



Energy and Environmental Economics, Inc.

# Net Energy Metering Workshop

Nov. 20th, 2009, CPUC

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Energy and Environmental Economics, Inc.



# Agenda – NEM Workshop

- Background
  - NEM Report Requirements in PU Code 2827(c)(4)
  - Relationship to CSI and DG C/E Decision
  - Project Timeline
- Methodology and Preliminary Results of NEM
- Preview of CSI C/E Analysis Approach
- Building Block Details
  - PV Pro-forma Tool
  - Customer Bill Calculations
  - Avoided Costs



# NEM Study: Legislative Requirement

- NEM Cost/Benefit Study\* should include:
  - An assessment of the costs and benefits of net energy metering from the perspectives of both participating and non-participating ratepayers;
  - An assessment of wind energy co-metering
  - An assessment co-energy metering
  - An evaluation from the perspective of both participating and nonparticipating customers of the tradeoffs from different forms of net metering
  - An evaluation of options to replace the economic costs of different forms of net metering with a mechanism that more equitably balances the interests of participating and nonparticipating customers

\* Per PU Code 2827(c)(4)



# CPUC DG Cost-Benefit Decision

- Decision 09-08-026, August 20, 2009
  - To compare resource options, evaluate effectiveness of DG
  - Applies broadly, but intended specifically for CSI and SGIP
- Adopts the following principles:
  - Multiple Perspectives
  - Builds on EE avoided cost methodology
  - Uses actual rates and program data where available
  - Environmental benefits as in EE evaluation
  - Includes prospective evaluation of market transformation

# California Solar Initiative



Photo: Don Schramm, P-H-D EnterprisesStadt,  
7.74kw STC, May 06, 2008, Stevenson Ranch



## Long-term policy framework

- Uniform eligibility guidelines statewide for PV and other solar
- Incentives solar **performance**
- Incentives decline based on program demand

## Statewide Goals

- 3000 MW of DG Solar (CSI portion is 1940 MW)
- Self-sustaining solar industry free from ratepayer funded incentives



## Other CA DG Policies & Programs

- Self-generation Incentive Program (SGIP)
- Feed-in Tariffs (FiT)
- Utility-owned PV Programs
- Potentially Broad Technology mix

Fuel cells  
IC engines  
Microturbines  
Battery storage

Small wind  
Biomass  
Landfill Gas  
Micro hydro



# Deliverables

- NEM Report, Due to Legislature by 1/1/10
  - Provide legislature update on Net Energy Metering success, costs and benefits
- CSI C/E Report, Target Date of 3/31/10
  - Provide cost-effectiveness analysis of CSI including market transformation per decision
- DG Portfolio, mid-2010
  - Extend analysis to broader range of distributed generation cost-effectiveness applications

# About E3



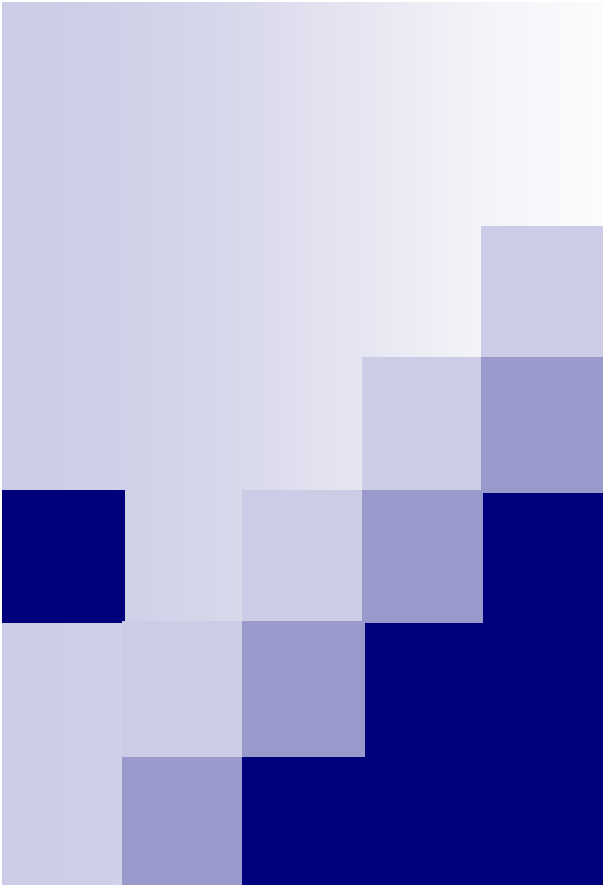
- E3 is an electricity consulting firm founded in 1989 in San Francisco
- Clients span local, state and federal government, small and large public and investor-owned electric utilities, and energy technology companies
- Experienced in marrying engineering-economic analysis with public stakeholder process
- Approximately 20 staff in energy economics, policy, and resource planning



# About Clean Power Research

- A clean energy focused consulting, research and software firm that was founded in 1998 by Tom Hoff
- CPR manages and operates a comprehensive suite of PV software tools which include: PowerClerk<sup>®</sup>, SolarAnywhere<sup>®</sup>, PVSimulator<sup>™</sup>, PowerTariffs, Clean Power Estimator<sup>®</sup> and PVCheck
- Offices in Seattle, WA and Napa, CA





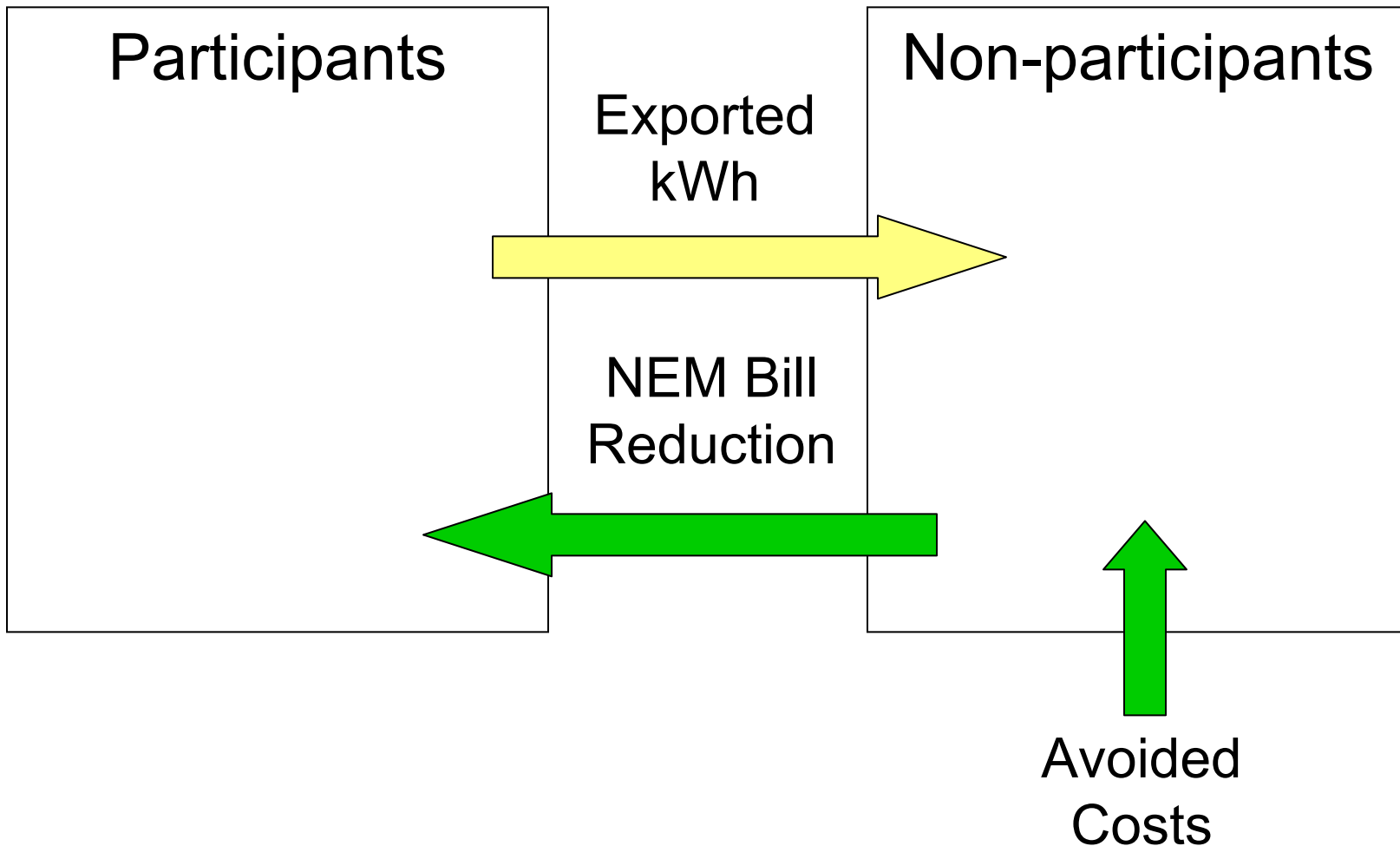
# Net Energy Metering Methodology & Results



# NEM Report – Primary Research Questions

1. Are many Californians taking advantage of the NEM rules?
2. What are the overall costs and benefits of NEM from participant & non-participant perspectives?
3. What are the differences in NEM costs and benefits by application?
4. What are the implications of key program rules and requirements?

