March 5, 2015

<u>Responses to SSC Comments on January 30, 2015 Draft Report</u>

1. There were two requests for the pipeline utilization maps to show downstream pipelines that are constrained by upstream limits. Instead of using just red and grey, perhaps the downstream pipes could be yellow? The requests noted the New England system in particular.
   Response: The purpose of these maps is to identify the constrained segments rather than the segments affected by the constraints. This distinction is discussed on pages 108 to 110 with example maps of locations with affection generation (Figure 70) versus constrained pipeline segments (Figure 71).
2. There were two requests for commentary on how recently announced or approved projects might change the constraints found in the study. While it was pointed out that additional analyses would be difficult considering time and budget constraints, perhaps a qualitative analysis could be included in the report?
   Response: Potential impacts of incremental expansion projects are discussed in Section 8, Constraint Mitigation.
3. For the postulated loss of IP2/3, counsel for NYC inquired why the gas burns on the New York Facility System and elsewhere in NYISO changed significantly from the 6/20/14 preliminary report distributed to stakeholders before the June 2014 SSC meeting in Atlanta and the 9/30/14 draft report.
   Response: In consultation with NYISO and the other PPAs, certain model inputs to AURORAxmp changed during Q3-2014 to support completion of the 9/30/14 draft report. The changes in gas burns across NYISO are a product of those model refinements.
4. Comments from ConEd:
   a. Redispatch – We understand that the assumed generator dispatch was economically driven and the potential to redispatch the electric system to reduce gas use was not examined. There should be a paragraph in the executive summary making clear that the constraints on the gas system would not necessarily affect electric reliability and that further analysis would be needed to make that determination.
      Response: The following was added to the Executive Summary at the page ii paragraph on the purpose and approach: "The identification of affected generation in a given location does not indicate that electric system reliability in that location is in jeopardy. The reported affected generation represents a seasonal peak hour condition under a fixed dispatch pattern; as such, although dual-fuel capability has been identified, iterative redispatching has not been performed to investigate the availability of gas-fired generation at other locations, or other mitigation measures ascribable to non-gas fired generation resources."

b. Maps – The color-coded maps are still a bit confusing as they leave the impression that a constrained area is the area upstream of a constraint, rather than the area downstream of a constraint.
   Response: Please see response to #1 above.
c. Affected Generation Graphs – The bar charts showing "affected MW" are misleading because they make it appear that generation that cannot be completely served is all affected. The fact that only some affected MW would not be served is explained in the text, but we question whether the visuals really provide any useful information. It would make more summarize the percentage of generation gas load that can be served with existing capacity (assuming firm load is entirely served).
   Response: Please see Section 6.1.3 for a complete description of the information presented in these figures.
d. Gas and Electric Load Assumptions – We understand the origin of the loads from the text of the report, but it would be easier to grasp the significance of the load levels if they were put in context, e.g., equivalent to an average winter or a design winter. If that's in there and we missed, our apologies.
   Response: Specifically for Con Edison, the Normal winter demand forecast was used. Exhibit 15 has been updated with a parenthetical reference.
e. Are the RCI demands in the reference case design winter/day demands or weather-normalized forecasts?
   Response: In most cases, available LDC forecasts did not reference design or normal weather conditions.
f. Was any work done to examine the degree to which redispatching the electric system would alleviate gas system constraints?
   Response: No.

5. Comments from GDF Suez:
   a. In the Target 2 Report, the Reference Gas Demand Case Sensitivity Zero, or base case, is described graphically in Table 7 on Page 34 and in narrative form on Page 35, and includes the following: "Regarding LNG import constraints, the decline in LNG imports reflects a valuation difference in the U.K., E.U. and Asia relative to the U.S., in particular New England. Destination-flexible cargoes are therefore expected to head elsewhere, not New England." We note that these "constraints" are economic, not physical. We recommend modeling actual revaporization nameplate capacity for the LNG import facilities. LNG imports can be made destination inflexible through advance contracting on a seasonal, annual, or multi-year basis. It is notable that the operating experience of this winter contrasts with that of last winter in this way - advanced contracting resulted in higher utilization of LNG infrastructure and that has had a significant positive impact on the ISO-NE system. Given the sharp contrast between winters, it is at least as reasonable to expect more advanced contracting for LNG

supply and utilization of the import terminals as it is to assume less or none in the 2018 and 2023 timeframes.

