Agenda

- Legislative direction on SB32 feed-in tariff
- Framework for using avoided costs
- ‘Results’ from most recent avoided costs in CSI
- Complexities of delivering the value to ratepayers
- Proposal for discussion
(SB 2 1X): California Renewable Energy Resources Act amends provisions of the Public Utilities Code § 399.20(d) relating to price for generation

- Price no longer tied to the cost containment provision of the Renewables Portfolio Standard (RPS)
- Previously, pricing for electric generation under § 399.20 was tied to the Market Price Referent (MPR) – this connection to the MPR no longer applies

FIT based on avoided cost mechanism

- Supported by ratepayer indifference provision in SB 32 and § 399.20(e) of Public Utility Code
Framework for Using Avoided Costs

- Feed-in tariff price to be based on avoided renewable purchases plus additional ratepayer value

  Feed-in Tariff Price = RAM + Avoided Costs

- Energy Division proposed approach is to set a base price from the Renewable Auction Mechanism (RAM)
  - Provides a price for peaking as available, baseload, non-peaking as-available resources
  - Projects of size 20MW or under, location is unconstrained

- Additional avoided costs for feed-in tariff projects is set based on latest avoided costs
  - Additional value based on ‘local’ resources
  - Area-specific avoided costs
  - Avoided cost components; transmission, distribution, losses

*Energy + Environmental Economics*
Definition of ‘Local’ Resource

Definition for purposes of calculating additional value to ratepayers

• Renewable generators connected to the distribution system and serving load on the distribution system to which they are connected

• Evaluated using a ‘no backflow’ proxy meaning the output is never greater than the minimum load on distribution system

Since the feed-in tariff avoided cost is based on being a ‘local’ resource, CPUC proposes to require SB32 projects to be ‘local’

• This won’t affect most projects that are 3MW or less

• Limits large generators connected to small distribution systems
History of Avoided Costs in California

+ **CPUC has used area- and time-specific avoided costs for valuing distributed resources since 2004**
  - Provides long-term hourly forecast of the cost of delivering a kWh by hour to a specific location for 30 years
  - Locations have varied by climate zone

+ **Current uses of area-specific avoided costs cover all distributed resources**
  - Energy efficiency cost-effectiveness
  - Self-Generation Incentive Program cost-effectiveness
  - California Solar Initiative cost-effectiveness
  - Demand Response cost-effectiveness
Components of Avoided Costs

- Energy
- Generation Capacity
- Ancillary Services
- CO2, NOx, PM10 reductions
- Transmission Capacity
- Distribution Capacity
- Losses

These are provided by RAM projects as well, so are not additional value.

‘Local’ resources provided these values in addition to RAM projects.
Most Recent Update to Avoided Costs

+ E3 is near completion of a study of ‘local’ PV
  - Expected release in 4th Quarter 2011

+ Avoided costs reflect most recent information

+ Updates include
  - Most recent distribution capital expansion plans from utilities (however, vintage is still up to 3 years old)
  - Updated transmission marginal cost

+ Higher granularity on area differentiation
  - Distribution planning area rather than climate zone
Data Sources for Distribution Cost

- **Capital budget plans and load growth provided by each IOU in response to CPUC data request**
  - Capital budget plans isolated to load growth driven investments
  - Load growth by area provided in data request

- **Defining “Distribution Areas”**
  - SCE defined by SYS ID areas; broader than other IOUs
  - PG&E defined by DPAs
  - SDG&E by distribution substation

- **Adjustments for Capital Budget Horizon**
  - PG&E and SDG&E 4-year capital plans are adjusted to reflect longer horizons, assuming investments recur after 15 years in calculating avoided distribution value
  - SCE provided 9 year capital budget plans and no adjustment is being made to those
Distribution Avoided Costs by Planning Area ($/kW-year):

- PGE
- SCE
- SDGE
Network transmission similarly based on growth driven projects. Broader regional value

Transmission Capacity Value

<table>
<thead>
<tr>
<th></th>
<th>PG&amp;E $/kW-year</th>
<th>SCE $/kW-year</th>
<th>SDG&amp;E $/kW-year</th>
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<td>SDG&amp;E</td>
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Losses based on avoided cost estimates by utility

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<tr>
<th>TOU</th>
<th>Description</th>
<th>PG&amp;E</th>
<th>SCE</th>
<th>SDG&amp;E</th>
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<tbody>
<tr>
<td>1</td>
<td>Summer Peak</td>
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<td>1.081</td>
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<td>Summer Shoulder</td>
<td>1.073</td>
<td>1.080</td>
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<tr>
<td>3</td>
<td>Summer Off-Peak</td>
<td>1.057</td>
<td>1.073</td>
<td>1.068</td>
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<tr>
<td>4</td>
<td>Winter Peak</td>
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<tr>
<td>5</td>
<td>Winter Shoulder</td>
<td>1.090</td>
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<td>1.076</td>
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<tr>
<td>6</td>
<td>Winter Off-Peak</td>
<td>1.061</td>
<td>1.070</td>
<td>1.068</td>
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Calculating the Local Value by Distribution Area for each IOU