# Participating / Non-Participating Customer Perspectives of NEM





# Analysis Steps for NEM Report

1. Analysis of existing system performance
2. Analysis of billing data and installs
3. Bill calculations by rate and segment
4. Utility avoided cost calculations
5. Net NEM cost by rate and customer size

# Progress to November 20

- Analysis process is moving along
- Expected completion 1<sup>st</sup> week of December

Analysis Step	PG&E	SCE	SDG&E
Data received	+	+	+
Step 1: Performance	+	+	~
Step 2: Process Billing Data	+	~	~
Step 3: Compute Bills	Examples	~	~
Step 4: Compute avoided costs	Examples	~	~
Step 5: Compute net value	Examples	~	~

# Installed Capacity by Technology

PV Systems make up 93% of NEM system capacity

## PG&E

	Capacity (kW)	Percentage
<b>Solar PV Technology</b>	<b>262707</b>	<b>96.1%</b>
<i>Fuel Cell</i>	650	0.2%
<i>Fuel Cell/Solar</i>	1135	0.4%
<i>Internal Combustion/Solar</i>	825	0.3%
<i>Internal Combustion Engine</i>	365	0.1%
<i>Methane Internal Combustion</i>	700	0.3%
<i>Microturbine/Solar</i>	5665	2.1%
<i>Wind Turbine</i>	649	0.2%
<i>Wind/Solar</i>	558	0.2%
<b>Non-Solar PV and Mixed Technologies</b>	<b>10547</b>	<b>3.9%</b>
<i>Total</i>	<b>273254</b>	<b>100.0%</b>

## SDG&E

	Capacity (kW)	Percentage
<b>Solar PV Technology</b>	<b>50989</b>	<b>95%</b>
<i>Wind</i>	26.3	0.0%
<i>Wind/Solar</i>	52.2	0.1%
<i>Biogas</i>	130	0.2%
<i>Fuel Cell</i>	2250	4.2%
<b>Non-Solar PV and Mixed Technologies</b>	<b>2458.5</b>	<b>5%</b>
<i>Total</i>	<b>53448</b>	<b>100%</b>

## SCE

	Capacity (kW)	Percentage
<b>Solar PV Technology</b>	<b>123775</b>	<b>86%</b>
<b>Non-Solar PV and Mixed Technologies</b>	<b>20661</b>	<b>14%</b>
<i>Total</i>	<b>144436</b>	<b>100%</b>

## TOTAL

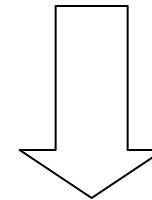
	Capacity (kW)	Percentage
<b>Solar PV Technology</b>	<b>437471</b>	<b>93%</b>
<b>Non-Solar PV and Mixed Technologies</b>	<b>33666</b>	<b>7%</b>
<i>Total</i>	<b>471137</b>	<b>100%</b>

NEM analysis completed has focused on PV, other technologies will be included in final NEM report.

# 1. Analysis of Existing Systems

- Analysis of existing PV installations to calculate capacity factor
  - $Cap\ Factor = f(\text{kW ac, customer type, location})$
  - Annual Output = Cap. Factor \* kW ac \* hours
- Compare sample to population (# actual vs. # sampled)
  - Poor sampling will require simulation or other billing data approaches
- Results show:
  - Capacity Factors broken down by size, customer type, and location
  - Determine representative selection of PV output profiles
    - {A, B, C, D, E}

SGIP, PMRS, PBI, load research interval data



Climate Zone	Customer Type	PV System Size	Annual Cap Factor
COAST	Non-Res	10 to 100 kW	13.7%
COAST	Residential	<= 10 kW	18.5%
DESERT/MTNS	Non-Res	100 to 500 kW	2.5%
DESERT/MTNS	Residential	<= 10 kW	13.2%
HILLS	Non-Res	10 to 100 kW	15.6%
HILLS	Non-Res	100 to 500 kW	12.8%
HILLS	Non-Res	> 500 kW	6.7%
HILLS	Residential	10 to 100 kW	47.3%
HILLS	Residential	<= 10 kW	20.5%
VALLEY	Non-Res	10 to 100 kW	16.7%
VALLEY	Non-Res	100 to 500 kW	5.8%
VALLEY	Non-Res	> 500 kW	11.9%
VALLEY	Residential	10 to 100 kW	13.5%
VALLEY	Residential	<= 10 kW	14.6%

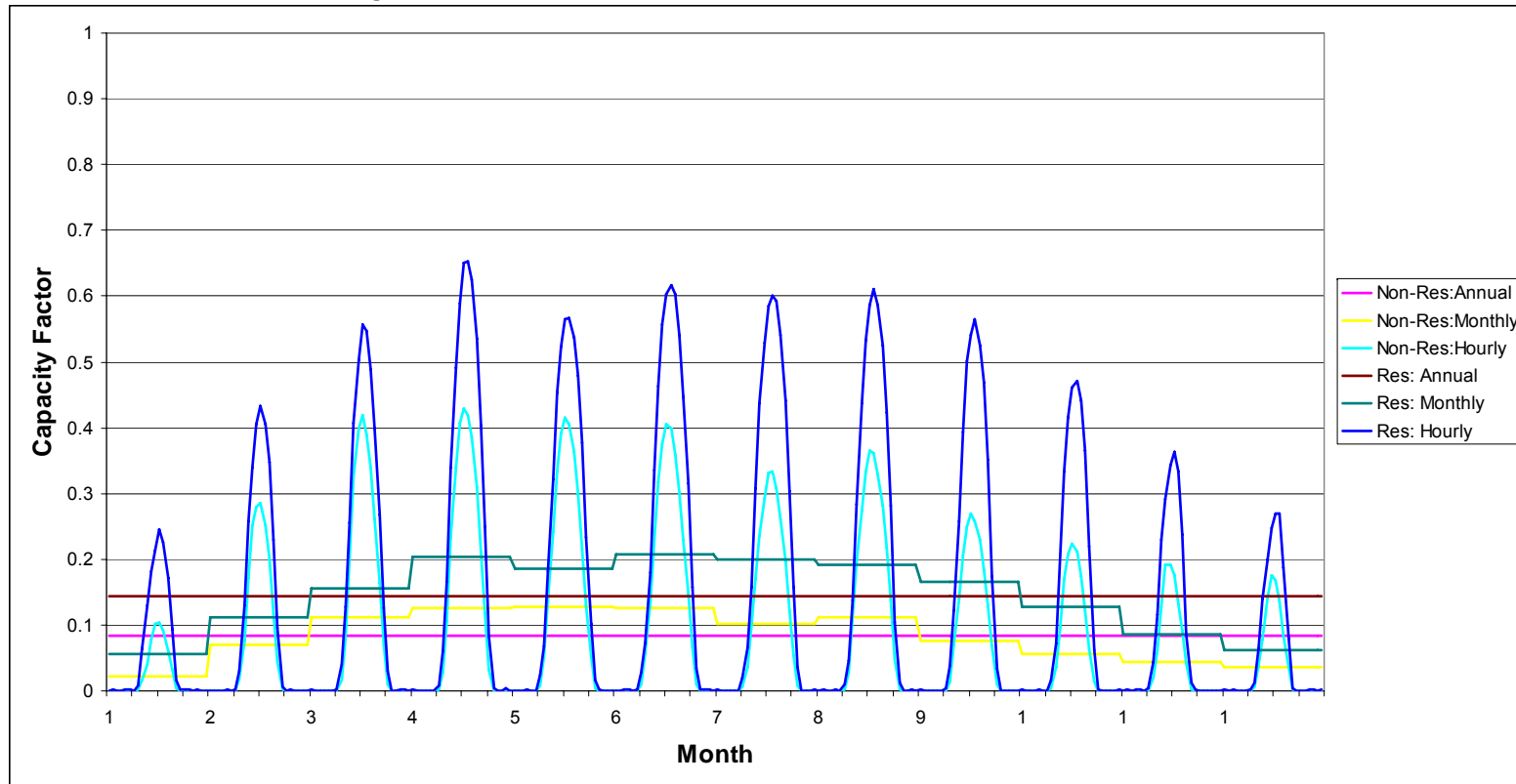
# PG&E & SCE PV Output Data

Distribution of PV output data for PG&E and SCE – complete 2008 data

Utility	Climate Zone	Customer Type	# Accounts	Min System Size (kW)	Max System Size (kW)
PGE	Coast	Non-Res	3	14.0	30.0
PGE	Coast	Residential	2	4.0	6.0
PGE	Desert/Mtns	Non-Res	2	500.0	500.0
PGE	Desert/Mtns	Residential	6	3.0	9.9
PGE	Hills	Non-Res	6	32.5	900.0
PGE	Hills	Residential	5	3.5	42.0
PGE	Valley	Non-Res	9	32.0	1000.0
PGE	Valley	Residential	11	3.0	18.0
SCE	5	Residential	6	2.4	5.9
SCE	6	Non-Res	3	4.4	21.3
SCE	6	Residential	39	1.1	18.7
SCE	8	Non-Res	1	9.1	9.1
SCE	8	Residential	15	2.0	9.7
SCE	9	Non-Res	2	89.8	347.0
SCE	9	Residential	35	1.0	19.2
SCE	10	Non-Res	6	7.3	320.5
SCE	10	Residential	13	1.3	8.5
SCE	13	Residential	11	1.2	10.2
SCE	14	Residential	10	2.1	6.0
SCE	15	Residential	6	4.9	28.3
SCE	16	Residential	2	5.4	11.9

193 accounts out of 2808 gathered had complete 2008 data.  
Difficult to use the fractions of PV output data for this analysis.

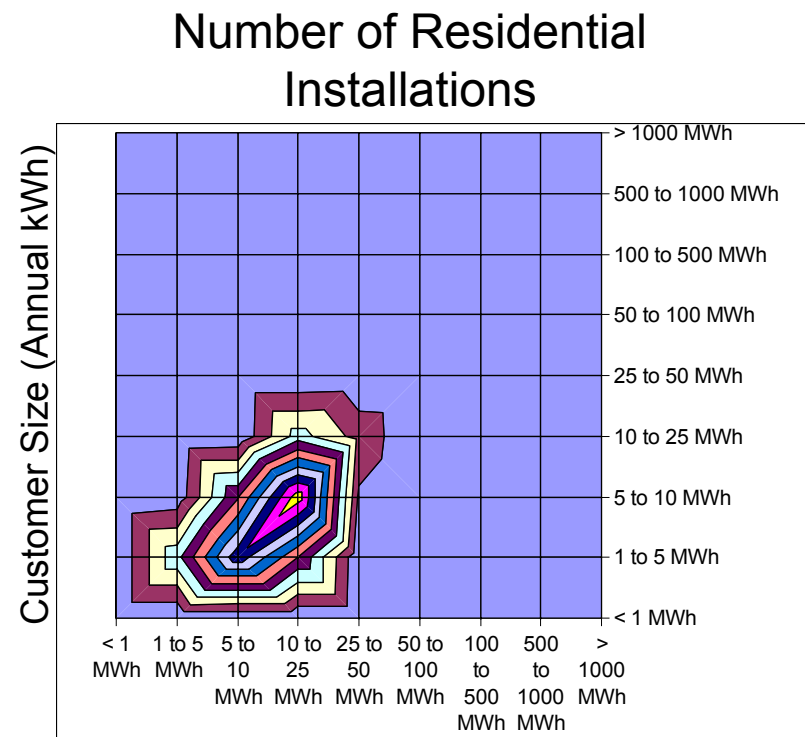
# 1. Analysis of Existing Systems – Preliminary look at some PG&E data



