Energy+Environmental Economics

Stochastic Modeling Status Report

California ISO Workshop

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Arne Olson
Andrew DeBenedictis
Ryan Jones

Agenda

+ **Description of methodology**
  - Generator Model: development of generator outage table
  - Net Load Model: development of net load curve
  - LOLP Model: integrates prior models and calculates metrics
+ **Preliminary results**
+ **Next steps**

Summary of Approach to Need Modeling

+ **Calculate LOLP-based metrics to determine need that is due to factors unrelated to system flexibility**
    - Load levels, imports, hydro, renewable production during peak hours
+ **Calibrate LOLP model to historical reserve margin (15-17%)**
    - Agree not to contest 15-17% reserve margin
    - Focus only on *changes* to traditional reserve margins caused by introduction of renewables
+ **Use CAISO model and PLEXOS to test for flexibility within otherwise reliable system**
    - Calibrate imports, renewables production, hydro production, etc. to expected values from LOLP model

Hourly LOLP Model Overview

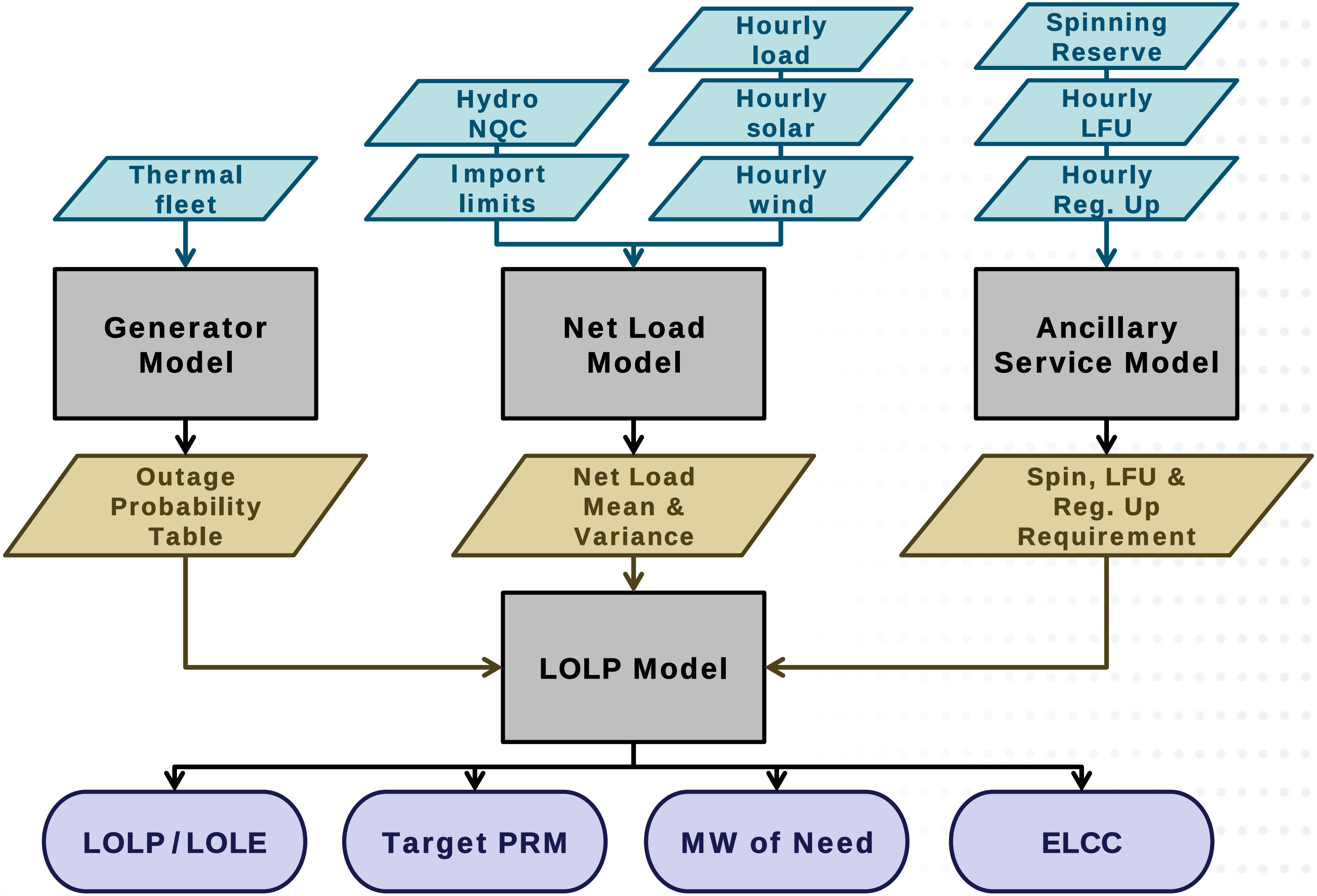
+ Five-step methodology:

