Load Impact Evaluation: 
**Non-residential Critical Peak Pricing**

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Presentation Outline

1. Program Description
2. *Ex-post* Methodology
3. *Ex-post* Load Impacts
4. *Ex-ante* Methodology
5. Enrollment Forecast
6. *Ex-ante* Load Impacts
1. CPP Program Description

- Critical Peak Pricing (CPP) is a price-based demand response (DR) program
  - Called Peak Day Pricing (PDP) at PG&E

- Customers receive a discount on most days in exchange for facing high (“critical”) prices on event days
  - *E.g.*, PG&E’s E-19 Secondary critical price = 1.20 $/kWh; demand credits of $5.70 in Peak Summer and $1.41 in Part-Peak Summer

- Customers receive day-ahead notification of CPP events

- PG&E and SCE events were from 2 to 6 p.m. while SDG&E events were from 11 a.m. to 6 p.m.
  - SDG&E’s event window changed to 2 to 6 p.m. in PY2018
1. CPP Program Description (2)

- CPP is the default rate for large (over 200kW) customers
  - At PG&E, default onto PDP happens after 12 months on a TOU rate
- Transitioning to CPP and the default C&I rate for small and medium business (SMB) customers
  - PG&E began in 2014; SDG&E began in 2015; and SCE will begin in Oct. 2018
  - CPP has been available as a voluntary rate to SMB customers
- The table below shows average event-day enrollments in PY2017 by utility and size group

<table>
<thead>
<tr>
<th>Size Group</th>
<th>PG&amp;E</th>
<th>SCE</th>
<th>SDG&amp;E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Large (Over 200kW)</td>
<td>1,982</td>
<td>2,292</td>
<td>1,281</td>
</tr>
<tr>
<td>Medium (20 to 199kW)</td>
<td>45,177</td>
<td>735</td>
<td>11,808</td>
</tr>
<tr>
<td>Small (Under 20kW)</td>
<td>158,006</td>
<td>82</td>
<td>Separate Study</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(133 NEM)</td>
<td></td>
</tr>
</tbody>
</table>
2. *Ex-post* Methodology

- Load impacts are estimated using matched control groups with difference-in-differences panel regression models
  - Matching conducted by utility, size group, industry group (combining some groups to increase the sample size), and climate zone
  - Within group, performed Euclidean distance matching using two 24-hour load profiles
    - PG&E and SCE used the hottest event-like days and the remaining event-like days
    - SDG&E used weekday and weekend event-like days (1 of 3 event days occurred on a weekend)
  - Preliminary matching on billing data and characteristics was performed where the pool of eligible control-group customers is large (SCE’s SMB customers)
2. Ex-post Methodology (2)

- Eligible pool of control-group customers consists of customers who opted out of CPP or have yet to be defaulted
  - Pool gets smaller as the default process proceeds
  - Despite shrinking pool of customers, match quality tends to be good (with some exceptions)
  - Estimated load impacts are not very sensitive to using customer-specific models in place of panel models for the largest + worst-matched customers
3. *Ex-post* Load Impacts: Events

<table>
<thead>
<tr>
<th>Date</th>
<th>Day of Week</th>
<th>PG&amp;E</th>
<th>SCE</th>
<th>SDG&amp;E</th>
</tr>
</thead>
<tbody>
<tr>
<td>6/16/2017</td>
<td>Friday</td>
<td>X</td>
<td></td>
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</tr>
<tr>
<td>6/19/2017</td>
<td>Monday</td>
<td>X</td>
<td>X</td>
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</tr>
<tr>
<td>6/20/2017</td>
<td>Tuesday</td>
<td>X</td>
<td>X</td>
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</tr>
<tr>
<td>6/22/2017</td>
<td>Thursday</td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6/23/2017</td>
<td>Friday</td>
<td>X</td>
<td></td>
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</tr>
<tr>
<td>7/6/2017</td>
<td>Thursday</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>7/7/2017</td>
<td>Friday</td>
<td>X</td>
<td>X</td>
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</tr>
<tr>
<td>7/27/2017</td>
<td>Thursday</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>7/31/2017</td>
<td>Monday</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>8/1/2017</td>
<td>Tuesday</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>8/2/2017</td>
<td>Wednesday</td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8/28/2017</td>
<td>Monday</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>8/29/2017</td>
<td>Tuesday</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>8/31/2017</td>
<td>Thursday</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>9/1/2017</td>
<td>Friday</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>9/2/2017</td>
<td>Saturday</td>
<td>X</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>9/5/2017</td>
<td>Tuesday</td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9/12/2017</td>
<td>Tuesday</td>
<td></td>
<td>X</td>
<td></td>
</tr>
</tbody>
</table>