- ITRON and PG&E metered data
- Calendar Year 2008, Climate Zone = Valley
- 9 Non-Residential PV systems, ranging in size from 32 to 1000 kW
- 11 Residential PV systems, ranging in size from 3 to 18 kW

## 2. Analysis of Billing Data and Installed Systems by Customer

- Categorize customers by:
  - Customer Type
  - Climate Zone
- Count the number of customers in each segment of customer size and PV output
- Tabulate other metrics such as the share of PV generation that is exported by category

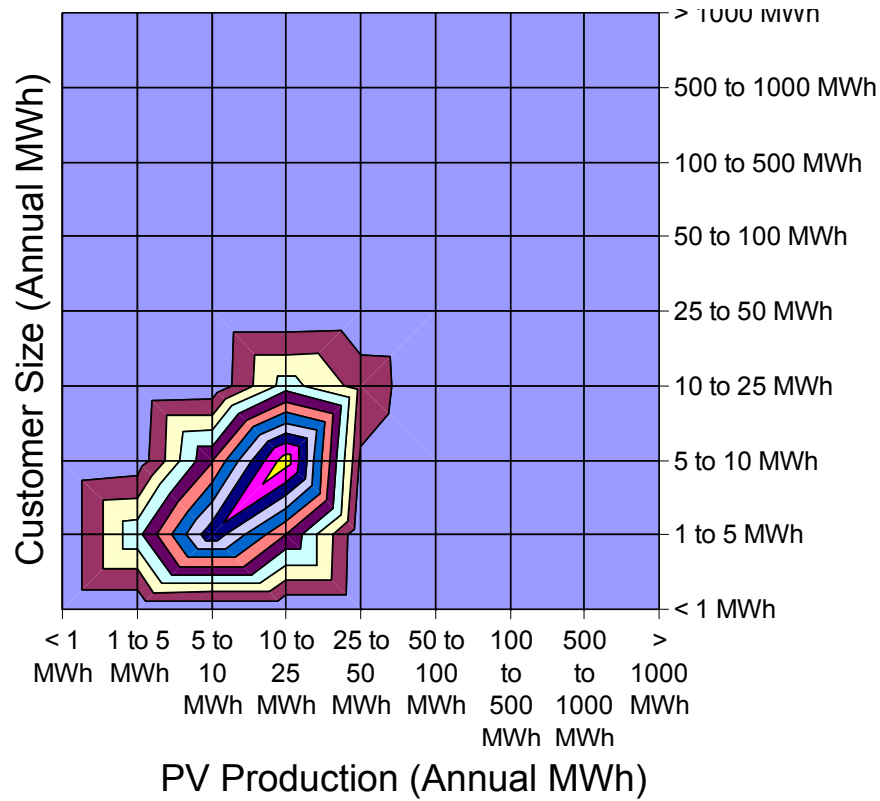


=kWAC \* Cap Factor

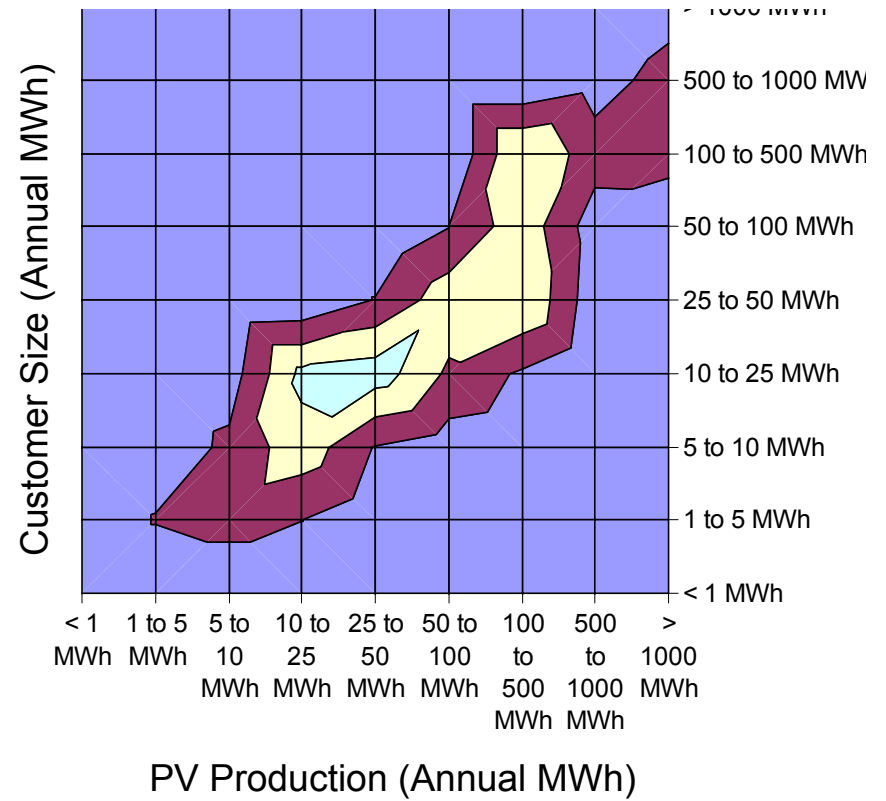
=Net Consumption + PV Production

# Distribution of PG&E PV Installs

Number of Residential Installations



Number of Non-Residential Installations



# 3. Bill Calculations by Category

## Where data is available

- Calculate bill impacts directly

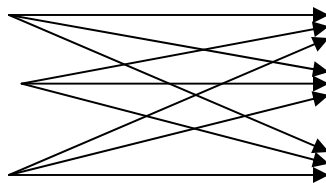
## Where data is not available

- Use load research shapes and metered PV output shapes
- For each category, run bill calculations based on combinations of:
  - customer load shapes (statistical profiles)
  - PV output shapes (selected from Step 1)
- Focus on categories with the majority of customers

- Customer shape (8760) -

- Shape 1
- Shape 2
- Shape 3

.....



- PV output shape

- Shape A
- Shape B
- Shape C

.....