**Peaking As-available**
- Use simulated photovoltaic output for each substation
- Compute average avoided cost for T, D, and Losses

**Baseload**
- Use flat 8760 profile output
- Compute average avoided cost for T, D, and Losses

**Non-peaking As-available**
- Use flat 8760 profile output
- Multiply T by 20% NQC, remove D, and losses
Example: Avoided Cost Breakdown for an example SCE location

- **Peaking as Available**
  - Losses: $0.08
  - Transmission: $0.01
  - Distribution: $0.07

- **Baseload**
  - Losses: $0.01
  - Transmission: $0.01
  - Distribution: $0.07

- **Non-peaking as Available**
  - Losses: $0.01
  - Transmission: $0.01
  - Distribution: $0.07
COMPLEXITIES OF DELIVERING VALUE TO RATEPAYERS
Challenges of Capturing Value

**Distribution**
- Majority of avoided cost is distribution capacity savings resulting from deferral of distribution system investments.
- Most challenging to capture because of area-dependent nature and integration with distribution planning process.

**Transmission**
- Transmission avoided cost is lower, and location is less important.

**Losses**
- Least challenging to capture.
**Distribution Planning Process**

- **Load forecast of growth in an area**
  - Local area load forecast shows need for capacity expansion, or upgrades to meet reliability criteria

- **Develop distribution upgrade**
  - Preferred alternative is developed to solve the problem, minimum lifecycle revenue requirement

- **Establish capital budgeting plan**
  - Expected projects are compiled into a capital budgeting plan. Period of the plan depends on the utility, typically 5 to 10 years
**Illustrative Project**

- **Peak Load**
- **Load Growth Forecast**
- **5MW Load Reduction**
- **Capacity Limit**
- **New Capacity Limit**

- **Project Cost**
  - $10M
  - 2 year deferral
What Was Saved?

+ Original PV of revenue requirement (PVRR)
  - $10 million

+ Deferred PV of revenue requirement (PVRR)
  - $9 million

+ Savings of approximately
  - $1 million
  - $200/kW
  - $10/kW-year for 20 years

\[
\text{Assumptions: Inflation = 2%, WACC = 7.5%}
\]
How does marginal compare with actual savings?

- Marginal Value = $10/kW-year

- Actual value is “lumpy”
- Decreasing value with further deferrals
Distribution engineer feels confident in reliability when they actually delay the investment decision

- Sufficient peak load is reduced to defer the investment
- Utility planning process accommodates embedded load
Utility capital plans are continually updating, as are the load forecasts

- Vintage of the data in our analysis is up to 3 years old

Utility capital plans have shorter durations than the life of the renewable DG
PROPOSED APPROACH
Proposed Approach

- **Most recent avoided cost data sets the level of the additional value**
  - ‘Hot’ spots have one value
  - Other areas have another

- **Utilities choose areas where FIT DG would be most beneficial to the distribution system**
  - Areas are locked in for 3 to 5 years
  - Areas must encompass at least 5-10% of load depending on utility needs
  - Additional areas can be designated at any time
Avoided Cost – Peaking as Available

Avoided Cost $/kWh vs % of Peak Load MW

- SCE
- PG&E
- SDG&E
Average Avoided Cost – Peaking as Available

Note: Non-averaged avoided costs shown as semi-transparent line for comparison
* Proposal is that each utility identify the ‘hot spots’ in their service territory
Average Avoided Cost - Baseload

Note: Non-averaged avoided costs shown as semi-transparent line for comparison.

<table>
<thead>
<tr>
<th></th>
<th>Percent of Territory</th>
<th>Hot Spot Value $/kWh</th>
<th>Non-Hotspot Value $/kWh</th>
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<tbody>
<tr>
<td>SCE</td>
<td>10%</td>
<td>$0.0375</td>
<td>$0.0125</td>
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<tr>
<td>PG&amp;E</td>
<td>5%</td>
<td>$0.0150</td>
<td>$0.0100</td>
</tr>
<tr>
<td>SDG&amp;E</td>
<td>5%</td>
<td>$0.0125</td>
<td>$0.0075</td>
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</tbody>
</table>
Avoided Cost – Non Peaking as Available

Graph showing avoided cost in $/kWh as a function of % of peak load MW. The avoided cost is constant across different levels of peak load, indicating a linear relationship. The graph includes data for SCE, SDG&E, and PG&E.
Average Avoided Cost – Non Peaking as Available

Note: Non-averaged avoided costs shown as semi-transparent line for comparison
Thank You!

Contact Information

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