b. The Target 2 Report notes on Page iii that, "In case sensitivities, the postulated reutilization of the LNG import terminals at both Canaport and Distrigas materially lessens the amount of affected generation." It would appear that Winter 14/15 has thus far confirmed that analysis. With that in mind, we ask you to reconsider the assumptions behind the LNG Import constraints. Instead, it seems reasonable based on RGDS S16 and the actual experience of this winter where historic natural gas demand has been met in the New England region, that actual nameplate capacity for revaporization from the LNG import terminals be built into the base case model.

Response: A footnote was added in Section 2.3 to reflect the change in operating regime of the Canaport and Distrigas LNG import terminals in 2014-15 relative to 2013-14. This change may or may not be indicative of market dynamics in 2018 and/or 2023. The impact of significant regasification at Canaport in Distrigas is addressed in Sensitivity 16. It would not be feasible to revise the assumptions used in the base case model underlying the RGDS, LGDS, or HGDS.

6. Comments from EQT:

   a. As a matter of correction to the EIPC Target 2 report, the Docket No. for the West Uprate and Blacksville Compressor Station Expansion Project should be CP14-492, NOT RP14-543.

      Response: The rate filing docket number has been replaced with the certificate application docket number.

7. Comments from Williams:

   a. On page 259 in Section 8.2.1.3 Constitution Pipeline there is a sentence which states, "Because Constitution is expected to be commercialized in 2017, it is reasonable to expect..."

   b. The Constitution partners have publically stated that Constitution's expected in-serve is the second half of 2016. We recognize that an in-service date of second half 2016 or 2017 does not impact the study results since the study looks at 2018 and 2023.

   c. We would like the sentence updated to something like: "Because Constitution is expected to be commercialized in the second half of 2016, it is reasonable to expect..." or "Because Constitution is expected to be in its first full year of commercialization in 2017, it is reasonable to expect..."

   Response: A footnote has been included regarding updated information on Constitution's in service date following certification by FERC.

8. Comments from EISPC:

   a. In the Introduction and Overview of Approach Section LAI states "The GPCM analysis of constraints was performed on the peak hour of the peak day in the peak winter and summer months in 2018 and 2023." What are the assumptions

for the hour regarding gas storage levels going into and out of the peak hour? Is it assumed that there is adequate gas in storage coming into the peak hour and it can be replenished off-peak, so that the limiting factor is the withdrawal rate of the storage facility? I don't recall seeing an explanation of this.
Response: Consistent with this approach, full withdrawal capability from storage is assumed to be available during the peak hour. We assume that the gas will be withdrawn to meet demands without regard to price or the need to have storage on hand for some future period; in other words, the withdrawal capability of the facility is the limiting factor. Because the model runs only for the peak day, there are no assumptions regarding off-peak injection capability because no off-peak periods are modeled. Cycles of withdrawal and injection are not modeled in the daily model. A footnote has been added reflecting this information.

b. In Section 2.2 Key Findings of the Sensitivity Cases LAI states "The only change in the amount of affected generation is a notable increase in PJM for Winter 2018, specifically in eastern Pennsylvania and New Jersey, which are the easternmost locations with significant deliveries to non-firm generators in RGDS S0, and therefore first to be affected when west-to-east flows are instead allocated to increased firm demand." I believe this statement refers specifically to RGDS S19. Is this correct?
Response: Yes, this is correct. The text has been revised to clarify.

c. In Section 2.4 Summary of Key Market Dynamics and Risk Factors LAI states "Finally, 'renewables penetration' pertains to the relative amount of wind generation operating in each PPA, coupled with new resources in each PPA's generation queue. To the extent there are disruptions in wind output due to random days when the wind does not blow." Is this sentence missing something or perhaps should it be combined with the previous one?
Response: The referenced sentence was incomplete. This has been corrected in the report to add ", the PPA would be expected to rely more on gas-fired generation."