- Step 1: calculate generator outage probability table
- Step 2: calculate hourly net load mean and variance
- Step 3: add reserve requirements for within-hour variability
- Step 4: calculate probability that G ≤ L for 8760 hours
- Step 5: add generation until LOLE = target reliability level

+ Additional useful calculations

- Target Planning Reserve Margin (i.e., reserve margin that achieves 1-day-in-10-year reliability)
- Renewables Effective Load-Carrying Capability (ELCC) at various penetration levels

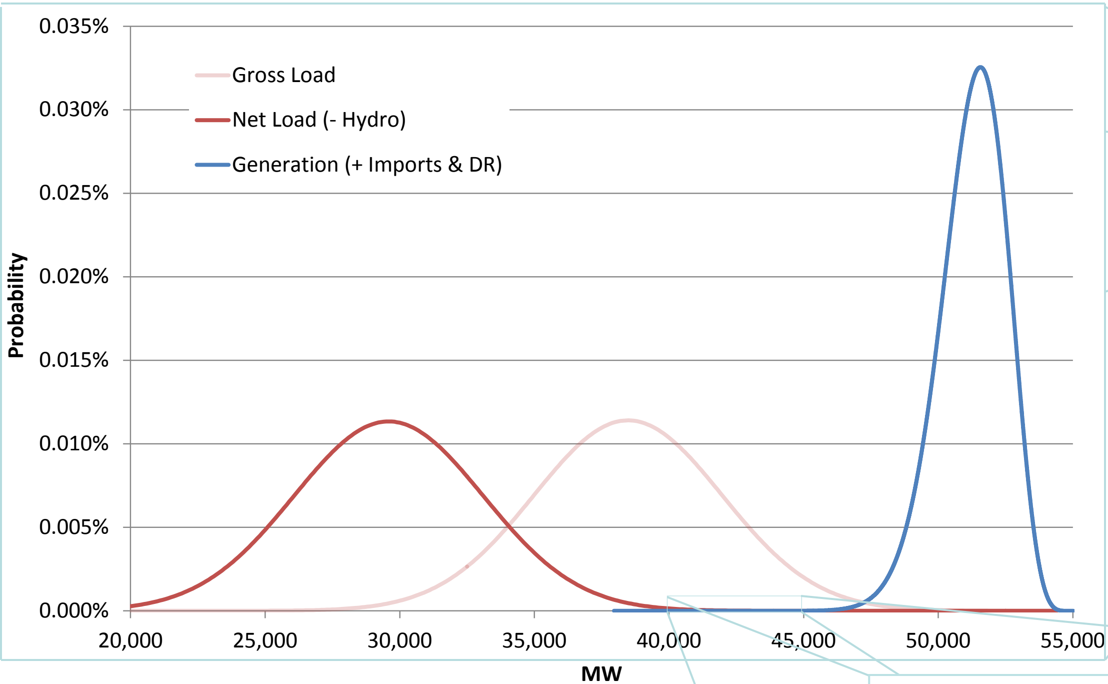
E3 LOLP Model Flow Chart

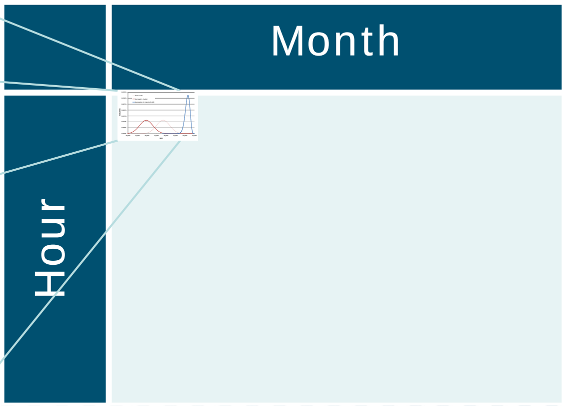


Metric Definition

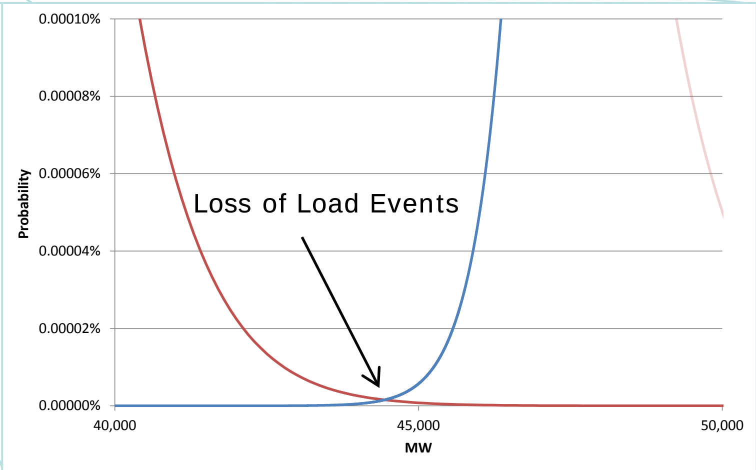
+ **Loss of Load Probability (LOLP)** is the probability that load will exceed generation in a given hour
