RAAC Technical Committee Meeting
November 20, 2013

Status of Data Required for the 2019 Adequacy Assessment

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1. Hourly loads (including energy efficiency) - Lead: Massoud Jourabchi (Council)
Hourly loads used in GENESYS for adequacy assessments are produced using the Council's econometric short-term model. For long-term studies, such as those used to develop the Council's power plan, the Council's long-term load forecasting model is used. Unlike the short-term model, which uses historical loads to project trends, the long-term model is an end-use model driven by population, economic environment, employment and other factors. Unfortunately, the long-term model does not produce hourly loads needed for an adequacy assessment. It forecasts monthly average and monthly peak hour loads for a 20-year span.

A comparison of load forecasts between these two models shows a close alignment for monthly average loads in the early years (1 to 5), with some diversion in the later years. Peak load forecasts are not as close, even in the early years. These results are not unexpected and can be explained by differences in forecasting methodologies between the models. The short-term model can be "calibrated" to the long-term model forecast to provide some consistency. However, it is not obvious that the long-term model's forecast for the early years is better than the short-term's forecast. Thus, for our adequacy assessments, the non-calibrated short-term forecasts are used.

Up to now we have been discussing aggregate regional loads. To split regional loads into the new 3-node configuration (west, east and southern Idaho), we begin by performing an econometric forecast just for southern Idaho. The southern Idaho loads are subtracted from the regional loads to yield an aggregate east-west load. A west load factor and an east load factor are applied to the aggregate east-west load to yield hourly loads for the west and east nodes, respectively. This method is obviously an approximation, which results in the east and west nodes having identical hourly load shapes. This is not ideal but is not a bad approximation given the amount of work required to perform econometric load forecasts for both the east and west nodes. Because most of the region's load is in the west (about 60%) and because Idaho's loads shape has been subtracted out of the regional aggregate, the resulting load shape is closer to the expected load shape for the west than for the east. Because most of the hydro generation is produced in the east (and the loads are smaller than the west), it is not as important, from an adequacy perspective, to get the east shape perfectly correct. We intend to compare our forecasted loads to observed loads to determine how good or bad this approximation is.

2. Energy Efficiency - Lead: Massoud Jourabchi (Council)
Our load forecasts include effects of energy efficiency. Because observed loads, used to drive the short-term model, include the effects of energy efficiency, it will project trends for future savings. Unfortunately, those projections are aggregated with projections for load growth. To extract the amount of trending conservation, a separate econometric analysis is performed just on the observed energy savings over the past several years. The forecasted savings can be subtracted (i.e. magnitude added to the load) from the load forecasts. We can then add in the Council's 6th plan conservation targets (i.e. subtract the targets from the load) to get a final load forecast, net of energy efficiency effects. It turns out that the trending conservation savings are not much different from the 6th plan targets, thus it has been recommend that we simply use the trend values rather than the target values.

To get the split of energy efficiency savings among the three nodes, an assumption was made that savings are directly proportional to the magnitude of load in each node. This approximation can be improved for future assessments.

Existing demand response or solar generation is treated in a similar fashion. If a DR program or solar generator has been in use and has affected observed loads, an assumption is made that the short-term model will pick up their effect on future loads. New DR or solar must be included separately, either exogenously by subtracting estimated amounts from the load or explicitly by simulating their operation within the model. Currently, these resources are treated exogenously in a post processing program. (See the section on demand response.)

Another issue of concern is the hourly shape of energy efficiency. Unfortunately our end use data for conservation is not as good or complete as we would like. Therefore, the assumption made for adequacy assessments is that all energy efficiency savings will have the same hourly shape as the hourly load forecast. This also can be improved upon for future analyses once we have better end use data.

3. Contracts - Lead: Pat Byrne (BPA)
Genesys only models firm contracts that either come into a Northwest node or leave the node. Within-node contracts are not considered and will not affect the regional adequacy assessment. Contract data is derived from the BPA White Book publication. Contracts are implemented by subtracting or adding their hourly magnitudes from or to the nodal hourly loads. In times of stress, it may be possible to curtail outgoing contracts but this option is not currently modeled in GENESYS. Firm outgoing contracts are treated just as firm nodal load. The Canadian Entitlement Return (CER) is assumed to be delivered and is, therefore, modeled as a firm contract.

4. Hydro data – Lead: Kim Fodrea (BPA)
Hydroelectric system data comes from BPA hydro regulations. The latest hydroregulation data, obtained in late summer 2013, is based on the 2015 BPA rate case. It contains an 80-water year input record and reflects the latest biological opinion constraints for fish and wildlife. GENESYS includes the entire HYDSIM model used by BPA to develop hydroregulation studies. The difference is that GENESYS performs a Monte-Carlo hourly simulation that dispatches hydro and thermal resources dynamically based on operating cost. GENESYS first assesses the amount of energy that can be derived from the hydro system when drafting from start of month elevations to flood control elevations, to refill elevations, to drafting rights elevations and to empty (without violating other constrains). These "blocks" of hydro energy are then priced relative to certain reference thermal resources, with higher elevation hydro being less costly than lower elevation hydro. The model builds a resource stack, with cheapest resources on the bottom, interspersing the hydro blocks wherever they fit pricewise. Sufficient resources are taken from the stack to meet the monthly average load. All of the dispatched hydro blocks are then aggregated to get the total monthly average hydro energy dispatch.