Up to 9 combinations per segment

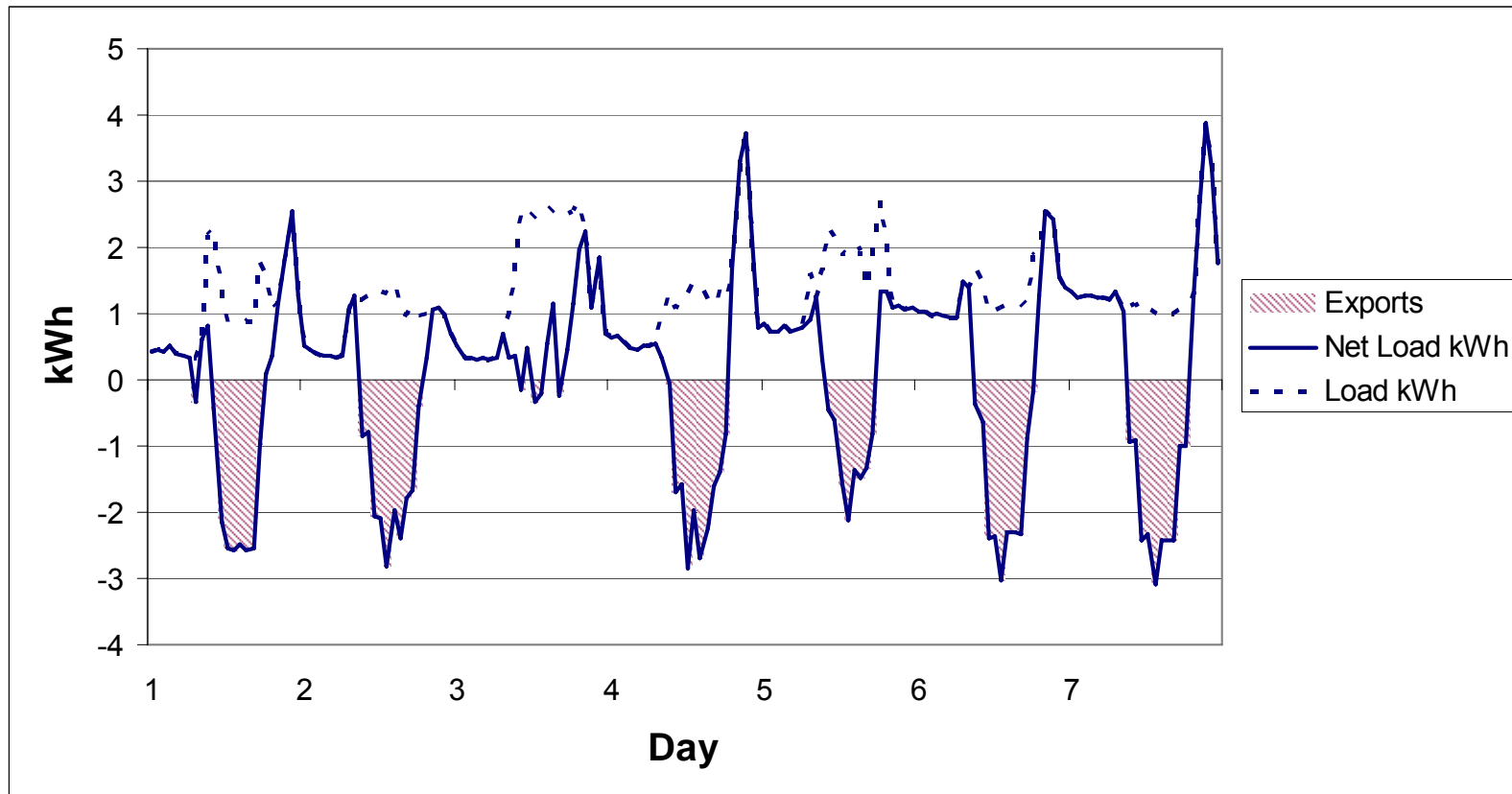
# Example Net Load Shape: June 1-7

Climate Zone: Coast

Customer Type: Residential

Consumption Category: 10 to 25 MWh

Generation Category: 5 to 10 MWh



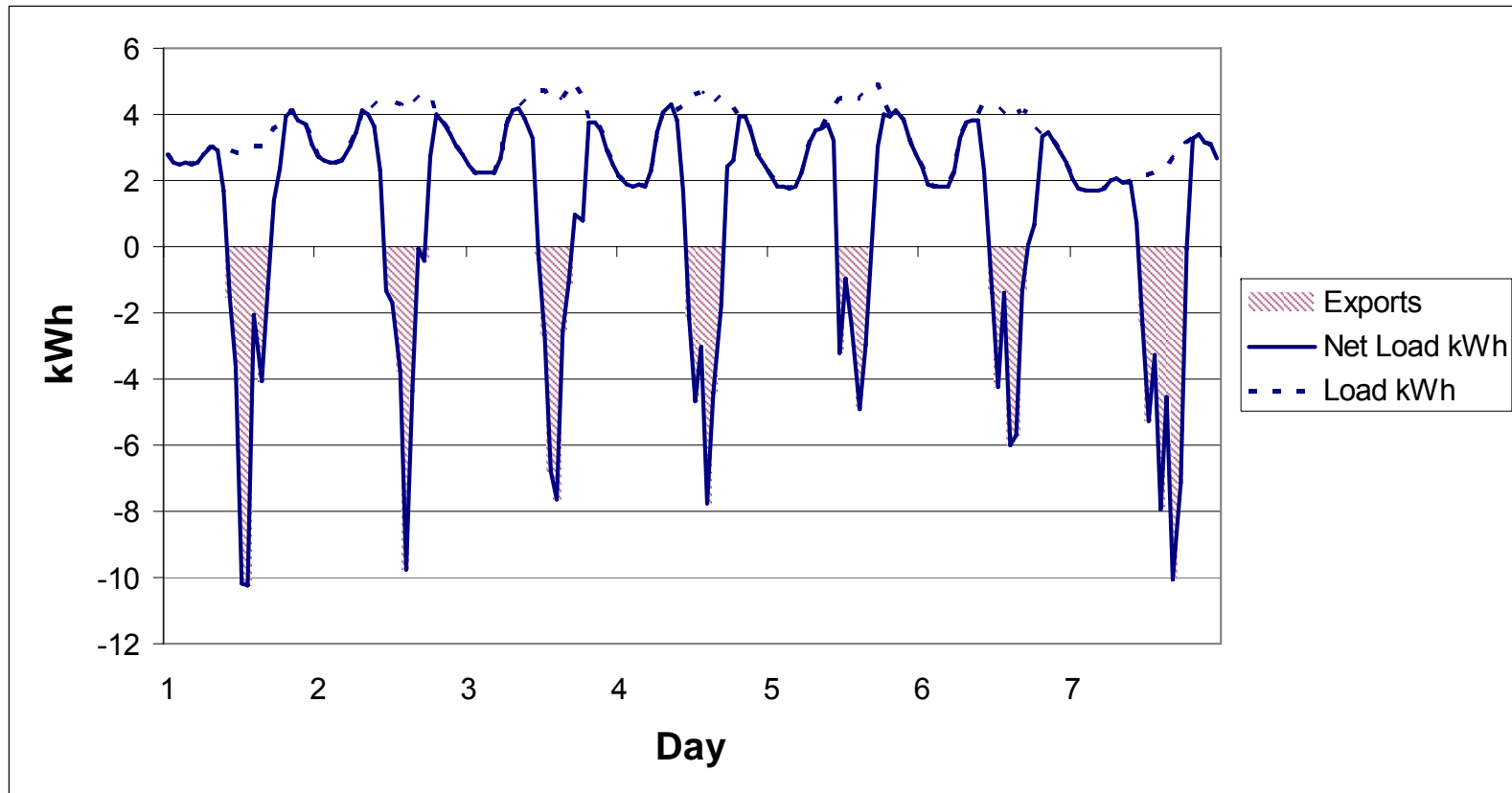
# Example Net Load Shape: June 1-7

Climate Zone: Coast

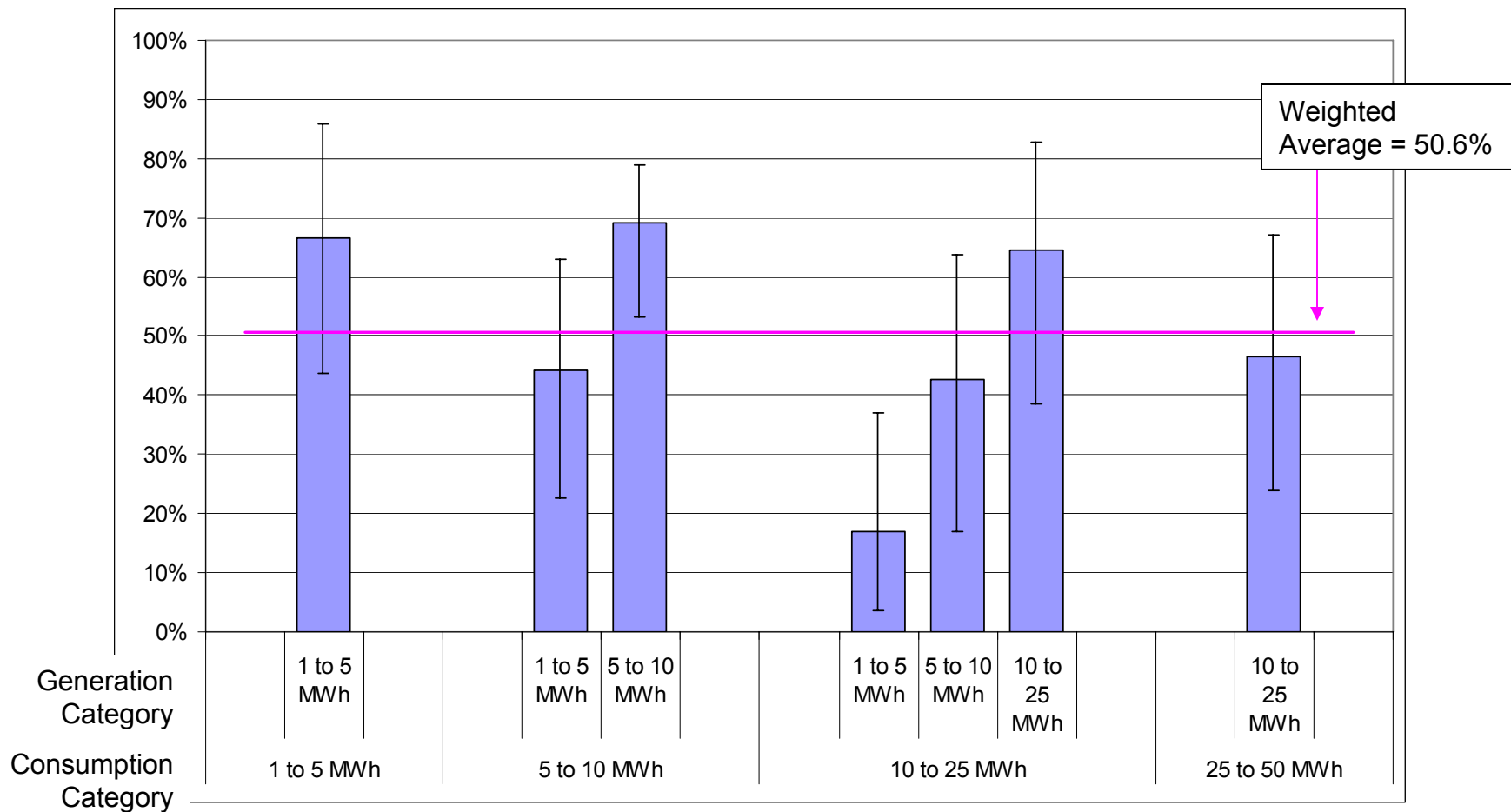
Customer Type: Non-Residential

Consumption Category: 25 to 50 MWh

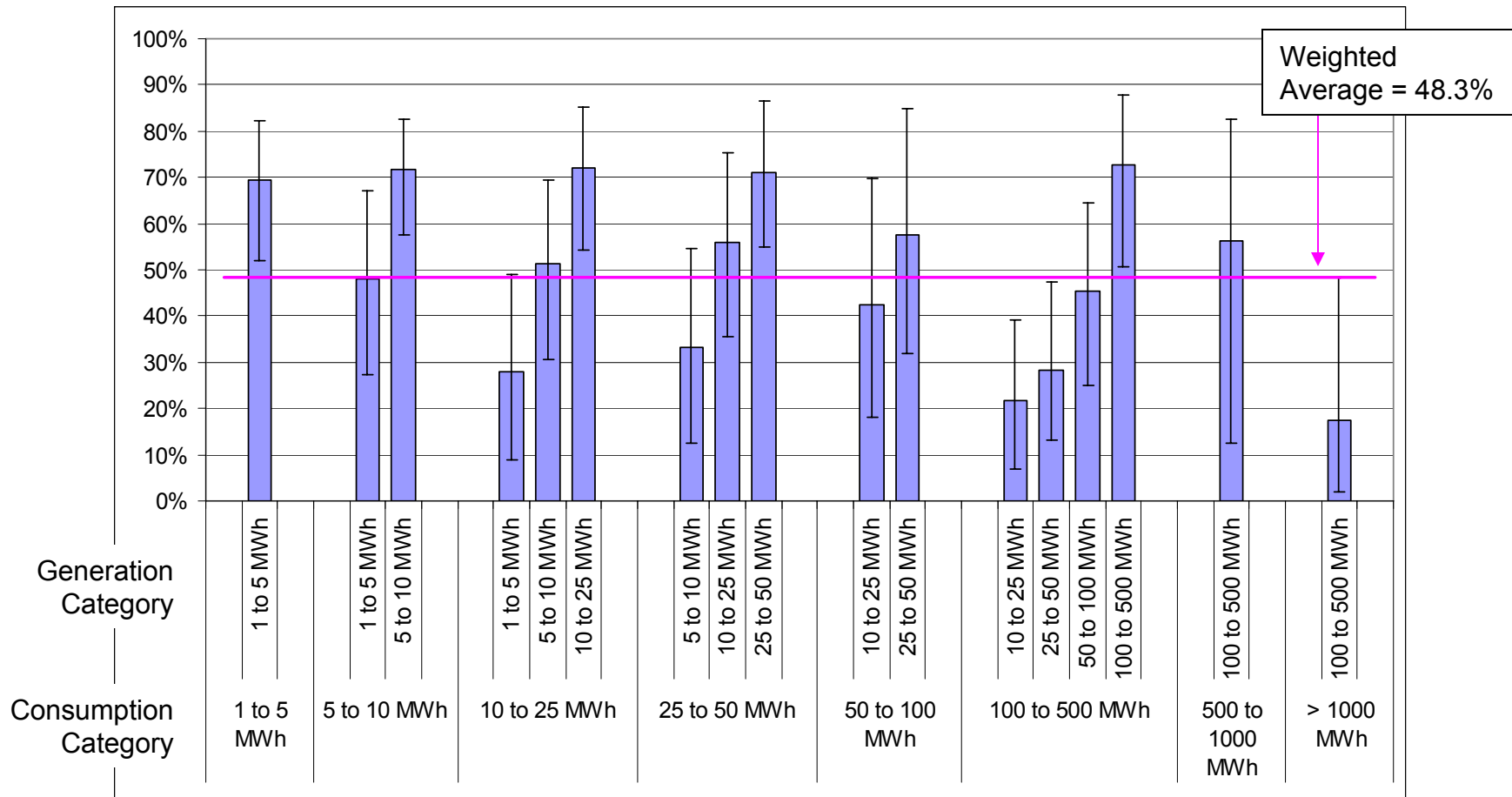
Generation Category: 10 to 25 MWh



# Percent of Generation Exported to Grid: PG&E Residential



# Percent of Generation Exported to Grid: PG&E Non-Residential



# Output from Bill Calculation Tool

- January Bill
- PG&E E1 Rate
- Coastal Zone
- Area T
- Bill with and without credit for exported kWh
- Repeat for Annual Bill difference