+ **Loss of Load Expectation (LOLE)** is total number of hours wherein load exceeds generation. This is calculated as the sum of all hourly LOLP values during a given time period (e.g., a calendar year)
+ **Effective Load Carrying Capability (ELCC)** is the additional load met by an incremental generator while maintaining the same level of system reliability
+ **Target Planning Reserve Margin (TPRM)** is the planning reserve margin needed to meet a specific reliability standard, e.g., ‘1 day in 10 years’

Loss of Load Probability Occurs When Generation < Net Load + AS



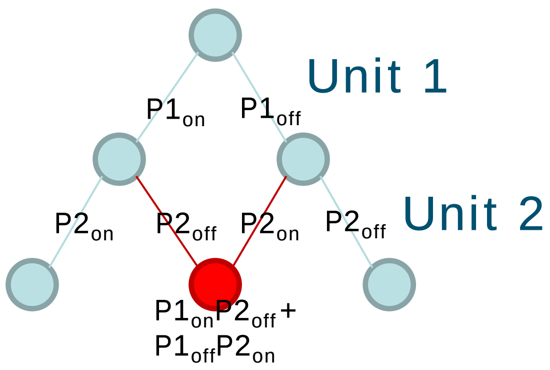


12 x 24 x 2 =
576 Total Distributions



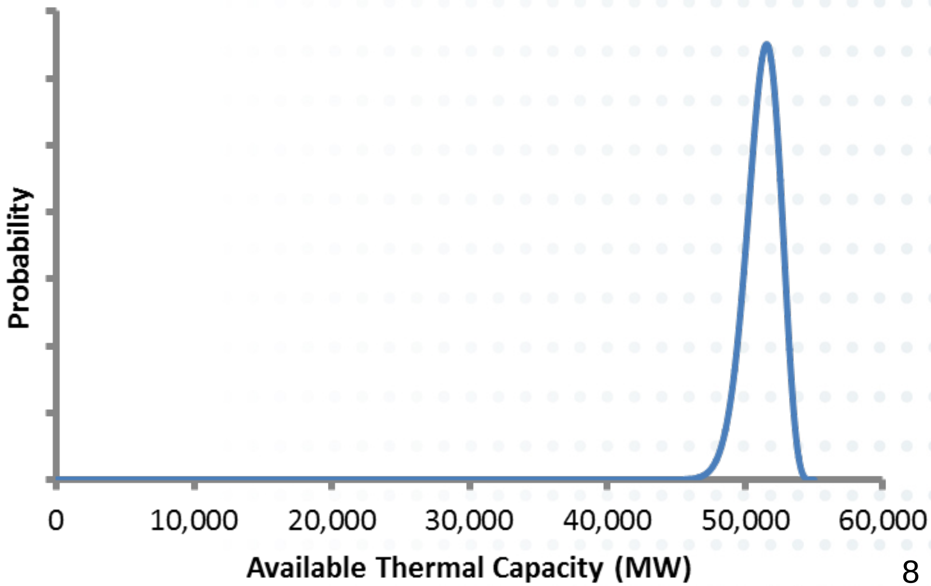
+ **The sum of the overlapping areas for all time slices gives the loss of load expectation for the entire year**