The model then drops into the hourly dispatch, which uses hydro shaping limits to dispatch hydro generation over the hours of the month (see the "Peak vs. Energy curves" section below). During this phase of the dispatch, the hydro system is allowed to draft below the drafting rights elevations but only for short periods of time and only if no other resource is available (i.e. curtailment would result if this wasn't done). As soon as the system recovers, this "borrowed" hydro is paid back by running thermal resources more or by making market purchases.

5. Peak vs. Energy curves – Lead: John Fazio (Council)
For regional studies, the Council's Trapezoidal Model is used to create peak vs. energy curves that tell GENESYS how monthly hydro energy can be shaped into each hour of the week and month. The curves used for last year's assessment were based on the 70-year hydro record and were developed for a 2-node Northwest configuration. Work is underway to update these curves to the new 80-year water record and to accommodate either a 2-node or 3-node Northwest topology.

It was decided that for future adequacy assessments, a 3-node Northwest topography, matching that in the AURORA model, should be used. This involves shifting some hydro project generation into different nodes. It became apparent that by doing that and also by splitting off southern Idaho, the correlation between nodal hydro peaking capability and regional hydro energy was lost for the west and southern Idaho nodes. The suggestion was to change the relationship to make the nodal peaking capability a function of the monthly average nodal hydro energy (and not the regional hydro energy). This work is not yet complete.

There is also a concern about the precision of this particular method. The model performs a monthly dispatch simulating the operation of individual hydro projects. However, for the hourly dispatch, hydro is treated in aggregate for each node. This is done to save run time and also because no project-specific hourly hydro model is available to easily integrate into GENESYS. The peak vs. energy curves are piece-wise linear curves built up from a set of 80 points (one for each water condition). These curves contain four linear segments, represented by straight line connections between five points. The low and high points represent the peaking capability for the lowest and highest energy years, respectively. The three intermediate points are derived by taking the average value of the three middle quintiles of data. The concern is that in some cases, the peaking capability may be under or over stated. The hope is that some testing can be devised that will more quantitatively assess the precision of this method. If this method proves to not be precise enough, efforts will be made to either improve the approximation or to acquire a project-specific hourly hydro model.

6. INC/DEC and associated files – Lead: Patricia Byrne (BPA)
Reserves are required for a number of reasons, such as load following, contingency operations and also to provide within hour balancing for variable generating resources (namely wind). Wind reserves are typically referred to as incremental (INC) or decremental (DEC). INC reserves represent generation that is ready to be dispatched should wind generation suddenly drop off. DEC reserves represent generation that can be turned off should minimum generation exceed loads. For modeling purposes, all INC and DEC reserves for wind are provided by the hydro system. INC reserves are combined with hydro maintenance data in the HYAVAIL file. The INC reserves are subtracted from the hourly hydro peaking capability. DEC reserves are built into the Trapezoidal Model as minimum turbine flows at certain federal projects. The effect of this is to increase hydro minimum generation (and also slightly reduce maximum hydro generation).

The amounts of INC and DEC reserves used for last year's assessment (900 MW for INC and 1100 MW for DEC) originated from BPA and represent the maximum amount the federal hydro system is willing to provide. It's not clear whether more balancing reserves can be provided by the federal hydro system or by non-federal hydro and what ramifications that might have with respect to meeting fish and wildlife hydro operations and cost.

A second question that arises is where additional INC and DEC reserves will come from as the region's wind fleet continues to grow. Are individual utilities providing their own reserves? If so, how are they accounted for? Would an energy imbalance market help this situation?

7. BPA wind data - Lead: Ben Kujala (Council)
Installed wind capacity for the BPA balancing authority is provided by BPA staff. Generation data for that wind fleet is synthetically generated using historical data, which is correlated to temperature. Ben Kujala (Council staff formerly with BPA) developed the methodology to create the synthetic wind data set. The data provides 20 different wind profiles (each profile is 8,760 hours of wind capacity factors) for each historic temperature year (from 1929 through 2005). For each game of the Monte Carlo analysis, GENESYS selects a temperature year at random from the 1929-2005 range and then selects one of the 20 wind profiles available for that specific temperature year. Hourly wind generation is obtained by taking the total installed nameplate capacity of wind and multiplying it by the hourly capacity factor from the wind profile selected. That generation is then subtracted directly from the hourly load forecast.

8. Non-BPA wind data - Lead: John Fazio (Council)
We have no information regarding non-BPA wind other than nameplate capacity and location. For last year's assessment, total regional installed (and sited and licensed) wind nameplate capacity was derived from the Council's Project Database. Since we had little or no information regarding the performance of non-BPA wind, we simply assumed that all wind was in the BPA balancing authority and that it would all behave like BPA-sited wind.

