IRP Modeling Advisory Group

Responses to Questions Posed Following Webinar #3

12/14/2016

Background

Energy Division hosted the third Modeling Advisory Group (MAG) webinar on 11/17/2016.[1] On 11/22/2016, Energy division staff circulated an email to the service list of the IRP-LTPP proceeding that provided notice of the opportunity to pose additional follow-up questions on the content presented during the webinar. This document contains all the questions received along with answers to those questions, along with supplementary questions and answers intended to provide additional detail about the RESOLVE model.

Questions and Answers

1. What are the implications of using an annual PRM constraint rather than a monthly RA requirement? Will this lead IRP recommending over-procurement relative to RA requirements in the near-term?

   RESOLVE is a physical model of the CAISO system (and its neighboring balancing authorities); in this type of model, in which investment decisions are made on an annual basis, the PRM constraint is imposed on an annual basis (i.e. PRM is defined as 115% above annual 1-in-2 peak demand) to ensure that the physical availability of generation on the system in each year is sufficient to meet system reliability needs. In other words, the modeling conducted in the IRP is designed to identify the most cost-effective investments to make on top of an existing electric system—not to suggest how individual utilities should satisfy their monthly RA obligations. This type of long-term generation planning exercise is distinct from the shorter-term monthly contractual requirements imposed upon LSEs through the resource adequacy program. The IRP is not intended to replace the LSEs' monthly RA contracting requirements, and thus should not lead to near-term over-procurement of capacity.

[1] The presentation materials and an audio recording of the webinar are available online on the IRP Events and Materials page: http://www.cpuc.ca.gov/General.aspx?id=6442451195. More information about MAG can be found on the same page.

2. Can you talk a little more about the role of exports and potential limits on them as tool to reduce curtailment?

   In addition to incorporating zonal transmission constraints, RESOLVE utilizes an explicit assumption to limit exports from the CAISO footprint. This assumption has a direct and significant impact on the level of curtailment experienced in CAISO operations. In past studies, E3 has used a wide range of values (2,000 - 8,000 MW) for this value in recognition of the significant uncertainty in the size of potential export markets for sale of surplus California power.

3. Still not sure that I understand unit commitment in the operational model. Based on a discussion on a previous call, I understand that the operational model can commit fractional units. How are the start costs of fractional units treated? Are they estimated as fractions of the start costs of whole units? How are the Pmins and Pmaxes of fractional units treated after fractional units are committed? As fractions of the Pmins and Pmaxes of entire units?

   The operational model in RESOLVE includes a linearized version of unit commitment—in other words, the commitment variable (i.e. number of units committed) for each category of generators is continuous and can take on any value between 0 and the total number of generators in that category. Aside from this simplification, many of the details of the formulation do not differ from traditional characteristics of a mixed-integer unit commitment problem:

   - *Generation from each category must exceed the commitment variable times the Pmin of that category;*
   - *Generation from each category must not exceed the commitment variable times the Pmax of that category; and*
   - *Start costs are included based on the change in the commitment variable from one time step to the next (i.e. "number" of units started) times the unit start cost.*

   As an example, consider an example category with 4 units, each with a Pmax of 100 MW and a Pmin of 50 MW. In an interval in which 3.5 units are committed (since the commitment variable is linear, fractional units may be committed), the dispatch of these three units will be constrained between a maximum level of output of 350 MW (3.5 x 100 MW) and 175 MW (3.5 x 50 MW). Assuming a start cost of $100/MW, If the commitment variable changes to 3.75 in the next time step, a start cost of $2,500 (0.25 x 100 MW x $100/MW) will be included in the objective function.

   E3 has also added constraints that capture the minimum up and down times, as well as ramping constraints, on each category of generators.

4. Slide 13 states the local RA deficiency will be adjusted to reflect key differences in assumptions between prior TPP and current IRP.
   a. What TPP does Energy Division plan to rely on for the IRP?

      The local capacity needs constraint will be based on results from the TPP studies. However, Energy Division has not yet proposed which vintage of TPP studies will be relied upon. Any divergence of underlying physical resource assumptions and possibly *load forecast vintage between the TPP studies and the IRP RESOLVE modeling will need to be reconciled.*

b. Is there a concern that the TPP relies on a different reliability metric than the proposed metric (1-in-2 with a 15% PRM) for the IRP?