Description of Generator Model



Index *i*	*G* (Generation MW available)	*P* (Probability that exactly G MW available)
1	0 MW	Calculated using outage probability tree
I	55,000 MW	

- The probability of combinations of thermal unit forced outages are calculated by fully enumerating a binary outage probability tree



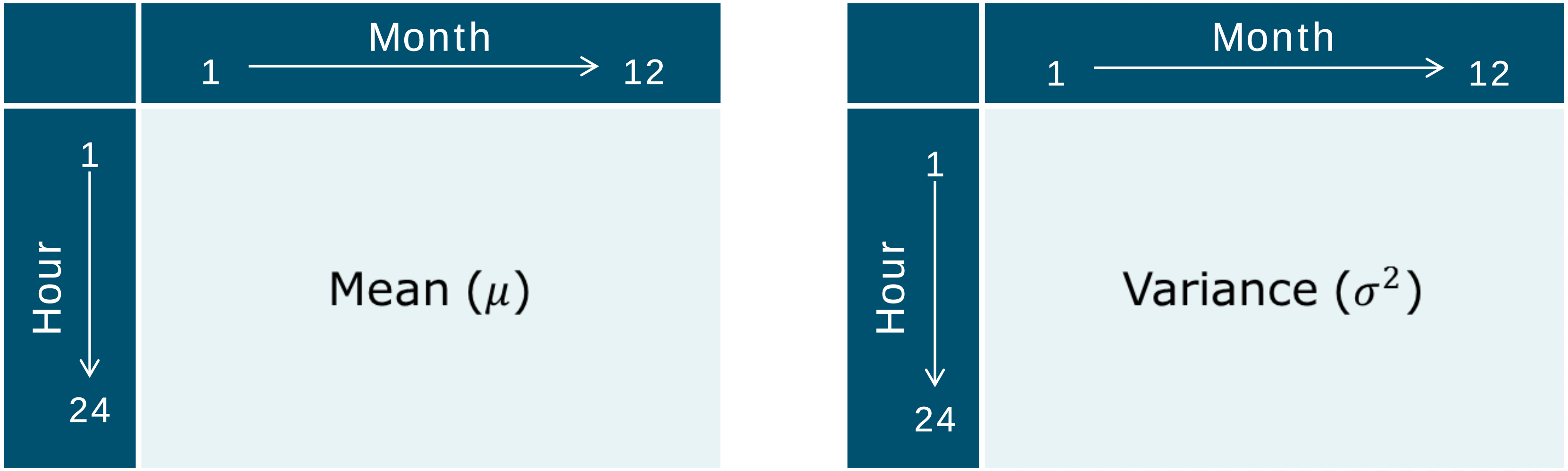
Description of Net Load Model

+ **The net load is gross load minus expected wind and solar output**
    - Mean and Variance for load, wind, and solar calculated from available data
    - Covariances are calculated using the years with concurrent data sets
    - Makes maximum use of all available data
+ **Net load mean and variance calculated for 576 annual time periods**
    - 24 x 12 x 2: 24 hours per day, 12 months, 2 day types (workday vs. weekend/holiday)

Data Availability

	Load	Solar	Wind
1990		X	
1991		X	
1992		X	
1993		X	
1994		X	
1995		X	
1996		X	
1997		X	
1998		X	
1999		X	
2000		X	
2001		X	
2002		X	
2003	X	X	
2004	X	X	X
2005	X	X	X
2006	X		X
2007	X		
2008	X		
2009	X		
2010	X		

12x24x2 Mean and Variance Tables



- **The mean (μ) and variance (σ^2) of gross load for each day type (L_d), wind output for each zone (W_i), and solar output for each zone and technology (S_j) are calculated for each month, hour and day type (workday or not)**
- **The Net Load mean and variance are then calculated using (where ρ_{jk} represents the correlation between data sets j and k):**
  - $\mu_{NetLoad} = \mu_L - \sum_i \mu_{W_i} - \sum_j \mu_{S_j}$
  - $\sigma_{NetLoad}^2 = \sigma_L^2 + \sum_i \sigma_{W_i}^2 + \sum_j \sigma_{S_j}^2 - 2\sum_i \sigma_{W_i}\sigma_L\,\rho_{W_iL} - 2\sum_i \sigma_{S_j}\sigma_L\,\rho_{S_jL} + 2\sum_i\sum_j \sigma_{W_i}\sigma_{S_j}\,\rho_{W_iS_j} + 2\sum_i\sum_{k>i} \sigma_{W_i}\sigma_{W_k}\,\rho_{W_iW_k} + 2\sum_j\sum_{k>j} \sigma_{S_j}\sigma_{S_k}\,\rho_{S_jS_k}$