## Without NEM Credit

Residential Service (Rate E1 Area T)	Quantity	Price	Total
<b>Winter</b>			
Hours in Season	744.00000		
Energy Consumption			
Tier 0	303.71507	0.11551	\$35.08
Tier 1	90.70685	0.13129	\$11.91
Tier 2	213.00822	0.26098	\$55.59
Tier 3	242.73119	0.38086	\$92.45
Minimum Bill			\$4.50
<b>Total Bill for Billing Cycle</b>			<b>\$195.03</b>

## With NEM Credit

<b>Winter</b>			
Hours in Season	744.00000		
Energy Consumption			
Tier 0	303.71507	0.11551	\$35.08
Tier 1	90.70685	0.13129	\$11.91
Tier 2	213.00822	0.26098	\$55.59
Tier 3	175.11131	0.38086	\$66.69
Minimum Bill			\$4.50
<b>Total Bill for Billing Cycle</b>			<b>\$169.27</b>

# Example of Residential Bill

## Customer Segment

Rate: Customer on E1 Area T  
Coastal Climate Zone  
Customer size 10 to 25 MWh/year  
Generator size 5 to 10 MWh/year

Month	Without NEM		With NEM	
	Net Consumption (kWh)	Bill (\$)	Net Consumption (kWh)	Bill (\$)
January	850.2	\$195.03	782.5	\$169.27
February	641.1	\$123.70	474.7	\$71.56
March	546.0	\$86.55	248.4	\$28.69
April	421.8	\$55.93	38.7	\$4.50
May	444.9	\$68.69	73.4	\$8.52
June	491.1	\$82.29	132.3	\$15.28
July	524.3	\$90.58	97.3	\$11.24
August	375.5	\$50.60	0.0	\$4.50
September	326.3	\$39.27	0.0	\$4.50
October	366.1	\$48.13	61.9	\$4.50
November	458.6	\$65.55	279.8	\$23.07
December	639.3	\$114.70	522.0	\$80.29
<b>ANNUAL</b>	<b>6085.0</b>	<b>\$1,021.02</b>	<b>2711.0</b>	<b>\$425.93</b>

### Billing data output:

**Value of NEM (\$/year) =**  
 $\$1,021.02 - \$425.93 =$   
**\$595.09 \$/year**

**Net kWh exported (total kWh)**  
 $6,085 - 2,711 =$   
**3,374 kWh**

**Value of NEM (\$/kWh exported)**  
 $=$   
 $\$595.09 / 3,374\text{kWh} =$   
**\$0.18 \$/kWh**

\* Without NEM: User gets no credit for exported energy

# Example of Commercial Bill

## Customer Segment

Rate: Customer on A10S  
 Coastal Climate Zone  
 Customer size 25 to 50 MWh/year  
 Generator size 10 to 25 MWh/year

Month	Without NEM		With NEM	
	Net Consumption (kWh)	Bill (\$)	Net Consumption (kWh)	Bill (\$)
January	2605.4	\$433.44	2580.2	\$430.77
February	2033.7	\$372.83	1885.3	\$357.13
March	1949.7	\$358.69	1567.7	\$318.29
April	1851.4	\$347.37	1430.5	\$302.85
May	1722.2	\$425.13	1231.5	\$355.97
June	1630.8	\$409.46	1071.9	\$330.69
July	1719.3	\$418.90	1111.3	\$333.21
August	1723.7	\$417.74	1099.4	\$329.75
September	1701.8	\$418.29	1059.7	\$327.80
October	1950.7	\$456.09	1629.2	\$410.78
November	2095.3	\$375.76	1980.0	\$363.56
December	2372.1	\$409.18	2361.4	\$408.04
<b>ANNUAL</b>	<b>23356.2</b>	<b>\$4,842.87</b>	<b>19008.0</b>	<b>\$4,268.85</b>

### Billing data output:

**Value of NEM (\$/year) =**  
 $\$4,842.87 - \$4,268.85 =$   
**\$574.02 /year**

**Net kWh exported (total kWh)**  
 $23,356 - 19,008 =$   
**4,348 kWh**

**Value of NEM (\$/kWh exported) =**  
 $\$574.02 / 4,348 \text{ kWh} =$   
**\$0.13 /kWh**

\* Without NEM: User gets no credit for exported energy

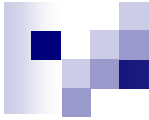


## 4. Utility Avoided Cost from NEM

- Using avoided cost methodology:

$$\text{Annual Value} = \sum (\text{Utility Value}_{\text{Hour}} (\$/\text{kWh}) * \text{kWh Exported}_{\text{Hour}})$$

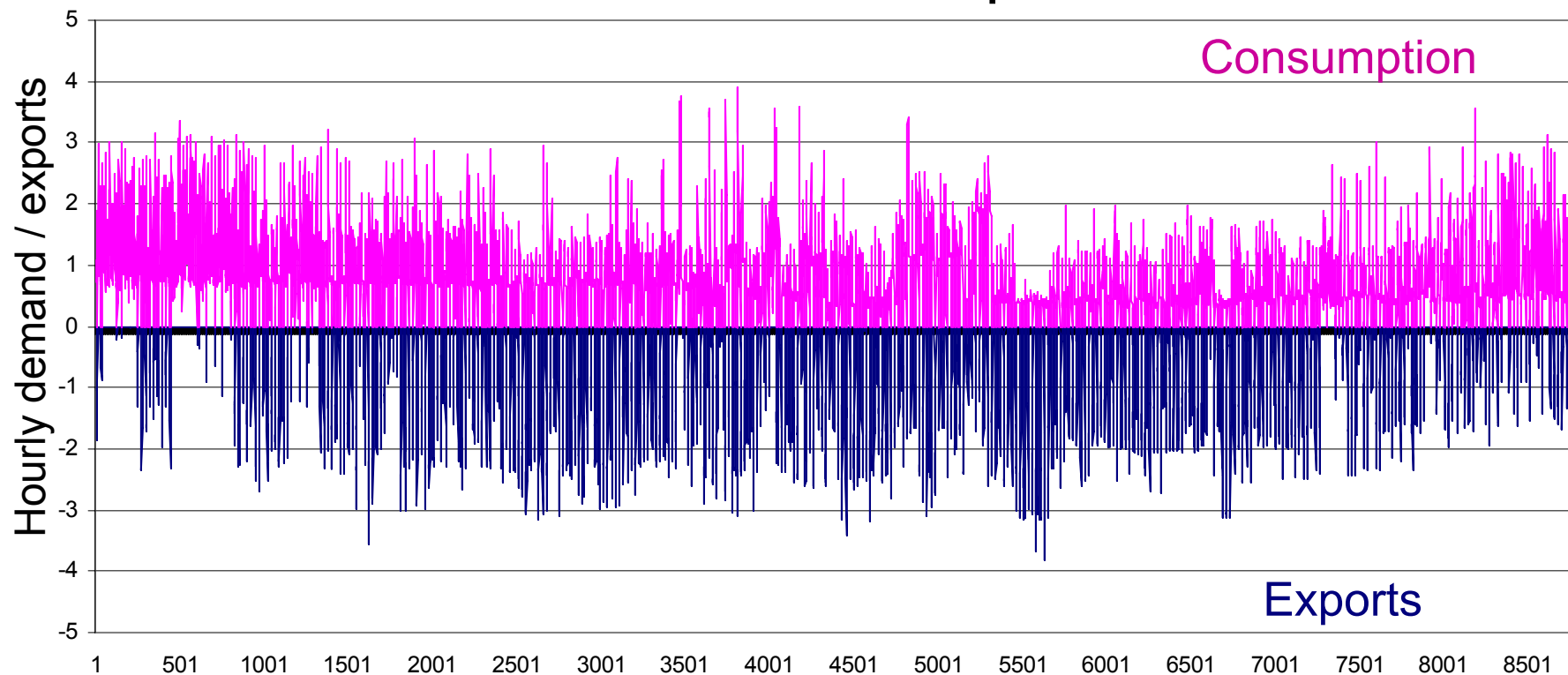
- Lifecycle value = NPV (Annual Values)
- Avoided cost values and export data are chronologically aligned
  - 2008 avoided costs for 2008 net kWh exported
- Data sources
  - 2008 market data, 2008 CAISO loads, 2008 PV output and exports
  - Methodology of avoided cost development



