Resource Adequacy Methodology

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Agenda

- IOU service area short-term peak demand forecasts
- Coincidence factor (CF) adjustments
  - EMS vs OASIS data
  - Inter-year variability / using 1 – 3 years of data
  - Methods in other jurisdictions
- Plausibility adjustment – YearAhead process
  - Prorated adjustments to 1% of IEPR forecast
- Demand side management DSM allocation adjustment
- Future studies

- Short-term weather normalized (WN) non-coincident peak demand (NCP) load forecasts by TAC
  - Used to develop each IOU service area (SA) for EIPR
- In order to better capture weather sensitivity and weather patterns
  - 4-years CAISO EMS peak loads for June-September, 122 peak-producing summer days per year
  - Matching 30-years weather data (max and min temperatures) from 3-5 stations, weighted by station and aggregated by TAC
  - Variable selection: calendar variables as DOW, DOSS, month- and year-dummies, and moving average weighted max as max631 (.6/.3/.1)

- **Two-step time-series regression analysis relating logarithm peak-producing daily peak loads on weather and calendar variables to estimate their coefficients**
  - $\ln(\mathrm{mw}_{it}) = \alpha_i + \beta_1 \,\mathrm{max631}_{it} + \beta_2 \,\mathrm{min}_{it} + \beta_3 \,\mathrm{DOW}_{it} + \sum \gamma_j \,\mathrm{SPM}_{jt} + \sum \lambda_{ia} \,\mathrm{MD}_{iat} + \sum \delta_{ib} \,\mathrm{YD}_{ibt} + \beta_4 \,\mathrm{DOSS}_{it} + \sum \eta_{ic} \,\mathrm{SPD}_{ict} + \sum \nu_{id} \,(\mathrm{DOSS}_{it})^p + \varepsilon_{it}$

  i = TAC, t = time, α, βs, γ, λ, δ, η, ν the coefficients; a, b, c, d, indexes; p power exponent

- **Monte Carlo simulation based on the weather-related regression coefficients and historical weather variables produce the distribution of daily peak loads (3660 pts)**
- **Median from the distribution of each year max peak load (30 pts) represents the one-in-two WN NCP for each TAC**

IOU service area forecasts

- Medians (WN NCP) are projected two years ahead using growth factors based on the latest economic and demographic information
- Medians adjusted downward by critical peak pricing, peak time rebate and non-event based demand program impacts (real time or time of use pricing and permanent load shifting) form the basis of IEPR annual peak loads for the IOU service areas
- Annual peak loads for the IOU SAs with historic WN NCP and load shapes are used to derive monthly WN NCP and reconcile the aggregate LSEs year-ahead forecasts in each IUO SA for RA compliance

Coincidence factor (CF) adjustment

- CF reflects each LSE-specific load contribution to hourly load at the time of CAISO's peak loads
- CF = $\frac{\boldsymbol{LSEs\ load\ at\ time\ and\ hour\ of\ CAISOs\ peak\ loads}}{\boldsymbol{LSEs\ actual\ non-coincident\ peak\ load\ on\ any\ CAISO}\ \mathbf{time\ and}\ \boldsymbol{hour}}$
- LSE hourly load data and CAISO hourly system loads (EMS) for the three preceding years
- Five highest non-weather normalized CAISOs non-holidays weekday on-peak hours peak loads per month
- LSE specific monthly CF is calculated as the median of the five highest CF in a given month
- Median is used over the mean as an indicator of central tendency due to the skewed nature of the peak load values

Coincidence factor (CF) adjustment

- LSE-specific monthly CF is used in setting LSE's RA obligation for each month
- Proportionate shares at time CAISO CP are used in calculating the load factors to allocate RA capacity credit and import transfer rights
- CAISO's hourly load data can be sourced from either
  - Confidential EMS (Energy Management System)
  - Public OASIS (Open Access Same-Time Information System)

Analysis of variation between EMS vs OASIS

- **Results of comparing EMS vs OASIS data looking at the five highest hourly peak load levels and their times and dates for each month of the year over the previous three years**

Year	Number days non-match	Month
2013	3	2, 3, 8
2014	5	3, 7, 9, 11, 12
2015	2	2, 11
3 years – 12 months – 5CP dates = 180 days		

Analysis of variation between EMS vs OASIS

- **Results of comparing EMS vs OASIS data looking at the five highest hourly peak load levels over the previous three years**

Percent difference between EMS vs OASIS	Percent of total CFs
equal to 0 %	83 %
greater than 0 % but less than or equal to 1 %	7 %
greater than 1 % but less than or equal to 3 %	5 %
greater than 3 % but less than or equal to 5 %	2 %
Greater than5 %	3 %

Analysis of variation between EMS vs OASIS

- **Conclusion/Proposal for CF adjustments: to use OASIS if the dates and times for all the monthly five highest peaks are the same and there is less than a 3% difference in peak MW levels between EMS and OASIS. Otherwise to use EMS**