Treatment of Hydro

- **Hydro dispatch is difficult to model**
  - Water budgets and storage horizons vary by project
  - Each project subject to minimum flow and maximum ramp constraints
- **E3 approach: subtract monthly hydro NQC value from load during each hour of month**
  - Assumes that hydro is ***available*** to dispatch up to NQC value during any hour of the month, if needed to avoid loss of load
  - Does ***not*** assume that hydro is *actually* dispatched to NQC value

Ancillary Service Model

- **System operator procures reserves to avoid problems within the hour**
- **Three types of reserves:**
  - Contingency reserve: needed to avoid firm load curtailment under Stage 3 emergency
  - Regulation reserve: needed to capture within-hour net load variability
  - Load following up: needed to avoid lost load due to net load forecast errors
- **Current Status:**
  - Current runs assume 2.5% of load for spinning reserve
  - Regulation and LFU not yet considered

LOLP Model

- **LOLP Model compares Net Load levels to generator outage table and calculates reliability metrics**
  - PRM, LOLE, TPRM, ELCC, Need
- **LOLE Standard – "1 day in 10 years" – can be interpreted in various ways:**
  - 1 hour in 10 years
  - 8 hours in 10 years
  - 24 hours in 10 years

Currently using 8 hours in 10 years, or 0.8 hours per year

- **For high renewables cases, focus on the *change* in PRM due to renewables**
  - Calculate TPRM for All-Gas Case first, then look at change in TPRM from addition of renewables

Key Assumptions

+ Key Assumptions for LOLP model

- Net load can be represented by a normal distribution
- Generation on the system is infinitely flexible
- No internal transmission constraints or local resource adequacy requirements
- Imports always available at specified limits
- Hydro always available to dispatch up to NQC value during each hour of month if needed to avoid loss of load
- Policy-driven demand reductions (EE, CSI, DR, CHP) are fixed and perfectly reliable
- Economic growth assumptions behind base load growth forecast are perfectly accurate
- Generation resources are fixed as per scenario specs

Preliminary Results

Four Cases / Sensitivities

	2009 Case	2020 All Gas Case	2020 All Gas Case: High Load Sensitivity	2020 High Load Trajectory Case
Peak Load (MW)	50,561	54,121	59,533	59,533
Actual Reserve Margin	36.8%	23.6%	9.9%	19.4%
Summer Peak Imports (MW)	14,886	14,886	14,886	13,410
Nameplate Wind (MW)	1,425	1,425	1,425	5,538
Nameplate Solar (MW)	437	437	437	8,985
Notes		Scheduled generator retirements and additions	10% higher load	Trajectory renewable build-out to 33% of load

2009 Case

- **Actual Planning Reserve Margin:** 36.8%
- **Peak Demand:** 50,561 MW
- **LOLE:** 0.00056 hours
- **Target Planning Reserve Margin**
  - **LOLE = 0.1:** 22.8%
  - **LOLE = 0.8:** 16.2%
  - **LOLE = 2.4:** 12.2%

No need using any LOLE target

- Range of Target Planning Reserve Margins consistent with current practices

2020 All-Gas Case

- **Actual Planning Reserve Margin:** 23.6%
- **Peak Demand:** 54,121 MW
- **LOLE:** 0.05852 hours
- **Target Planning Reserve Margin**
  - **LOLE = 0.1:** 22.1%
  - **LOLE = 0.8:** 15.5%
  - **LOLE = 2.4:** 11.6%

No need using any LOLE target

- Target reserve margins decrease as fleet becomes more reliable

2020 All Gas Case: High Load Sensitivity

- **Actual Planning Reserve Margin:** 9.9%
- **Peak Demand:** 59,533 MW
- **LOLE:** 3.304 hours
- **Target Planning Reserve Margin**
  - **LOLE = 0.1:** 21.6%
  - **LOLE = 0.8:** 15.0%
  - **LOLE = 2.4:** 11.1%

3,021 MW of need using 0.8 LOLE target

- 10% increase in load relative to All-Gas & Trajectory Case creates a need for additional capacity