# Avoided cost of exported energy

Residential coastal example

Net Load Shape



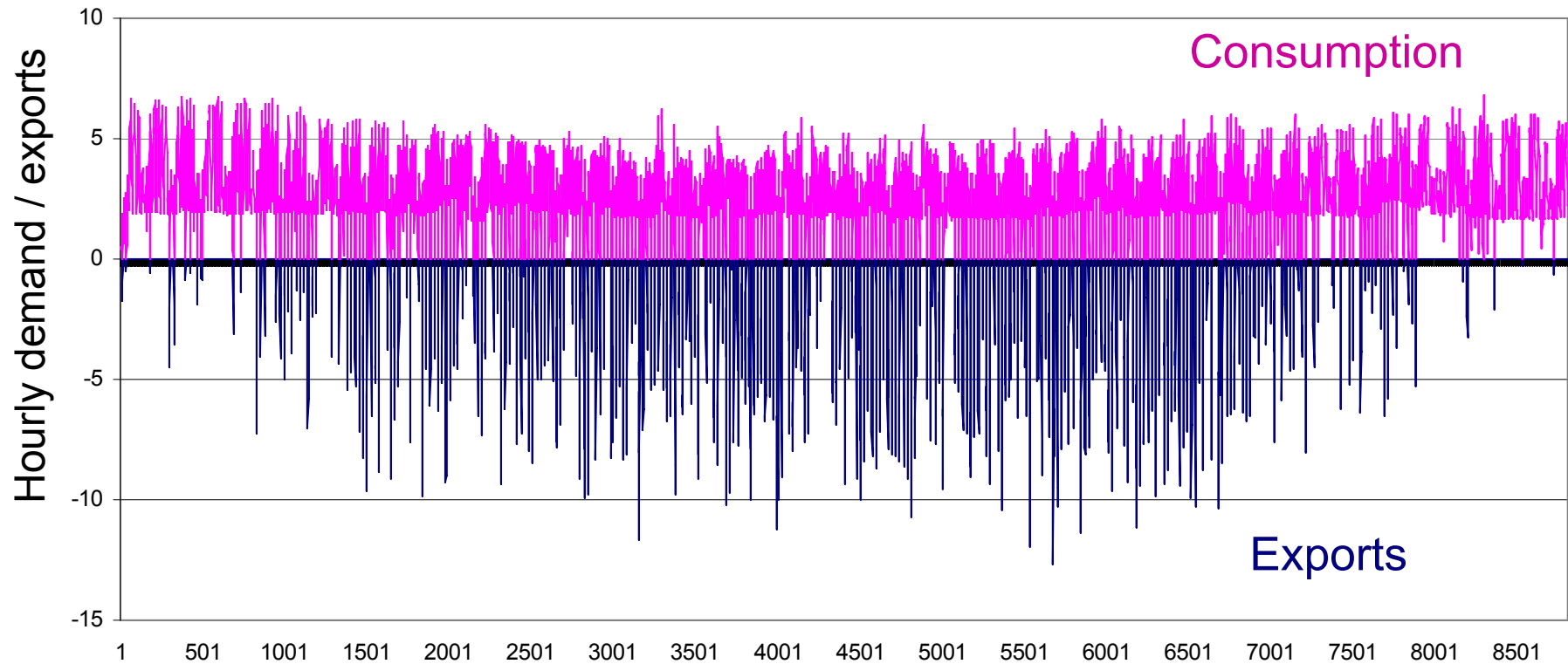
Levelized avoided cost of exports = \$0.1367



# Avoided cost of exported energy

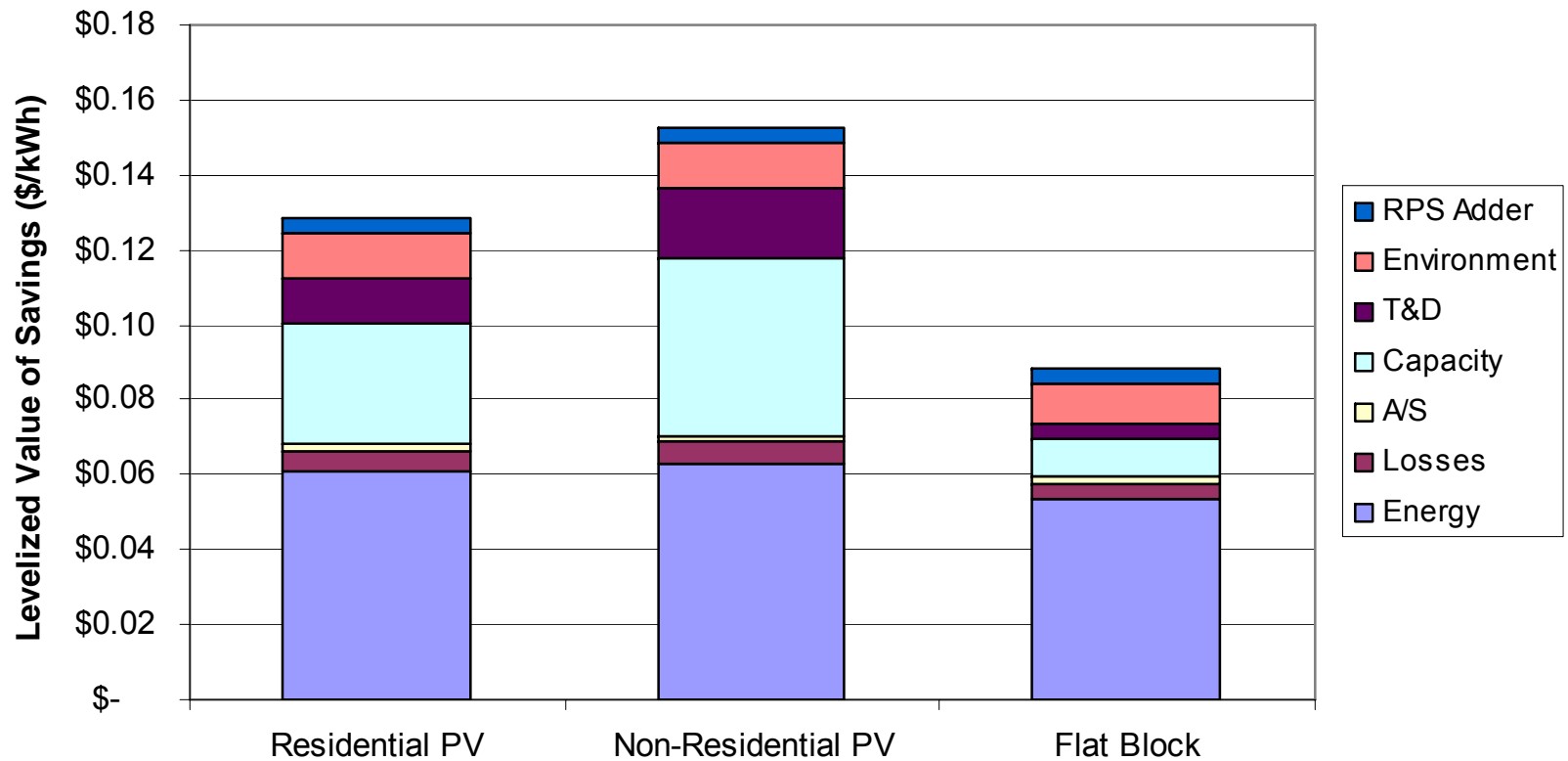
Non-residential coastal example

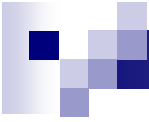
Net Load Shape



Levelized avoided cost of exports = \$0.1899

# Average Avoided Cost by Component for Two Sample PV Output Shapes (CZ3)





# 5. Net Cost of NEM by Rate Class

- Compute net cost of NEM by categories (rate, geographic area, install year) as
  - Net cost = utility cost of NEM – utility value of NEM
- Utility Value of NEM (by rate and total)

Number of Customers (Step 2)

	PV Output				
Gross Consumption					

Net Cost of NEM (\$/year) (Step 4)

	PV Output				
Gross Consumption					

\*

# Compute Total Net Cost

- Two examples in coastal region

Rate Class	<i>Avoided Cost</i>	<i>Change in Bill</i>	<b>Net Cost of NEM (\$/yr)</b>	Number of Customers in Segment	<b>Net Cost of NEM by Rate Class (\$/yr)</b>
	Utility Avoided Cost of NEM	Ratepayer Cost of NEM			
<b>Residential</b> Rate E1 Area T	<i>\$0.137/kWh</i> \$474.21	<i>\$0.176/kWh</i> \$595.02	<b>\$120.81</b>	1266	<b>\$152,945.46</b>
<b>Non- Residential</b> Schedule A-10	<i>\$0.190/kWh</i> \$658.78	<i>\$0.132/kWh</i> \$574.02	<b>-\$84.76</b>	26	<b>-\$2,203.76</b>

- Repeat across range of net load shapes and customer counts for each utility and climate zone



# Treatment of Excess Credits

- California Solar Surplus Act (AB920)
  - Ratemaking authority must adopt a “net surplus electricity compensation valuation” by 1/1/2011 for systems under 1MW
  - Eligible customer-generators can apply the net surplus valuation at the end of the 12-month period as payment or credit
  - Utility owns the REC for net surplus power
- Therefore, excess credits will get credited at avoided cost in the analysis assuming AB920 is implemented throughout the analysis horizon



# Treatment of Degradation and Rate Escalation over Analysis Horizon

## ■ Degradation

- For each customer profile, recompute an estimated 2020 net output production
- ITRON is evaluating the degradation factor

## ■ Retail Rate Escalation

- Retail rates are forecast to increase
- Use GHG Calculator average statewide rate increase estimate of 6.8% nominal per year (3.6% real)



# Next Steps

- Complete analysis using the process described, with any modifications
- Provide ‘analysis report’ to the CPUC for review – target is 1<sup>st</sup> week in December
- CPUC Energy Division staff will incorporate the ‘analysis report’ into the legislature report by 1/1/2010



# Preview of CSI C/E Analysis Approach



# CSI Report - Primary Research Questions

- How should we calculate cost-effectiveness for a market transformation program?
- What is the cost-effectiveness of CSI applications...
  - Installed in 2007 and 2008?
  - Projected to be installed through 2017?
- What additional metrics can we use to measure progress of CSI towards the program goals?

# Cost-effectiveness of CSI as a Market Transformation Program

- Program goal is to achieve a self-sustaining market by end of program (2017)
- Cost-effectiveness should track program progress and provide information for improvements
- Framework uses existing tests to show trajectory

Participant (PCT)

System payback and financials
Will customers continue to buy PV?

Program Administrator Cost Test (PAC)






Utility revenue requirement
How much is the ratepayer subsidy?

