DEMAND ANALYSIS WORKING GROUP (DAWG)
Demand Forecasting Pup

Notes

March 17, 2017

California Energy Commission
1916 Ninth St. 2nd Floor Conference Room
Sacramento, CA 95814

Meeting Link:
http://demandanalysisworkinggroup.org/?post_type=ai1ec_event&p=2700&preview=true

AGENDA

10:00	Welcome and Introductions – Chris Ann Dickerson, DAWG
10:15	Updates on Ongoing Proceedings – Kavalec, CEC
10:30	Forecasting Hourly Loads –Vaid Latest Findings on Peak Shift – Schiermeyer/Matsuoka, SDG&E
11:30	PV and Storage Modeling – Gautam/Dorai, CEC
12:00	Lunch (on your own)
1:00	Rate Scenarios for 2017 IEPR Forecast/Residential TOU Analysis – Marshall, CEC
2:00	Suggestions for Improved Weather Normalization Analysis – Sheng, SCE
2:30	Transportation Electrification – Weng-Gutierrez/Bahreinian, CEC
3:00	Next Steps/Adjourn

10:15 Updates on Ongoing Proceedings – Kavalec, CEC

Energy Commission held a workshop on Forms & Instructions utilities use to submit their demand forecasts. The workshop was on October 13, 2016. http://www.energy.ca.gov/2017_energypolicy/documents/ - 10132016.

The Forms & Instructions are due from utilities in April, 2017.

We will have a couple of DAWG meetings in the next several months to review information and methodologies for the 2017 Integrated Energy Policy Report (IEPR) - California Energy Demand (CED) forecast. Those meetings have yet to be scheduled.

There will be an IEPR Workshop August 3, 2017 to review the draft forecast.

Four relevant studies are underway at CEC:

- The Commercial End Use Saturation Study (CEUS)
- Residential Appliance Saturation Study (RASS) just started
- Load shape generator tool that will produce loadshapes by building type and end use. It will also produce load shapes for demand modifiers, for example Additional Achievable Energy Efficiency (AAEE) as well as hourly generation from solar/PV. This can probably be used to take place of HELM peak model.
- Lawrence Berkeley and Idaho National Labs are working on a forecast tool for an 8760 load for EVs for the number of EVs and the amount of energy used in a given year.

Kavalec/Giyenko
There was a SB 350 workshop on January 23, 2017.
http://www.energy.ca.gov/2017_energypolicy/documents/#01232017 CEC staff is considering how the energy efficiency targets will be created. There will be subtargets for utility programs, codes & standards and "remaining" category. There are 11 "buckets" identified in SB 350. NCPPA wants to help the state estimate what POUs can do to assist with developing the targets. The scoping document indicates that even with aggressive efficiency there will be a "gap" – current estimates indicate that even aggressive programs, codes & standards will not achieve the "doubling of AAEE." Chris Kavalec is developing the utility program sub targets. The CEC Efficiency Department is looking at codes & standards + the "additional" category (the "gap"). There will be a workshop later Spring 2017 to present that information. Subsequently there will be a paper proposing the targets and then a final workshop, with a final document due in November 2017. The CPUC energy efficiency goals will not be completed until September 2017 so those IOU goals will not be in the IEPR forecast.

Question: What data regarding energy efficiency forecasts will the utilities use in their forecasts?

- SDGE will use whatever is the latest information.
- LADWP – will use the goals set by the LADWP board, not SB350.
- SMUD DER group produced a forecast in summer 2016 – they expect efficiency at the level of 1.5-2% of annual sales. This is based on information regarding efficiency impacts by program and end use modeling of expected impact from codes & standards. They have annual forecasts, at this time they do not have the same type of information going out into the future for purposes such as SB 350. On the other hand, they have always had aggressive programs – 1.5 or 2 percent of load. That is the current forecast for next year. SMUD does not design/fund programs as “rolling portfolios” like the IOUs.
- SCE uses econometric modeling so they are identifying significant differences in the level of planned efficiency and adjusting the forecast when the efficiency will be different than historical levels (higher or lower – two SD from the mean) and they are using the same concept for SB 350.
- Jonathan Changus, NCPPA - most POUs are adopting targets are not a doubling. It is trying to capture as the state moves toward doubling. Navigant just produced an EE potential study for POUs. NCPPA would like to work with Energy Commission regarding developing POU targets.
- PG&E has done some modeling of the doubling for SB 30.

SDG&E has studied the impacts of cannabis cultivation. Anecdotally growing is crashing the grid in Oregon. SDG&E has made estimates; SCE is planning to do so; POUs are looking at but note the uncertainty in state and federal policy.