2020 High Load Trajectory Case

- **Actual Planning Reserve Margin:** 19.4%
- **Peak Demand:** 59,533 MW
- **LOLE:** 0.6947 hours
- **Target Planning Reserve Margin**
  - **LOLE = 0.1:** 25.8%
  - **LOLE = 0.8:** 18.9%
  - **LOLE = 2.4:** 14.9%

Need: See Next Slide

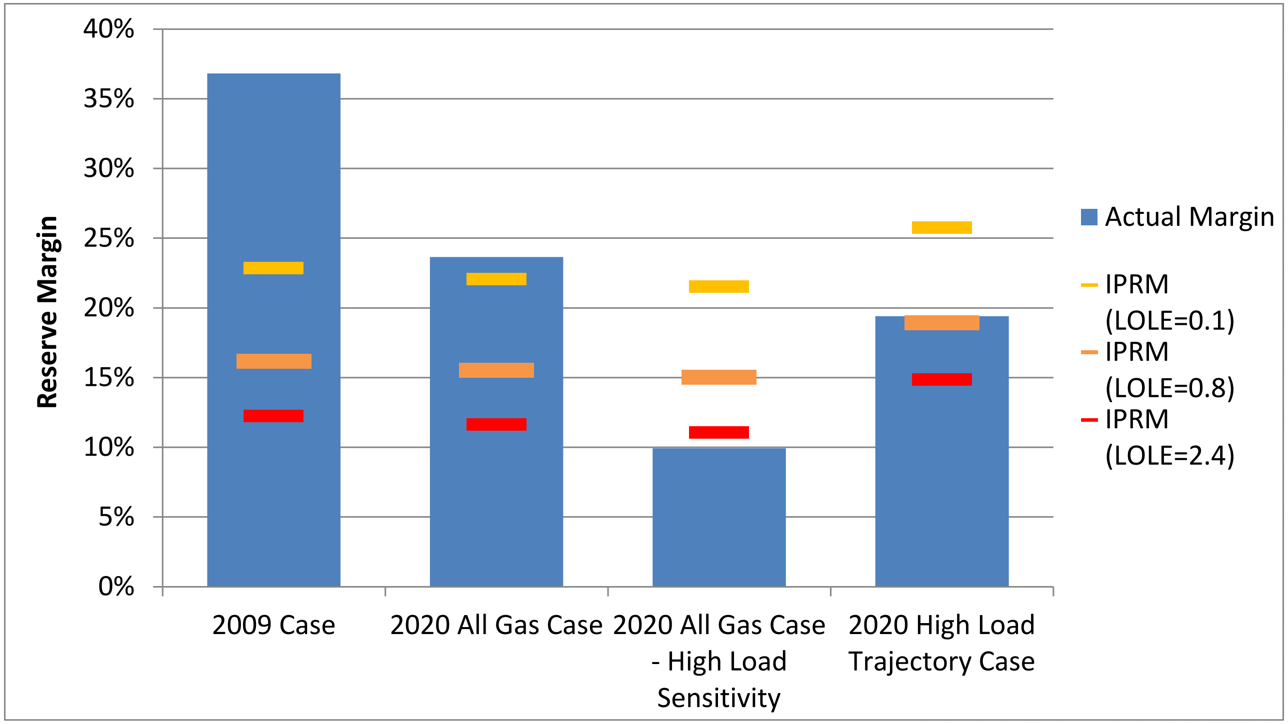
- Need to increase PRM by 3.9% due to renewables

Calculating Need in High Load Trajectory Case

1. Calculate All Gas TPRM	→	15.0%
2. Calculate Trajectory TPRM	→	18.9%
3. Define ΔTPRM = Trajectory TPRM – All Gas TPRM	→	3.9%
4. Add ΔTPRM to traditional 15-17% PRM to derive final PRM for Trajectory Case	→	18.9-20.9%
5. Multiply (1 + final PRM) by Peak Load to get Target NQC	→	70,795-71,986 MW
6. Compare to NQC of existing fleet	→	71,087 MW
7. Target NQC > fleet NQC indicates need for new generation	→	(292 MW) – 899 MW