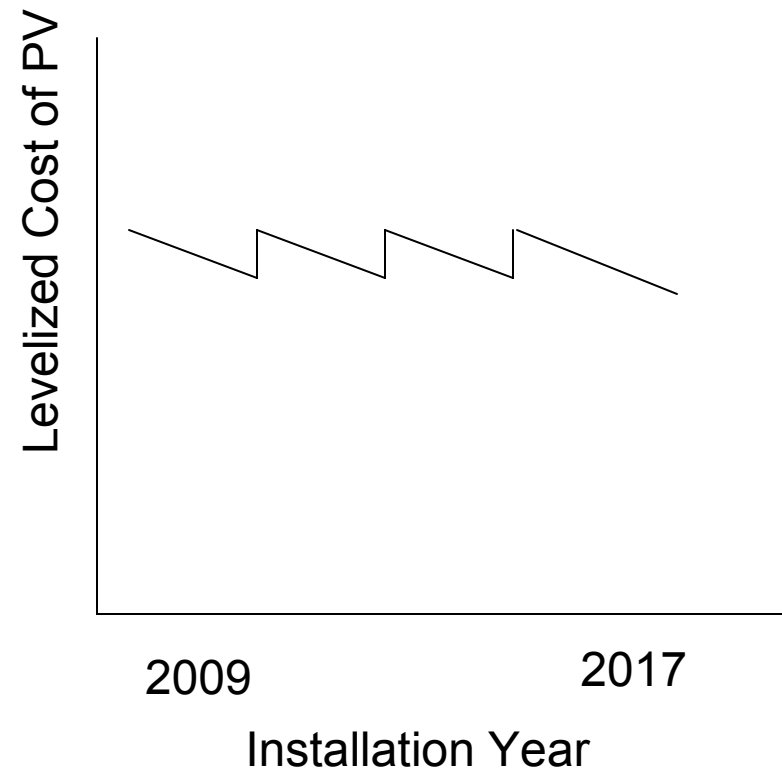
Total Resource Cost (TRC)

Overall CA Cost-effectiveness
Does PV provide a lower cost for CA?

# Drivers of future cost-effectiveness

Framework allows assessment of key drivers

-  ■ Customer bill savings
  - Rate increases improve economics
-  ■ PV system cost
  - Learning rates decrease costs
-  ■ Avoided cost projections
  - Utility avoided cost increases, RPS
-  ■ CSI tiers
  - CSI tiers decrease over time
-  ■ Federal tax credit
  - Federal tax credit expires in 2017



# Cost-Effectiveness Results

- Historical cost-effectiveness results show typical EM&V
- Forecasts capture market transformation effects
  - Scenarios of system cost reductions
    - Cost reduction path to hit payback level without incentives
    - Learning curve progress ratio

B/C Ratio Results

		Participant Cost Test PCT	Program Administrator Cost Test PAC	Total Resource Cost Test TRC
Historical	2007			
	2008			
	2009			
Forecast	2010			
	2011			
	2012			
	2013	Scenarios		
	2014			
	2015			
	2016			
	2017			
	2018			
	2019			
	2020			

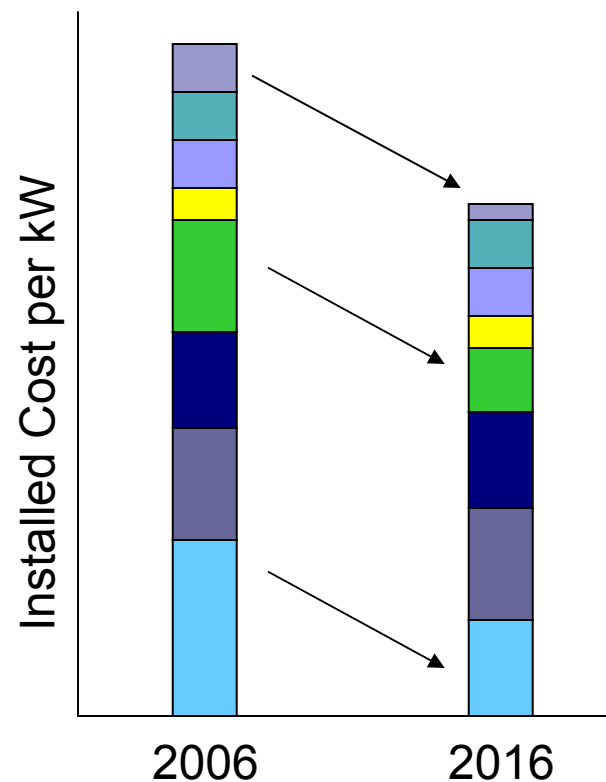
# Forecast System Cost by Component

## Bottom Up Analysis

- Break down the costs of each PV installation into a manageable number of cost elements

### PV Cost Components

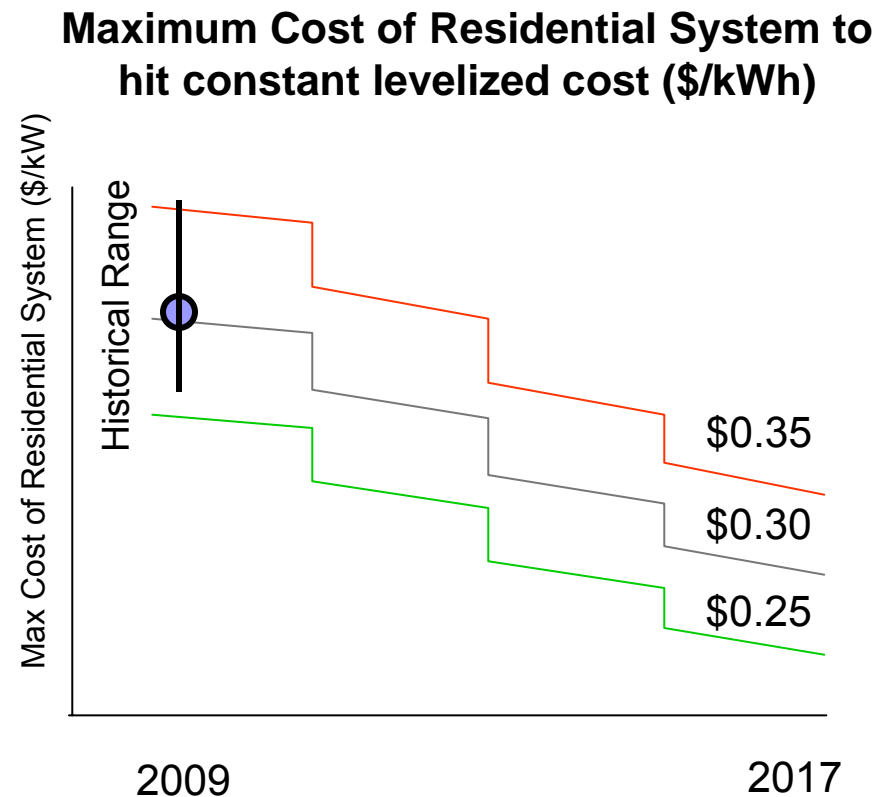
System Design  
Modules  
Inverter  
Balance of Plant  
Labor for Installation  
Maintenance  
Taxes & Insurance



# Cost Trajectory Forecast

## Top Down Analysis

- Cost trajectory shows required CA price points to hit cost levels
  - Levelized cost linked to customer adoption
- Provides metric to track program progress





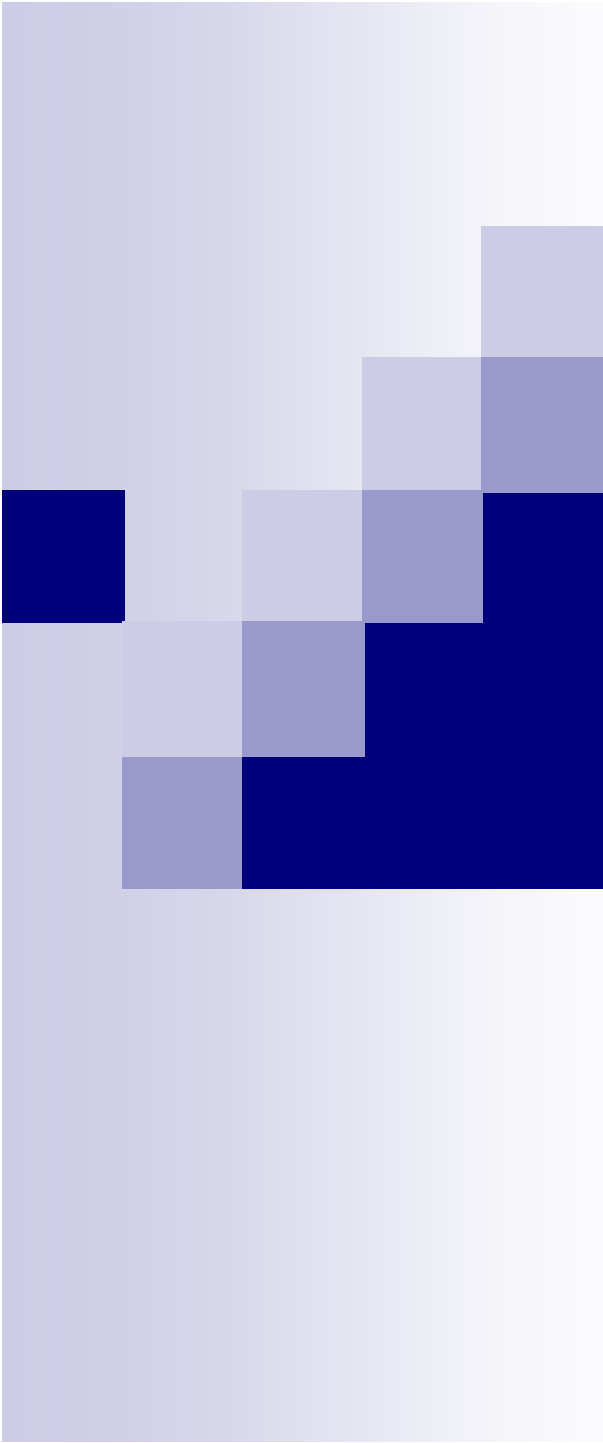
# Additional metrics to track progress?