LADWP Cockayne recommends against developing a new load category for cannabis cultivation – it could be included in the agricultural sector (or a different existing sector). The state’s experience with server farms several years ago is an example. Server farms were expected to have huge impacts but it turned out more or less to replace other types of load e.g., in office buildings or other commercial buildings.

SCE / Energy Commission

If the IOU “rolling portfolio” implementation covers 80 percent of the anticipated programs, that moves the “rolling” 80% into the “committed efficiency category” as defined for Energy Efficiency forecasts. Traditionally the programs were funded for a couple of years and “committed” efficiency was included in the IEPR forecast: impacts from “designed and funded efficiency” (both programs and codes & standards) are considered in the CED forecast. Efficiency impacts that are likely to occur given that programs and codes & standards are likely to continue (more programs/C&S ratchets every few years) have been identified as Additional Achievable Energy Efficiency (AAEE). The analytics will therefore be different in this cycle – efficiency impacts that used to be in AAEE will now be committed. Needs discussion. At a minimum note in the forecast document that there is a change in analytics in this IEPR forecast so direct comparison of AAEE in prior IEPR forecasts will not be apples to apples. Mike Jaske is working on developing AAEE for the 2017 IEPR forecasts and will be producing information on AAEE in March/April 2017.

10:30 Forecasting Hourly Loads – Vaid, CEC

The objective of the modeling is to:

- Develop a model to forecast long-term hourly electricity loads (developed using R software).
- Model will allow us to investigate topics such as peak shift due to PV, monthly demand, DR integration, AAEE etc.
- Currently have hourly EMS data from 2006 on for the three IOUs in California. Namely, PGE, SCE, SDGE.

Energy Commission staff are developing ideas from the half hourly model developed by Shu Fan and Rob Hyndman from the Monash University.

- Multiple regression model with correlated errors.
- Each hour is modeled separately. Splines in order to improve prediction.

A bootstrapping approach was used to simulate results and then sample from a number of simulations. This model was developed using 100 different values for 10 years of data, and then extracting 1 in 2 year and 1 in 10 probabilities. For each month there are 15 years of historic data. These data are characterized as monthly blocks (e.g., 28, 30 or 31 days as appropriate) to build the future forecast period. This retains some calendar effects. One suggestion from the group is to consider smaller blocks, e.g., weeks.

Note that there are some difference in the CAISO data and the QFER data used for Energy Commission forecasts. Staff are working on getting hourly demand response data from CAISO but that transaction is still in process.

Kavalec
Peak forecasts are calibrated using weather normalized for the most recent year. In this research, staff are comparing that traditional approach with this new hourly model.

Latest Findings on Peak Shift – Schiermeyer/Matsuoka, SDG&E

SDG&E has a sample of 500 residential customers with smart meters. They compare all hourly shapes to estimate load w/o solar. If you add solar generation the SDG&E grid could show a 10am peak using estimated generation on that outlier day day. Most of the time the peaks are shifting about an hour.

On about 1/3 days of the year there is a peak shift. By 2018 the peak is in HE 19. Peak cannot move much later with PV, since the sun goes down then. However, once significant storage and/or EVs are on the grid this can change.

No one really knows how interactions between solar/PV, TOU rates andbehind the meter (BTM) storage will affect load. SDG&E does have an EV TOU rate – approximately 12am – 3am.

11:30 PV and Storage Modeling – Gautam/Dorai, CEC

PV/Net Energy Metering (NEM)

New NEM rates/reimbursements are being enacted "NEM 2.0.

- Full retail credit but need to be on a TOU schedule
- NBC charged on actual delivery from utility
- No limit on system size
- Exempt from standby charges
- Small interconnection charge but systems 1 MW+ may have to pay for upgrades
- No fixed/demand charges for residential customers unless rate reform proceeding sets such charges

Adoption projections are based on payback.

Solar City
There has been a dropoff in sales last year because NEM 2.0 is more complicated to understand and less attractive to customers

SCE had been seeing more than 50% growth of solar/PVeach year. Last year, 2016, the adoptions decreased slightly. The new TOU rates will reduce the amount of growth. Adoption based on a payback threshold and new rates will presumably further reduce adoption rates.

Assumptions for the 2017 IEPR forecast will include low- medium- and high- scenarios and will address peak shift, and several TOU rates. Staff are considering options regarding retail crediting, flat charge (same as 2015 IEPR) and wholesale compensation.