CF adjustment based on 1 – 3 years of data

- CF adjustments are based on the previous 1 to 3 years of historical hourly load data
- The concern of smaller sample sizes is that outlier events will have a disproportionate effect on the CFs while larger sample sizes better approximate historical trends across all month over the years
- The decision to use 1 or more years of data should depend on inter-year variability in CFs
- Inter-year variability
  - CF on 3-years of monthly historical peak loads will display inter-year variance ranging from 1% to 10%
  - Weather is the largest driver
  - Differences in load composition play a minor role

CF adjustment based on 1 – 3 years of data

- Inter-year variability analysis: inter-year variance of CF for each LSE by TAC and month (5 CFs per month per year for each of the three years for a total of 15 CFs)
  - To capture recent changes in load composition and to reduce the effects of extreme weather
- Analysis' results across LSEs reflects the following:
  - 66% of CFs showed less than 3% variance
  - 16% of CFs showed between 3% and 5% variance
  - 18% of CFs showed greater than 5% variance

CF adjustment based on 1 – 3 years of data

- Conclusion/Proposal to calculate monthly CFs based on the variation across the 3 years:
  - 1 year of data for LSEs with CFs less than 3%
  - 2 years of data for LSEs with CFs between 3% and 5%
  - 3 years of data for LSEs with CFs greater than 5%

Comparing results of CF adjustment methods

LSE	3 years – 5CP median absolute deviation CEC/PUC	3 years – 1CP median	3 years – 4CP median	3 years – 5CP median	1 year – 1CP single	1 year – 5CP median
LSE1	.901 / 1 yr	.897	.903	.911	.901	.901
LSE2	.907 / 2 yrs	.877	.882	.888	.965	.965
LSE3	.974 / 1 yr	.975	.976	.977	.965	.974
LSE4	.666 / 2 yrs	.619	.642	.660	.385	.454
LSE5	.834 / 2 yrs	.831	.839	.859	.854	.881
LSE6	.874 / 1 yr	.861	.822	.839	.874	.874

- The CF for LSE4 using 1 year 1CP is disproportionately impacted by an outlier in the most recent year of data

Methods in other jurisdictions

	WN CP	Number CPs	Frequency	Number years
PJM		5	Annual summer	1
ERCOT		4/mean	summer	1
Ontario		4 / 5	monthly	? / 1
BEG/PJM		5/mean	annual	1
DEB/PJM		5/mean	summer	1
DP&L/PJM	Y	5/mean	summer	
NIPSCO MISO		varies	monthly summer	7

Methods in other jurisdictions

	WN CP	Number CPs	Frequency	Number years	WN CF
PECO/PJM	Y	5/mean	summer	1	Y
IPL/MISO		1	monthly annual	7	Y

IPL/MISO
(1) Calculate the difference in temperature (ΔT) at times of CP and NCP
(2) Regress CF on ΔT
(3) Regress temperature at CP on temperature at NCP

Plausibility adjustment – YearAhead process

CEC	TAC	IOU SA	IOU SA adjusted
Short-term peak demand forecast WN NCP (MW)	13000	11960	11482

LSE	NCP submitted	CP	Adjustment for differences in SA forecasts (A)	CP
IOU B	9645	9452	558	10010
ESP	630	567		
CCA	913	776		
		10795		

(A) Difference between (11482 – (9452 + 585 + 786 – 43)) and 1% of 11482 times .95% = 558

Plausibility adjustment – YearAhead process

CEC	TAC	IOU SA	IOU SA adjusted
Short-term peak demand forecast WN NCP (MW)	13000	11960	11482

LSE	CP	Adjustment for plausibility and migrating load (B)	CP	DSM	Plausibility adjustment Prorated adjustments to 1% of IEPR forecast (C)	Final CP
IOU B			10010	38	26	9998
ESP	567	18	585	2	1	584
CCA	776	10	786	3	2	785
			11381	43		11367
(B) If 95% of CP from August Month-Ahead forecast is greater than the submitted forecast then 85% of the difference between CP from August Month-Ahead forecast and coincidence adjusted submitted forecasts						
(C) Difference between (11482 – (11381 – 43)) and 1% of 11482 = 29						

Demand Side Management allocations

- DSM allocation adjustments include EE, DR and DG programs in each of the three IOU service areas
- DSM allocation accounts for the proportion of the load impacts accruing to each LSE due to a portion of the distribution charge paid by their customers
- LSE allocation is based on its load share in each TAC area

Future studies

- **Investigate the use of residual probabilistic analytics and temperature simulation scenarios in development of the short-term peak load forecasts**
- **Investigate impacts of shifting peaks due to PV behind-the-meter on peak load forecast adjustment methodology**

And that's it

Any key questions to ask and answer?