d. In Section 3.1.3.2 Energy Profiles for Renewable Resources LAI states "…NREL data cover three years, 2004 through 2006. The average of these three years was used to develop the wind shapes." Does this tend to flatten out the wind shapes (higher valleys and lower peaks)? If so, what effect does this have on natural gas-fired generation?
Response: No. For most of the areas, a shape-stretching procedure was used to restore some of the peak and trough amplitude that was removed by averaging to produce synthetic hourly shapes.

e. In Section 4.4 HGDS RCI Demand LAI states "Where an LDC forecast was available, but did not contain a lower load growth case, the ratio between the relevant AEO2013 growth rates for the RDGS and HGDS was applied to the provided growth rate in order to calculate a scaled higher demand." Wouldn't it be a higher load growth?

Response: The sentence has been corrected to replace "lower load growth case" with "higher load growth case."

f. In Section 5.1 Background on Shale Gas Production and Market Dynamics LAI states "The most recent EIA data shows Marcellus and Utica production continuing to grow while production from the Fayetteville and Woodford plays remained flat." Verb tense is inconsistent, which makes this confusing. If you are talking about historical information, I suggest changing this to past tense.

Response: The sentence has been corrected to read "plays remain flat".

g. In Section 7.2.3 Peak Hour Affected Generation in S5a, S5b, S5c and S9 LAI states "S5b was not run for 2018 because new HVDC transmission lines from Quebec were assumed to not be operational by then." It might be helpful to mention this in the discussion of Figures 146 and 147 as well.

Response: A footnote has been added after the first sentence in section 7.2.2.

h. Regarding Section 8.1 Potential Mitigation Measures, in some cases, it may be more economical to re-dispatch to non-gas-fired (and non-dual-fueled) idle generators rather than to mitigate. That is, the incremental cost of using an idle or under-utilized generator could be smaller than the cost of mitigating the constraint.

Response: A footnote has been added in Section 8.1 to clarify the nature of this study's limitation. Please see the response to 4a.

i. In Section 8.2.1.15 Tennessee Z5 NY LAI states "Tennessee's Northeast Energy Direct Project, discussed in Section 8.2.1.14 above, would also alleviate this constraint." Previously, this was referred to as being Kinder Morgan's project. Are the two companies related or is one of these wrong? If they are related, it may be worth stating this for those of us that don't have a strong gas background.

Response: Tennessee's Northeast Energy Direct Project is a Kinder Morgan sponsored venture. References to the project now describe it consistently as a Tennessee project, with a footnote after the first reference specifying that Tennessee is a Kinder Morgan pipeline.

9. Comments from NGSA

a. Section "6.2 RGDS S0 and S1 Analysis," p. 114, first paragraph, mentions that "natural gas prices are highly volatile throughout the winter season, particularly during cold snaps,...."
We would not characterize natural gas prices as "highly volatile." We would recommend rewriting the sentence as "Unlike oil and coal, natural gas prices can increase during peak times during the winter season reflecting regional constraints particularly during cold snaps when RCI and electric sector gas demands are high."

The higher natural gas prices in the winter are typically only in the Northeast and are "cash" or "spot" prices. The daily spot market prices represent only a portion of the overall volumes of natural gas being bought and/or sold in the market. Customers who do not mitigate their exposure through available strategies in advance such as long- and short-term contracts and/or use of available financial hedging tools expose themselves to spot market prices. In New England, the daily spot/cash prices in the winter increase more than other regions because of a lack of available pipeline capacity compared to other regions.