The calculated hourly wind generation is subtracted from the total nodal load prior to that load being split into the nodal portions. This is not the best way to model wind. At the very least, wind for each node should be subtracted for that node's load. Secondly, it would be better to use a wind generation forecast for the dispatch algorithms to set up the initial hydro shaping. Then as the model steps through the hour by hour dispatch, the observed (synthetic wind data) generation comes into play and any differences between the forecasted wind and observed wind would result in adjustments in the hydro/thermal dispatch.

There is also quite a bit of non-NW wind in the NW that is used to serve non-NW load. For last year's assessment, we ignored this wind even though there could be times when some of that wind might be available (mostly in winter) as a potential market supply. We will investigate this further for the 2019 assessment.

9. Transmission – Lead: John Fazio (Council)
Transmission topography in GENESYS will be designed to match (as much as possible) the topology in the AURORAxmp model. Transmission capacities for all nodes will be extracted from the AURORAxmp data. Also, the east/west intertie nomogram needs to be reviewed.

10. Generating resources – Lead: Gillian Charles (Council)
The Council's Project Database includes all resources simulated in Genesys except for energy efficiency and demand response. While wind project data is in this database, it is treated differently (see above) from thermal resources. The steering committee assumption is that only resources that are at least sited and licensed (including wind) should be used for adequacy assessments. A question was raised last year as to whether we should be using RPS amounts for wind instead of sited and licensed amounts. The technical committee can identify how those amounts of installed wind differ but the steering committee should make a recommendation on that issue. Using sited and licensed wind is consistent with the assumptions about other resources but is not consistent with assumptions about EE, where the Council target values are used (although a proposal has been made to change this to "trending" EE).

11. Market availability – Lead: John Fazio (Council)
CEC has provided information to Council staff on OTC retirements and expected replacements and on anticipated RPS resources for California. It is now known that the SONGS-2 nuclear plan is going to officially retire, so it is possible that some OTC retirements may be deferred. However, it is not clear to the Council staff how these changes in southern California may affect SW market availability. The technical committee will work with California entities to acquire the latest projections for OTC retirements, replacements and for RPS targets.

The Council would like to develop a framework for assessing California market supplies on an annual basis. This will involve coordinating efforts with several California entities. The end product would be an estimate of the range of possible market conditions for winter and summer. This information will then be forwarded to the steering committee, which will make a recommendation to the Council regarding how much SW market availability should be assumed for the adequacy reference case.

BPA is also investigating other potential markets, such as in Canada. Within region market availability (namely the IPPs) also need to be updated (should be available in the Council's Project Database). A new issue is whether southern Idaho will have access to a market east or south (i.e. not California or Canada).

12. Demand Response and distributed generation – Ben Kujala (Council)
If DR programs have already been implemented and are included in observed hourly loads, then their impact will be reflected in the short-term model load forecast (see above). For DR programs that have not yet been implemented, we do need to account for them. One way is to treat them as dispatchable resources. In that case we would need to know the amount, the ramp rates (if any) and when they would be used. This would require a modeling change to GENESYS.

Another approach would be to assess the impact of DR through the use of a post processing program that reads the Genesys curtailment file and applies the effects of DR and recalculates adequacy measures. This implies that DR measures would be used as a last resort, even after "emergency" hydro drafts are made. A test program has been written to make these calculations and it has distributed it to several members for review. The current concern is that the curtailment record may still include some questionable curtailments. For example, some curtailments occur over the last two hours of the day (10pm to 12am), which are likely the effect of the method used to shape hydro. These cases should reflect a condition where the daily hydro energy is probably not quite sufficient to make it through the entire day. The hydro dispatch logic in GENESYS is being reviewing in an attempt to correct these potential problems (or at least to isolate them so they don't skew the results).

13. Standby resources – Rob Diffely (BPA)
Standby resources are demand-side actions and small generating machines that are not explicitly modeled in the adequacy analysis. They are mainly composed of demand response measures, load curtailment agreements and small thermal resources.

Demand response measures, are expected to be used every year to help lower demand during peak hours of the day. These resources only have a capacity component and are not intended to provide extended energy relief. To the extent that these measures have been implemented, their contribution is already reflected in the Council's load forecast. New demand response measures that have no operating history and are therefore not accounted for in the load forecast are classified as part of the set of standby resources.

Load curtailment actions and small generating resources that are contractually available to utilities help reduce peak hour load and may also provide some energy assistance. However, they are not intended to be used often. The energy and capacity capabilities of these non-modeled resources are aggregated along with the demand response measures mentioned above to define the total capability of standby resources. A post-processing algorithm uses these capabilities to adjust the simulated curtailment record and calculate the final LOLP.

Currently, the aggregate energy capability of standby resources, as we have defined them, is 83,000 megawatt-hours. The peaking capability of these resources varies by season, with a 660 megawatt capacity in winter and a 720 megawatt capacity in summer.