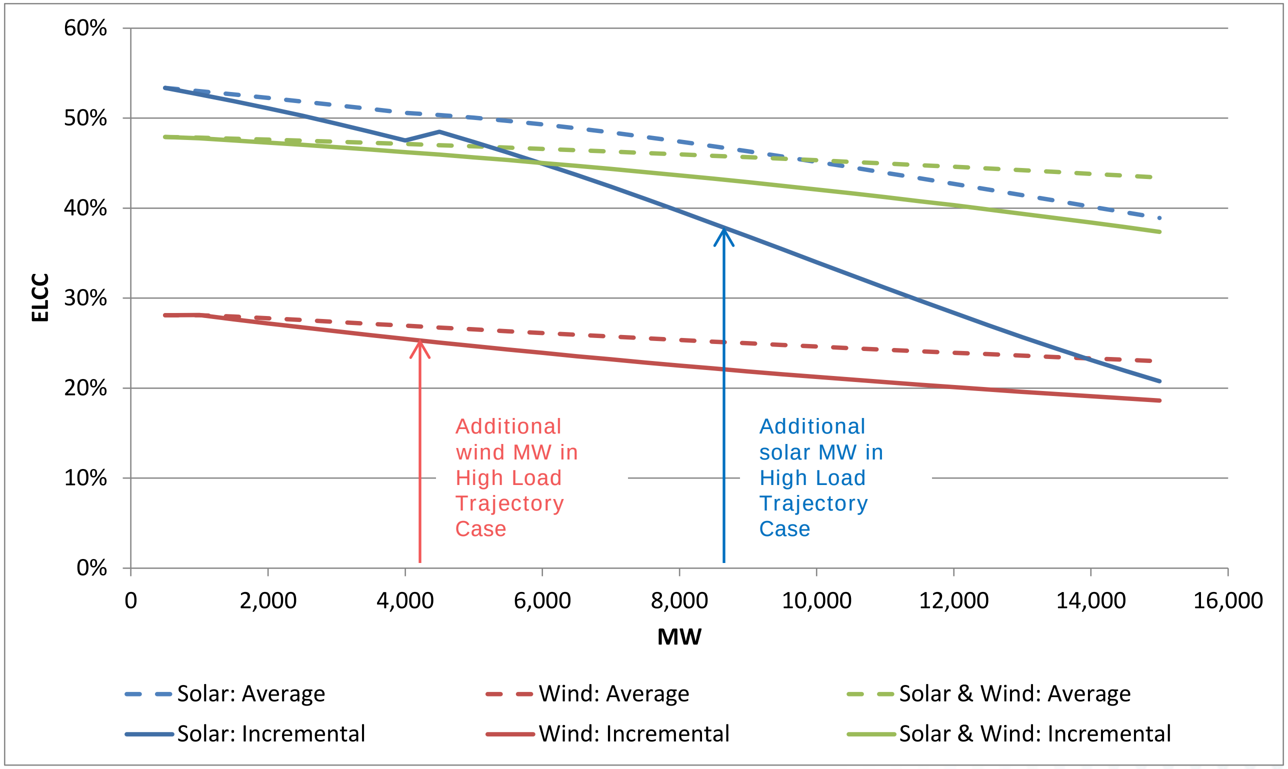
Need for high renewables case calculated as a function of the change in TPRM relative to All-Gas Case

Comparison Across Cases



- **Combined load growth to 2020 and generator retirements not enough to require additional resources in 2020**
  - However, 10% increase in load creates need due to shrinking actual reserve margin and relatively stable Target Planning Reserve Margin
- **3.9% increase in TPRM (LOLE = 0.8) from All Gas to Trajectory High Load Cases**
  - This translates to 2,332 NQC MW
- **Regulation and Load Following Up requirements NOT explicitly included**

ELCC as a Function of Renewables Penetration



- Shown for 2020 All Gas Case: High Load Sensitivity
  - MW additions are incremental to solar and wind MW already installed in 2009 Case
  - Mix of wind and solar sites maintains proportions of 2020 Trajectory Case
- Increasing renewable penetration leads to decreasing effectiveness
  - However, a 70/30 split of solar and wind maintains effectiveness

Next Steps

Next Steps

- Continued calibration and clean-up of base model
- Add Regulation and Load Following Up requirements (incremental to All-Gas Case)
- Evaluate change in TPRM if NQC values were updated to reflect ELCC of renewables
- Generate and review results from additional scenarios (Trajectory, Environmental)
- Compare results against PLEXOS need results

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Thank You!

Energy and Environmental Economics, Inc. (E3)
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
Tel 415-391-5100
Web http://www.ethree.com

Arne Olson, Partner (arne@ethree.com)
Andrew DeBenedictis, Senior Associate (andrew@ethree.com)
Ryan Jones, Associate (ryan.jones@ethree.com)