From: Joseph, Kelli [mailto:Kelli.Joseph@nrg.com]
Sent: Friday, July 08, 2016 3:40 PM
To: 'paul.hibbard@analysisgroup.com'; 'todd.schatzki@analysisgroup.com'; 'craig.aubuchon@analysisgroup.com'; Allen, David M; Eckels, Deborah
Subject: [EXT] NRG Comments on Draft DCR Report

All –
Please see the below comments from NRG on the initial DCR Draft.
Thank you,
Kelli

NRG Comments on the Draft DCR Report

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- **NRG supports the recommendation that the F Class Frame unit, with SCR and DF capability, represent the peaking plant technology.**
  - Given current siting and permitting challenges in NY, and potential retrofit costs stemming from future regulations, it would be imprudent to build a unit without SCR in NY.
  - Without firm transportation, a peaking unit will be subject to gas procurement challenges, very likely on the same days the electric system is stressed and calling on peakers. Given pipeline siting challenges in NY and the expected increase in electric generation from gas, all gas-fired generators will be relying on the existing pipeline capacity, without the potential for additional capacity release in the secondary markets. Further, NYISO is considering market design changes that place a high value on performance during stressed system conditions. For all of these reasons, assuming a unit would build without DF capability in NY would be imprudent.

- **NRG has concerns with the net EAS revenue model proposed, and with key inputs/assumptions in the costs and revenues developed for the peaking unit.**
  - ***Concerns with costs:***
    - **Gas Pipeline Costs:**
      - While little public information is available on the costs of pipeline laterals behind an LDC, recent studies (EIPC, NYISO Levitan, etc.) point out that the costs of siting pipelines on an LDC system often include costly system upgrades. The DCR study assumes an average cost for a lateral off of an interstate pipeline, while stating that the unit would be as likely to site off of an interstate as behind an LDC. Thus, the gas pipeline costs are likely understated, given the option to site behind an LDC.

- ***Concerns with the dispatch model***:
  - The model assumes optimal dispatch and optimal market offers, set at the opportunity cost of producing energy or reserves. This approach likely *overstates* the expected EAS revenues:
    - NYS expects significant amounts of renewables in the near future. While the Clean Energy Standard is more likely to have an impact in later DCR years, NY-Sun program targets will be reached during this DCR period. This means that peakers will likely run outside of an optimal dispatch pattern, either kept on/turned off to handle intermittent resources. In addition, since the NYISO market model is not set up to optimize all emissions limitations, these units will have to manage emissions limitations via market offers. Indeed, NYISO has recognized these limitations in its market and had a market design initiative to allow for bids to better reflect potential fuel or emissions limitations. However, this market design will not be place within this reset period. Assuming perfect dispatch and perfect offers overstates revenue estimates.
  - The proposed intraday gas price in the model assumes a slight premium in RT based off of the DA gas price (10% NYCA; 10% G-J; 20% NYC; 30% LI). This method likely *overstates* gas prices on most days when there is little variation from the DA gas price to the RT gas price. More importantly, it also significantly *understates* gas prices on days when the gas system is stressed. AG should come up with a better mechanism for assessing DA/RT gas price differentials that better reflects the secondary capacity release markets. For example, an assumption that a specific number of days will result in gas price spikes during specific times of the year and/or times of day. A number of studies have been completed over the past several years (including the recent EIPC study) that highlight the likely times of gas pipeline system stress or high utilization when gas prices are likely to be high.
  - In addition, since the model assumes optimal dispatch and optimal offers, it assumes a gas peaker *without a DA schedule* can procure gas in time to either provide energy or provide reserves in RT. Especially during winter periods, this is likely a flawed assumption. It is well-known that capacity release scheduled in the Timely cycle (DA) is considered firm in RT. If a peaker without a DA schedule waits until RT to procure gas, not only could it be challenging to procure gas, there may not be an intraday cycle available at the time the gas needs to be scheduled. Even if an intraday cycle lines up with the time the peaker would be scheduled in RT, that gas could be "bumped" in favor of a shipper with a higher quality transportation contract. Regardless of the timing of the gas nomination, on peak winter days that gas will certainly cost more than the premiums assumed above.

        - Finally, Iroquois Zone 2 is the gas hub recommended for Zones F and G, rather than Tennessee Zone 6. While the consultants demonstrate that TGPZ6 and IZ2 are highly correlated, Iroquois may make the same capacity release proposal that Algonquin filed at FERC. This could mean that prices on Iroquois could be significantly depressed in the near future, and not reflective of actual gas prices in Zones F and G. For this reason, TGPZ6 is a better gas index in Zones F and G.
- **<u>NRG concerns with the Financial Parameters</u>**
    - The report points out that appropriate cost of capital and amoritization period assumptions should reflect the specific financial risks faced by the developer, given the nature of the project, its technology, *and the NY electricity market context.* While several key assumptions attempt to reflect the risks associated with project development in the NY electricity market, these assumptions do not fully capture the risk to future cash flows, and thus the financial risk of electricity project development in NY.
        - AG states that the appropriate WACC for the peaking plant should be greater than the WACC of established IPPs, and less than the WACC of a project-financed project. However, the final After Tax WACC is only slightly higher than the ATWACC assumed in previous resets, and similar to the ATWACC assumed in ISO-NE and PJM despite the report's recognition that "*relative to other RTOs, developers within the NYISO region may face greater project-specific risk.*"
        - In addition, the report concludes that the ATWACC is consistent with "fairness opinions" that evaluated the NRG/GenOn merger. There, the cost of capital for NRG ranged from 7% to 8.5% and GenOn from 8.5% to 9.5%. The report stresses that the appropriate WACC should be somewhere *between* that of an established IPP and a project-financed project, yet ultimate ATWACC is closer to an established IPP.
            - Relying on studies conducted in 2003 and 2008, the report concludes that the cost of equity for project financed projects range from 15%-20%.
            - Given the concerns raised in the report about development in the NY market, uncertainty over the exit of nuclear units, as well as the significant amount of contracted capacity likely to enter the NY market in support of the State's Clean Energy goals, the cash flow risk to project-finance projects is likely to be <u>*much*</u> <u>*higher*</u> than the 15% assumed for projects developed in 2003 or 2008.
                - The upper bound of the cost of equity should be increased, and the assumed cost of equity for the peaking plant should be increased.
                - And/or, the assumed amortization period should be shortened, given the uncertainty about the amount of capacity in the NY market (nuclear units may be kept on, and new contracted capacity may enter the market).

Power to be free

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