   No. It is established practice to use a 1-in-2 peak load for the system need constraint and a 1-in-10 peak load for a local area to establish the local capacity needs constraint. The system constraint is based on ensuring a minimum amount of system available capacity to meet annual 1 in 2 peak load. The local constraint is based on ensuring a minimum amount of available capacity in a specific local area to meet the local reliability requirements tested in the TPP (which include testing against 1 in 10 peak load in local areas). This is no different than what has been done historically in LTPP system studies where the resource stack included capacity that was necessary to meet local needs.

c. What assumptions does Energy Division plan on changing from the TPP for the IRP?

   As stated above, any divergence of underlying physical resource assumptions and possibly load forecast vintage between the TPP studies and the IRP RESOLVE modeling will need to be reconciled. Energy Division will work with California Energy Commission and CAISO staff and propose an approach to reflect local capacity requirements estimated in TPP studies in the IRP capacity expansion modeling (RESOLVE). One approach would be to use the Energy Commission's LCAAT tool, which projects loads and available local capacity on an annual basis. Examples of assumptions that could be changed are listed on the slide: load forecast (due to vintage differences), retirement assumptions, and transmission upgrades.

d. When Slide 13 referred to "changes in assumed retirements", what was it referring to?

   In the event that the schedule of expected future generator retirements assumed in IRP does not align with assumptions used in the TPP to derive an estimate of local capacity deficiency, an adjustment to the deficiency estimate is needed to reconcile the impact of this difference in assumptions. At a more general level, in order to incorporate the assumptions on local capacity deficiency from the CAISO's studies into IRP, CPUC will need to reconcile all the supply- and demand-side assumptions between the two efforts in order to ensure consistency of assumptions.

e. Transmission projects can often lower local RA need. What transmission projects does Energy Division plan to rely on? Will it use the most recent version of the TPP, which will be approved next year?

   As stated above, Energy Division has not yet proposed which vintage of TPP studies will be relied upon. The likely most current, public information available are the transmission projects expected to be approved in the 2016-17 TPP.

5. The recent CEC Energy and Demand Forecast states the following with respect to the impact of PV at the time of the forecast peak load: "At some point, continued growth in PV adoption will

likely reduce demand for utility-generated power at traditional peak hours to the point where the hour of peak utility demand is pushed back to later in the day. This means that future PV peak impacts could decline significantly as system performance drops in the later hours. This possibility has not been incorporated into the demand forecast through CED 2015, since staff has not yet developed models to forecast hourly loads in the long term. Staff expects to develop this capability for the 2017 Integrated Energy Policy Report (2017 IEPR), and such an adjustment to PV peak impacts could significantly affect future peak forecasts." Will this be taken into account when determining load and local RA deficiency?

At the system level, the impact of increasing penetrations of behind-the-meter PV on load shapes at a system level is accounted for directly in RESOLVE through separate representation of hourly shapes for gross load and behind-the-meter PV; as the penetration of behind-the-meter PV increases, its profile is subtracted from gross load to determine the system load shape. At a local level, this analysis will rely primarily on work already completed by CAISO and the CEC (for example TPP study results and/or the LCAAT tool), and thereby will inherit from these prior studies the conventions they used regarding the peak shift impact of behind-the-meter PV.

6. Slide 14 states that "[t]he addition of local RA constraints offer additional location-specific value for candidate resources."
    a. What information will RESOLVE produce related to locational value?

    RESOLVE includes a single constraint that requires that the amount of new capacity installed across all local areas be sufficient to meet the total projected deficiencies of all local areas. RESOLVE is not capable of providing more granular information on locational value.

    b. Can the locational information be used to target distributed generation?

    RESOLVE will select an optimal mix of new resource investments that satisfy both the system need constraint and the total deficiency across all local areas. To the extent new resource investments are selected to meet local need constraints, this information could be used to inform targeted procurement of resources in local areas with deficiencies.

    c. Can additional locational information related to air quality and disadvantaged communities also be integrated into RESOLVE to help further identify the location-specific value for candidate resources?

    RESOLVE is not capable of this type of functionality.