Disaggregating forecasts to provide more local results
(This issue applies throughout the forecast though the discussion arose in the context of solar/PV.) Incorporating locational effects would be nice but would be extremely difficult given the multiple layouts of CEC forecast zones and available data. The topology doesn't line up – there are CEC forecast zones (based on CAISO transmission zones). A different schematic is used CEC climate zones - used to forecast energy efficiency impacts from codes & standards and programs and produce AAEE.

Energy Commission staff created a new forecast zone schematic for the 2015 IEPR, with more zones than prior versions. In other words, more zones means that at least some zones can cover smaller geographic areas than before. All stakeholders – Energy Commission, CPUC, CAISO, utilities, service providers, etc. in the state are interested in having increasingly disaggregated forecasts to inform local planning. However, the forecast results lose fidelity when divided in to smaller and smaller geographic areas. Forecast inputs are developed using data based on larger areas (e.g., econ/demo for major population areas; service-territory level / transmission zone level historical sales, weather stations, etc.). Currently the Energy Commission forecasts are at best limited by county: consumption data is by county, the lowest level of disaggregated econ/demo data from Moody's is by county (although that is probably a stretch because those data are still derived from samples of larger areas).

The "law of large numbers" generally works to improve forecast accuracy. More building, etc. leading to more energy use in one part of the forecast zone tends to be offset by less building, and less energy use somewhere else. Disaggregating the CED forecast, for example, to the geographic area served by a single substation could yield wildly inaccurate if, for example, a single housing development or new commercial building entered that circuit over the course of a year or two.

Energy Commission staff have been reluctant to introduce additional disaggregation since the disaggregated results have greater uncertainty. Stakeholders that in theory desire additional disaggregation share these concerns. Energy Commission staff are considering options for further disaggregation with a manageable degree of uncertainty. It may be possible to produce further disaggregated results with post-processing that incorporates local information. This would be resource-intensive and require substantial additional staff hours. This is an ongoing discussion.

Behind the Meter (BTM) Storage

Goals of staff analysis are:

- Understand interplay between climate, building type, business operations, fuel mix and end uses in site selection for a specific battery technology
- Identify application suitable for a specific business, utility tariff
- Model stand alone and paired storage dispatch scenarios
- Evaluate economic case using System Advisor Model (SAM), Energy Storage Valuation Tool (ESVT)
- Extend analysis ➔ Analytic Framework

Right now BTM is a small driver of reduced load but developing the framework is important policy drivers e.g., AB 2868 that will increase uptake of DER including storage.
https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160AB2868 Since storage is such a small part of load right now, it's likely that this framework won't be used in the IEPR forecast until 2019.

The approach considers benefit/cost analysis, storage solution design and site/segment load analysis using a variety of available data sources. A test case for Lodging has been completed.

Access to additional data, including 15-minute AMI data, etc. would be helpful in improving this model It would be great if any DAWG members who have access or suggestions to data that may be helpful in this analysis contact Troy.

Next steps include expanding the analysis to include additional segments/sectors, technologies, rates, new data, etc.

1:00 Rate Scenarios for 2017 IEPR Forecast/Residential TOU Analysis – Marshall, CEC

Rate designs and scenario analysis for the 2017IEPR forecast include some of the following developments in residential rates:

IOUs

- Opt-in pilot of various rate designs began summer 2016 and continues through 2017
- Default pilot begins 2018 (700,000 customers)
- Residential Default rollout in 2019
- Decision on exempt customers in 2017
- Peak period shifting from late afternoon to early evening
- Decisions on rate cases in 2017 for 2018 implementation

SMUD

- Board has committed to default TOU
- Staff will model on the IOU timeline for now

POUs

- Some POUs are flattening their rate structures.

And for non-residential rates:

- IOUs have been transitioning small/medium commercial and agriculture customers to time-varying rates for several years.
- SDG&E and PG&E completed in 2016 and 2017.
- SCE will simultaneously implement new TOU periods and default CPP for 500,000 accounts in late 2018.
- Most effects are embedded or will be in 2017
- Load impact studies for already-defaulted customers can be used to estimate the incremental impact of final migration and TOU period changes.

Load estimates used for rate analyses will be adjusted for demand modifiers (efficiency, demand response, customer-side solar/PV, storage, etc.). Elasticities from a 2003-2004 Statewide Pricing Pilot (SPP) will be used. But SPP was based on opt-in customers and new residential TOU rates will be opt-out. SMUD has data from a more recent Smart Pricing Options Pilot (SPO) (2013-2014).

These data are for summer only, and include opt-in and opt-out samples. Interestingly, 1/3 of customers were not aware they were on a TOU rate. This has implications for modeling elasticities.