Notes:
- The PG&E, SDG&E, and CAISO peak day was 9/1/2017. The SCE peak day was 8/30/2017.
## 3. Ex-post Load Impacts: Events (2)

<table>
<thead>
<tr>
<th>Utility</th>
<th>Hours of Availability</th>
<th>Hours of Actual Use</th>
<th>No. of Available Dispatches</th>
<th>No. of Actual Dispatches</th>
</tr>
</thead>
<tbody>
<tr>
<td>PG&amp;E</td>
<td>60</td>
<td>60</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>SCE</td>
<td>48</td>
<td>48</td>
<td>12</td>
<td>12</td>
</tr>
<tr>
<td>SDG&amp;E</td>
<td>126</td>
<td>21</td>
<td>18</td>
<td>3</td>
</tr>
</tbody>
</table>
3. Ex-post Load Impacts: PG&E Large C&I

- Average load impact = 22.4 MW, or 4.2% of ref. load
- 9/2 event was the hottest, but was also the only weekend event
- Aggregate load impact is ~27% lower than PY2016 (6% fewer customers, 22% lower per-customer load impact)
- PG&E peak hour load impact (9/1, HE 18) = 29.3 MW for large customers and 50.3 MW for the entire program
- CAISO peak hour load impact (9/1, HE 16) = 34.3 MW for large customers and 74.2 MW for the entire program
3. **Ex-post Load Impacts:**

**PG&E SMB**

- Average load impact = 15.0 MW, or 1.1% of ref. load
- Load impacts are quite variable across events (high = 30 MW; low = 4 MW)
- High variability of load impacts + low % impacts may indicate that estimates are affected by noise / omitted variables
3. **Ex-post Load Impacts:**

**SCE Large**

- Average load impact = 21.9 MW, or 3.9% of ref. load
- PY2016 average load impact was higher, at 34.4 MW (enrollment down 10%; per-customer load impact down 29%)
- SCE did not call an event on either the SCE or CAISO peak day
3. *Ex-post* Load Impacts: *SCE SMB*

- Average load impact = 0.9 MW, or 1.0% of ref. load
- One day with wrong-signed load impact; another with a zero load impact
- Large uncertainty bands compared to other groups
3. **Ex-post Load Impacts: SDG&E Large**

- Three events called on consecutive days, with the third event taking place on a Saturday
- Average weekday load impact = 18.0 MW, or 4.3% of ref. load
- Weekend load impact = 8.9 MW, or 2.9% of ref. load
- Load impact is substantially higher than the lone event in PY2016 (7.3 vs. 18.0 MW), with a higher per-customer load impact explaining the difference
- SDG&E and CAISO peak hour load impact (9/1, HE 16) = 16.3 MW for large customers and 17.4 MW including medium
3. *Ex-post* Load Impacts: SDG&E Medium

- Average weekday load impact = 1.0 MW, or 0.2% of ref. load (uncertainty band includes negative load impacts)
- Weekend load impact = -5.9 MW, or -1.6% of ref. load
- Wrong-signed weekend load impact likely due to lack of comparable non-event days (comparatively few weekend dates + event was very hot compared to other days)
- Weekday load impact was higher in 2016 (1.7% vs. 0.2%)
4. Ex-ante Methodology

- Ex-ante load impacts are based on ex-post estimates at the group level (e.g., size and LCA for PG&E)
- We examined the relationship between weather and load impacts, but did not find consistent relationships
- Ex-ante % load impact = ex-post average weekday % load impact, by hour and group
- Reference loads are simulated using the following:
  - Group-level average per-customer regressions to obtain effect of weather and time-period indicators on usage
  - Ex-ante day types and weather conditions (e.g., August peak month day in a utility-specific 1-in-2 weather year)
- SCE’s SMB forecast is based on the previous evaluation’s per-customer forecast scaled to the current enrollment forecast
## 5. Enrollment Forecast

<table>
<thead>
<tr>
<th>Utility</th>
<th>Size Group</th>
<th>2018 Enrollment</th>
<th>2019 Enrollment</th>
<th>2028 Enrollment</th>
</tr>
</thead>
<tbody>
<tr>
<td>PG&amp;E</td>
<td>Large</td>
<td>3,154</td>
<td>3,845</td>
<td>5,764</td>
</tr>
<tr>
<td></td>
<td>Medium</td>
<td>53,798</td>
<td>61,496</td>
<td>94,354</td>
</tr>
<tr>
<td></td>
<td>Small</td>
<td>181,295</td>
<td>203,633</td>
<td>291,644</td>
</tr>
<tr>
<td>SCE</td>
<td>Large</td>
<td>3,300</td>
<td>3,310</td>
<td>3,400</td>
</tr>
<tr>
<td></td>
<td>Medium</td>
<td>0</td>
<td>34,795</td>
<td>13,915</td>
</tr>
<tr>
<td></td>
<td>Small</td>
<td>0</td>
<td>215,205</td>
<td>86,082</td>
</tr>
<tr>
<td>SDG&amp;E</td>
<td>Large</td>
<td>1,422</td>
<td>1,470</td>
<td>1,791</td>
</tr>
<tr>
<td></td>
<td>Medium</td>
<td>10,879</td>
<td>10,770</td>
<td>9,839</td>
</tr>
</tbody>
</table>
6. Ex-ante Load Impacts: PG&E Large C&I

