line A is over the post contingency rating for loss of Line D

Example 2:



Normal configuration Line B over Post Contingency Rating For loss of Line D



Alternate configuration is to open the Bus Tie breaker to alleviate Line B over Post Contingency rating For loss of Line D