Also, there is the wrinkle of considering that many customers subscribe to programs spread their bills estimated evenly throughout the year to diminish the possibility of high/low months. It would seem that these programs would reduce the effects of TOU rates since costs/benefits of using energy differently are not as evident to customers. However, pilot studies seem to indicate that the responses/elasticities are similar between customers that are on these "smoothing" programs and customers that are not.

On April 1, 2017 the IOU demand-response load impact reports will be available. These include some analyses of rate designs and may be considered for the IEPR rate scenarios.

High- mid- and low- scenarios based on rate designs will be produced for the 2017 forecast. Next steps will include an August 3, 2017 IEPR workshop for preliminary results, August/September, consider new CPUC rate decisions, DAWG meeting in October and revised load impacts in in November 2017.

2:00 Suggestions for Improved Weather Normalization Analysis – Sheng, SCE

Energy Commission forecasts and SCE forecasts have produced different results for a number of years, while pursuing steps to better reconcile those differences with each IEPR (and, as appropriate, off-year IEPR) cycle.

Sources of the differences include

- Historical load data differences
  - CAISO EMS data versus SCE system records
- Weather data and definitions
  - CEC's Max631 versus SCE's max effective temperatures
  - Weather stations and weights
- Weather Normalization methodologies
  - Simulation compared to analytical approach
- Unique annual peak weather conditions
  - Typical versus abnormal

Recently, CAISO made the same EMS data used by Energy Commission available to the utilities. The presentation shows a difference of several hundred MW on the 2016 peak day and a difference in the peak hour (HE 16 v. HE 17).

CEC uses a weather parameter called "Max631" which is a weighted average of the hottest three days of the year (60% current day, 40% previous day, 10% next day). It tends to under predict in the SCE territory as compared with SCE's alternative variable " Max Effective Temperature." SCE finds that the minimum high temperature needs to be weighted more (they have interaction terms in the Max Effective Temp estimate). Also note that peak days may change quite a bit from month to month (and based on cloud cover, etc.

Kavalec -- Perhaps this normalization could be done after adding PV back in to the EMS data. Also, now that Energy Commission staff will have an hourly load model (per Vaid, earlier this morning) that will be less dependent on the weather peak day annual results.

Also note, data for the CPUC's Resource Adequacy proceeding only address EMS grid data – they do not don't have other data about generation, e.g., solar/PV. The 2017 IEPR will be the first year where staff will have adequate data to try and forecast PV.

2:30 Transportation Electrification – Weng-Gutierrez/Bahreinian, CEC

Idaho National Laboratory is leveraging an EV model that they have developed, using CA data to validate a simulation model being developed by Lawrence Berkeley National Laboratory. This project is about $250K. The model will have loadshapes and will be calibrated including true up of PHEV data and regional information. The work will be completed in April 2017 and will be available for the IEPR forecast. A final phase of the project, Phase 3 will be completed in June 2017. The study addresses EV grid integration.

The study covers light-duty EVs. Heavy-duty and off-road vehicles and electrification of sea ports, airports, high speed rail, etc. will be addressed separately. Chris Kavalec will contact the utilities separately regarding local information and projections for these uses.

The modeling is designed to account for the fact that some EV customers may not be on EV rates. In PG&E service territory only about 30% of the EV customers are on EV rates.

Energy Commission's most recent EV survey is the latest, most complete research in the industry. Results include self-report from customers regarding when they are using/charging, and residential/commercial customers. Staff will be able to estimate peak and off peak on distribution of charging behavior. It may be necessary to make assumptions regarding residential vs. commercial peak charging. The EV demand model uses an estimate of the distance from customer location to an EV charging station as a predictor of uptake. Better data regarding these distances would be extremely useful. Meeting SB 350 goals will require significant EV infrastructure (e.g., charging stations). CEC and ARB worked out a forecasting tool for the POUs to use in their Integrated Resource Plans (IRP). The tool translates POU plug-in hybrid vehicle forecasts to GHG reductions. However, there is currently an inconsistency in the tool vs. IEPR forecasts. JASC is working on this.

The EV penetration model uses an average annual EV-focused TOU rate, so it is expected to alter load shapes. The rate design should be revenue neutral on balance on whole. A new element for the IEPR forecast will be developing an EV, especially a peak value, for 13 regions.

The IEPR EV forecast workshop will be on on June 20, 2017.

Next steps:

We will have several DAWG meetings in spring/summer 2017 to review draft results as they are developed for a variety of forecast components, leading up to the August 3 IEPR workshop for the full draft CED results..

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