Response: In LAI's view, across a portion of the Study Region delivered natural gas spot prices on the Winter Peak Day as well as during the peak heating season are highly volatile. The actions taken by those LDCs and gas-fired generators to manage their respective exposure are not part of the Target 2 research objectives. Also see the response to 5 above.

b. In section "2.4 Summary of Key Market Dynamics and Risk Factors," page 35, the discussion "Regarding LNG import constraints"
The LAI Reference Gas Demand Scenario Sensitivity 0 (RGDS S0) or base case, assumes LNG import constraints in ISO-NE asserting that "destination flexible" cargoes will go to Asian or European markets rather than the Northeast US. We do not view this as a valid assumption. These are not operational constraints; they are economic market decisions on whether to fill the tanks. Given the operating characteristics of the system this winter, economic market decisions do and can change rapidly as in the case between Winter 13/14 and Winter 14/15. For this reason, I would recommend adding a sentence that mentions that economic market decisions for LNG imports can change and would not make the assumption of where cargoes may or may not go under this particular "Market Dynamics" discussion. In fact, I would change the heading from "Regarding LNG import constraints" to "Market Contracting Decisions to Rely on LNG Imports."

Response: The decision to assume no regasification of LNG at the Repsol Canaport and Suez Distrigas import facilities, excluding send-out to New Mystic 8&9, was based on Target 2 study goals and information available to LAI and the PPAs in 1H-2014. Assessment of stakeholder contracting decisions to rely on LNG imports was not part of the Target 2 study design or research objectives. The impact of regasifying LNG for north-to-south flow on M&N from Canaport as well as back-end injections into the Tennessee and Algonquin mainlines is addressed in Sensitivity 16.

c. 3. Section "6.1 Analysis Methods," p. 102, bottom of second paragraph, discusses the slack deliverability in and around Boston due to the decline of LNG sendout from Suez Distrigas LNG facility during the peak day of January 3, 2014.

A decline in sendout does not translate into an inability for LNG sendout in future years based on market decisions. Consistent with the above description, while the Northeast market had not made a significant investment in LNG supply volume contracts in previous years, we've seen more contracting this year and therefore, one cannot make an assumption that prior year contracting practices will be static for each year going forward. I would recommend mentioning that it was not due to an operational constraint but due to economic market decisions on whether to fill the tanks and those decisions can change depending on various market factors. In fact, we understand that some volumes of LNG from Distrigas were sent on Algonquin on 1/3/14 and assisted in meeting peak day demand in New England.

Response: See response (b) above.

d. In Section "6.2.1.111 New Brunswick Supply/Nova Scotia Offshore Supply," on p. 134 and again in section 6.2.3.11, p. 159, it is stated that "we have assumed that the Canaport LNG import facility will not regasify LNG for sendout for M&N due to supply chain uncertainty affecting destination-flexible cargoes.... Even though there is slack deliverability to M&N, insufficient gas production from Atlantic Canada...coupled with the loss of Canaport vaporization potentially affects generators directly connected to M&N and ...generators located behind LDCs..."
LAI included a RGDS S16 (Reference Gas Demand Scenario Sensitivity 16) which contemplated additional sendout at Canaport and Distrigas and they note on page iii of the draft report that, "In case sensitivities, the postulated reutilization of the LNG import terminals at both Canaport and Distrigas materially lessens the amount of affected generation." (emphasis added) Perhaps we could include similar conclusions in the areas mentioned above.
Response: The impact of increased sendout from Canaport and Distrigas is noted in the executive summary and in Section 7.3.2.

e. In section "6.2.1 RGDS S0 and RGDS S1 - Winter 2018," p. 123, third paragraph, it is mentioned that while GDF Suez meets the delivery needs of the New Mystic generation station that "additional regasification quantities into the back end of the Algonquin and Tennessee mainlines are zero."
We believe that LNG import facilities should be modeled at nameplate or send-out capacity (in the same manner as with the pipelines) rather than with assumptions on market decisions that can and do change rapidly. One cannot disregard the potential send-out capacity (operational capacity) whether it is currently being utilized or not. As demonstrated by system performance this winter, the west to east constraint is mitigated with injections of LNG from the East.
A recent ICF Quick Take, entitled, "Return of the Polar Vortex - Cold Renews High Demand, but Some Markets in Better Shape "referenced a Platts Gas Daily

story from February 20, 2015, reporting, “regional gas demand in New England hit a record high of 43.1 Bcf/d on February 16, breaking last year's record of 41.9 Bcf/d on January 8, 2014."Given that LNG vaporization played a role in meeting that peak demand, its capabilities should be modeled accordingly.

Response: See response to (b).