- Figure shows program-specific August average RA-window load impacts
- RA window includes a non-event hour, so the RA average is somewhat lower than the average event hour
- Changes in load impacts follow changes in enrollments across years
- 1-in-10 load impacts are somewhat higher than 1-in-2 load impacts
- Load impacts rise to around 40 MW in 2020 and remain there through 2028
6. Ex-ante Load Impacts: PG&E Medium

- Medium customer load impacts are somewhat more weather sensitive than large customer load impacts
- Load impacts rise to around 20 MW by 2020 and increase slowly through 2028
6. *Ex-ante* Load Impacts: 
**PG&E Small**

- Small customer impacts are forecast to rise more modestly over time, from around 2 MW to roughly 2.7 MW.
6. Ex-ante Load Impacts: 

**SCE Large**

- As with PG&E, the RA window includes one non-event hour, reducing the average load impact.
- The load impacts are quite stable throughout the forecast period, reflecting the stable enrollment forecast.
- Not much weather sensitivity in their load impacts.
- Load impact = ~27 MW.
6. Ex-ante Load Impacts:

**SCE Medium**

- The large reduction in load impacts between 2019 and 2020 reflects the underlying enrollment forecast.
- After default in October 2018, SCE assumes 50% opt out in the first year and an additional 30% in the second year due to expiring bill protection.
- Load impact stabilizes at approximately 4 MW in 2020-2028.
6. Ex-ante Load Impacts: SCE Small

- The small customer enrollment forecast has the same opt-out assumptions as the medium customer enrollment forecast.
- Load impact from 2020-2028 is approximately 3 MW.
6. Ex-ante Load Impacts: SDG&E Large

- SDG&E changed its event hours at the end of 2017, so the *ex-ante* event window matches that of PG&E and SCE
- We adapted the *ex-post* impacts to the new event window for the *ex-ante* study
- The figure shows RA window impacts, which include a non-event hour
- Load impacts grow steadily over the forecast period, consistent with the forecast ~2% increase in enrollments
- Load impacts reach 20 MW by 2028
6. **Ex-ante Load Impacts: SDG&E Medium**

- SDG&E forecasts medium customer enrollment to fall ~1% per year during the forecast period.
- Total load impact falls approximately 10% from 2018 to 2028.
6. **Ex-ante Load Impacts:**

*Ex-post vs. Ex-ante Load Impacts*

<table>
<thead>
<tr>
<th>Utility</th>
<th>Size Group</th>
<th>Load Impact (MW)</th>
<th>Enrollment</th>
<th>% LI</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Ex-post</td>
<td>Ex-ante</td>
<td>Ex-post</td>
<td>Ex-ante</td>
</tr>
<tr>
<td></td>
<td>Ex-post</td>
<td>Ex-ante</td>
<td>Ex-post</td>
<td>Ex-ante</td>
</tr>
<tr>
<td>PG&amp;E</td>
<td>Large</td>
<td>22.4</td>
<td>30.1</td>
<td>1,982</td>
</tr>
<tr>
<td></td>
<td>SMB</td>
<td>15.0</td>
<td>16.5</td>
<td>203,183</td>
</tr>
<tr>
<td>SCE</td>
<td>Large</td>
<td>21.9</td>
<td>29.8</td>
<td>2,292</td>
</tr>
<tr>
<td>SDG&amp;E</td>
<td>Large</td>
<td>18.0</td>
<td>18.5</td>
<td>1,281</td>
</tr>
<tr>
<td></td>
<td>Medium</td>
<td>1.0</td>
<td>0.8</td>
<td>11,808</td>
</tr>
</tbody>
</table>

- *Ex-post* impacts represent average event-hour (weekday only for SDG&E)
- *Ex-ante* impacts represent the average event hour in August 2018 peak day under utility-specific 1-in-2 weather conditions
- *Ex-ante* forecast is consistent with the *ex-post* estimates
- Changes in total load impacts are largely driven by changes in enrollment

Reduced % LI is due to a change in the distribution of customers across LCAs
Questions?

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