7. Slide 17 states that "Spinning & non-spinning reserves not currently modeled." How does RESOLVE propose accounting for the GHGs related to spinning reserves? How does RESOLVE propose to minimize GHGs and optimize low and zero carbon integration options consistent with the requirements of SB 350 if spinning & non-spinning reserves are not currently modeled?

E3 is currently working to implement a spinning reserve constraint on the dispatch model in RESOLVE. That said, the inclusion or exclusion of this constraint from the model is not expected to be consequential for the quantification of greenhouse gas emissions.

8. Slide 21 refers to forecast error. What data does RESOLVE plan to rely on for wind and solar forecast errors?

   E3 has used forecast errors developed by the National Renewable Energy Laboratory (NREL) for wind and solar generation. These forecast error assumptions were provided to E3 based on data developed in NREL's WIND and SIND Toolkits.

9. Slide 22 states that "RESOLVE assumes that flexibility reserve requirements can be met by a variety of resources."
   a. Is demand response assumed to meet flexibility reserve requirements?

      No.

   b. Is increased coordination between other balancing authorities assumed to meet some of the flexibility reserve requirements?

      No.

10. Slides 10-12 discuss ELCC. How does the ELCC surface for renewables described on Slides 10-12 (which reduces the ELCC for instance for solar, as solar penetration increases), account for the potential for significantly increasing energy storage? Does the surface integrate consideration of major zero carbon solutions for grid balancing, namely energy storage solutions including battery EVs, and other options? Does this surface account for the combined value of solar + wind + storage, which together could approximate a more steady-state resource? How are variations related to location and type of resource taken into account?

    RESOLVE evaluates the decision to build (or not to build) storage independently from renewable generation; candidate storage resources are attributed capacity value commensurate with their ability to sustain capacity output across a duration of four hours. The value of this capacity to the system (or local areas) is attributed to the storage resource—not to the renewable generation that might be collocated with it—and as such, does not directly impact the ELCCs that one would assign to solar and wind resources. Other factors that might impact the future load shape (e.g. electric vehicles, energy efficiency) are not directly captured in the ELCC surface, which requires a fixed load shape as an input to generate and consequently does not adjust with changes to the demand-side portfolio.

11. Load following is calculated exogenous to RESOLVE, and you developed two flavors – one for high solar and one for low solar (for example) and there is some interpolation between these two. How does RESOLVE know which set of LF requirements to apply as a constraint since the optimal portfolio has not been determined by RESOLVE yet?

    Load following requirements are an exogenous input to RESOLVE. E3 has calculated load following requirements consistent with two 50% RPS portfolios—a high solar and a diverse portfolio—and the user must specify which of these requirements to include in the model. In this respect, the model does not currently capture the impact of changing load following needs in the optimization of the portfolio, as this is inherently a very non-linear relationship. This means that *for each case setup for RESOLVE, the user must specify which of the two hourly load following requirements shall be used by RESOLVE as an operational constraint.*

12. How are hourly regulation requirements set for RESOLVE? Slide 22 talked about which resources can provide load following. Which resources can provide regulation? Can renewables provide down regulation?

    RESOLVE imposes regulation up and down requirements equal to 1% of hourly load on the operations of the fleet. Regulation requirements must be met by a combination of gas, hydro, and storage resources. Renewables cannot provide regulation down.

13. The last slide on frequency response constraint (MAG 3 Presentation) seems to have an element in conflict with the May 2016 LTPP A&S Ruling: the Ruling says that pumped hydro capacity will not count towards meeting the frequency response requirement, whereas this slide indicates that hydro and pumped storage are assumed to meet half of the requirement.

    While the language between these two references is indeed inconsistent, the two documents do suggest consistent treatment of the frequency response constraint in modeling. Both documents indicate that half of the frequency response need can be assumed to be met by resources other than storage and thermal generation (in the MAG 3 presentation, these resources are assumed to include pumped hydro, whereas in the LTPP A&S ruling, pumped hydro is not included), but this half of the requirement is not modeled explicitly, and as a result, whether or not pumped storage is included is inconsequential from a modeling perspective. More important from a modeling perspective is how the remaining half of the frequency response need must be met; here, both documents indicate that the remaining half of the frequency response need must be provided by a combination of storage and thermal resources.