- Number of installations in California
  - Progress toward capacity targets
  - Labor costs and efficiency
  - PV company health and labor force
- World-wide installations and manufacturing
  - California share of module purchases
  - California impact on learning curves for modules



# Analysis Tool

- Single installation cost-effectiveness spreadsheet for public use
  - Avoided cost estimation
  - System cost and levelized cost calculation
  - Customer bill impact (CPR) module
- Scenarios on key inputs, 'what if analysis'
  - System cost, learning rates, rate escalation, natural gas costs, RPS costs, others



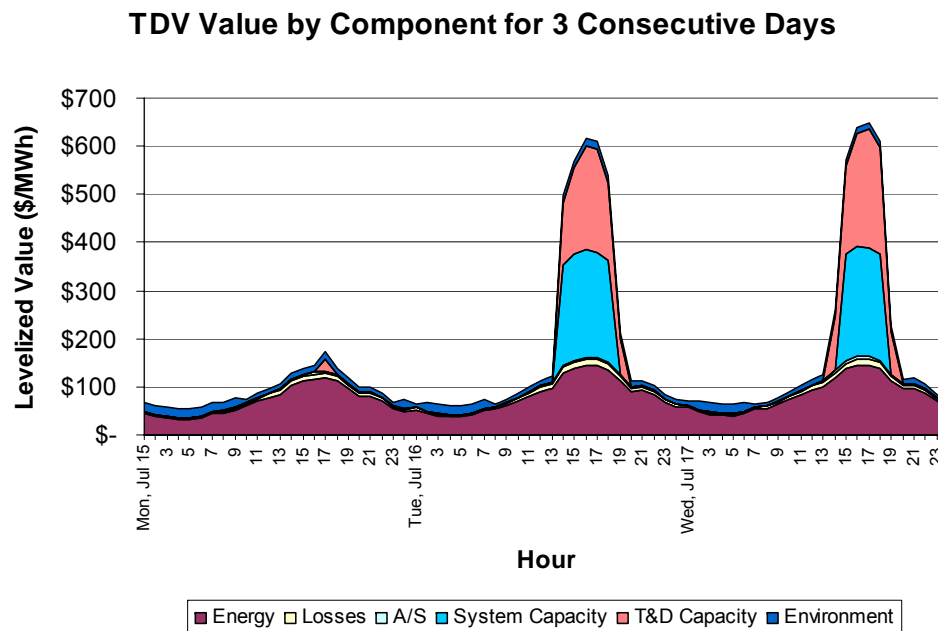
# Appendix: Additional Information on “Building Blocks”

# Building Blocks and Cost Tests

	Building block #1	Building block #2	Building block #3	
	Utility Avoided Cost	Financial Pro-Forma (System Cost less Federal Tax incentive)	Bill Change	Utility ratepayer Incentive
TRC	<b>Benefit</b>	<b>Cost</b>	Not included	Not included
PAC	<b>Benefit</b>	Not included	Not included	<b>Cost</b>
PCT	Not included	<b>Cost</b>	<b>Benefit</b>	<b>Benefit</b>
RIM	<b>Benefit</b>	Not included	<b>Cost</b>	<b>Cost</b>

# 1. Utility Avoided Cost

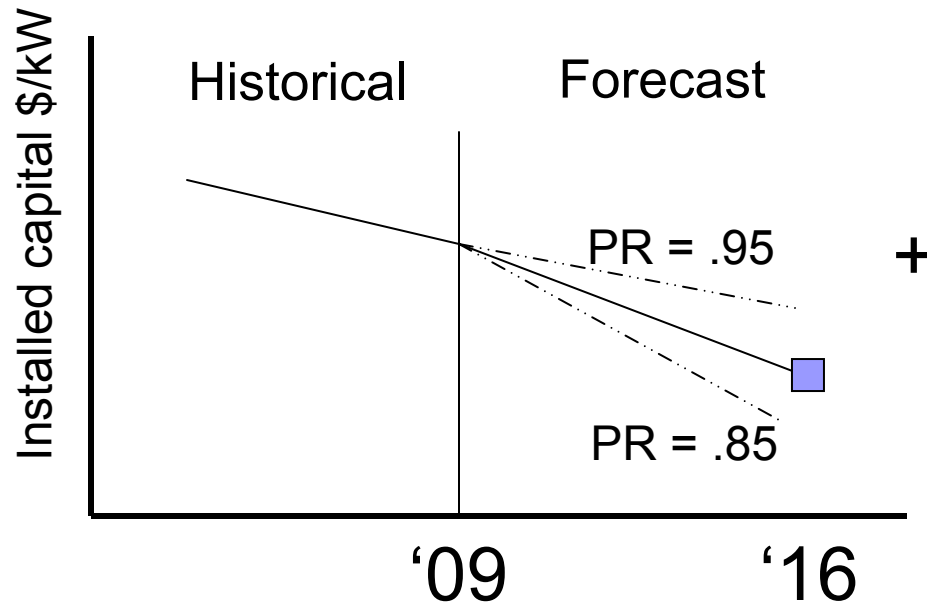
Conforms to DG Cost-Effectiveness Decision D.09-08-026



- Publicly available data
- Non-proprietary spreadsheet tool
- Suitable for valuation of range of resources
  - Non-dispatchable
  - Dispatchable
  - Energy Storage

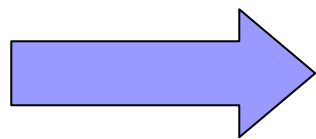
## 2. PV System Costs

### ■ Installed PV cost

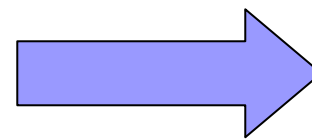


### ■ Other Inputs

- Fed Tax credits
- CSI incentives
- Financing rates
- REC value
- Maintenance cost
- System life and degradation



Public Pro-forma  
Analysis Tool



Levelized  
System Cost



# 3. Customer Bill Savings

- Clean Power
  - Research product
- Input
  - Rate classification
  - Interval net load data
- Outputs
  - Billing determinants
  - Monthly bills
- Utilities
  - PG&E
  - SCE
  - SDG&E
- Rates
  - Res
  - Sm. Com
  - Lg. Com
  - Industrial



# PV Financial Pro- forma

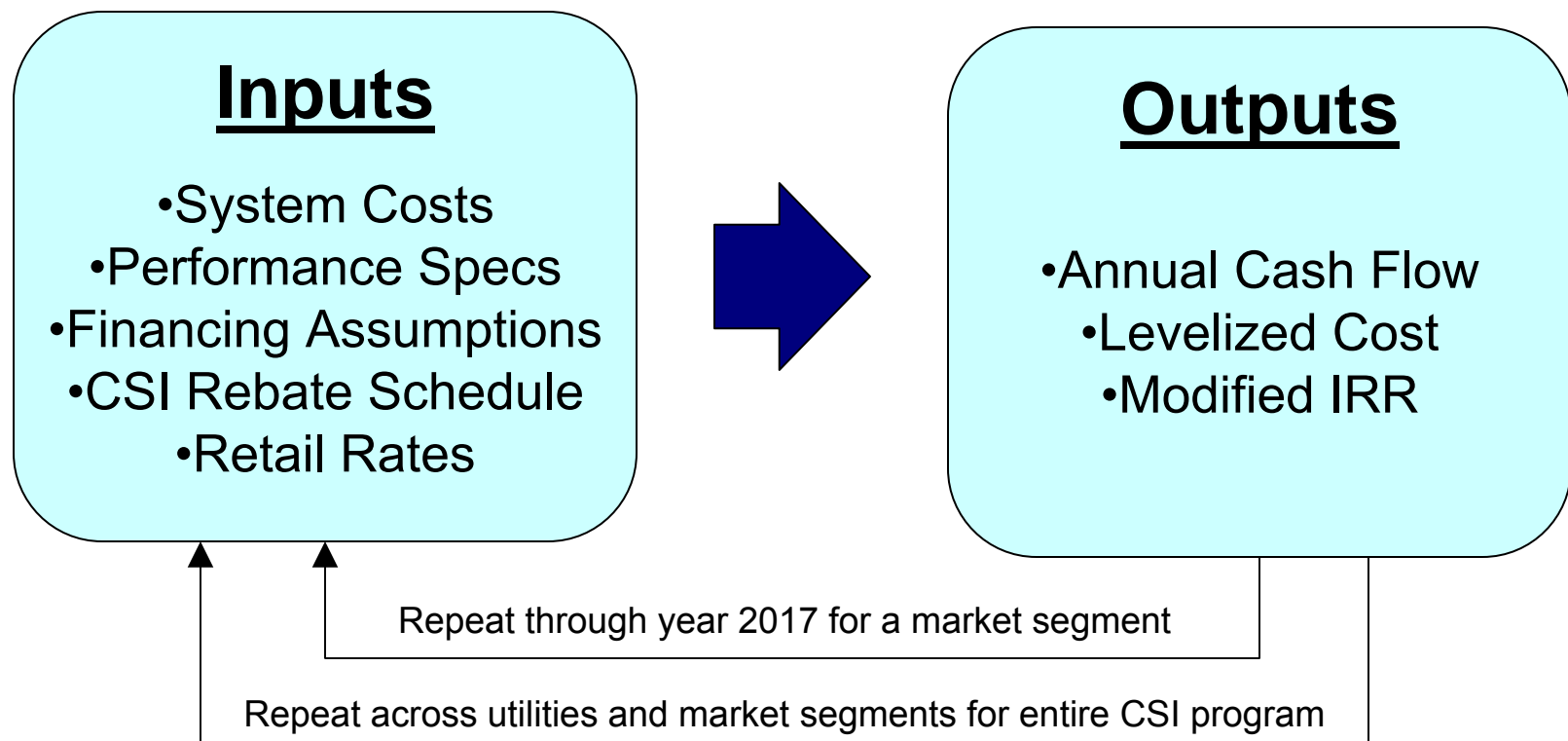
# Outline

- Background
- Input Assumptions
  - System Cost Assumptions
  - Financing Options
  - CSI Rebate Schedule
- Model Walkthrough
  - Specific Project
    - Maximizing Project Leverage
  - Market Segment
    - Constant Levelized Cost Graph
  - CSI Program
- Informal Review



# Background

- Calculates levelized cost based on inputs
- Non-proprietary, public, open source tool.



# Input Assumptions

- Vary by utility, type, size, and financing choice
- Example input block:

Residential Inputs		Utility: SCE	Financing: Home Equity Loan										Size: <10kW		
	P.R. ↓	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
<b>System Price</b>															
Module Price (\$/W)	80%	\$ 3.85	\$ 3.81	\$ 3.56	\$ 3.32	\$ 3.10	\$ 2.89	\$ 2.69	\$ 2.51	\$ 2.35	\$ 2.19	\$ 2.04	\$ 1.91	\$ 1.78	\$ 1.66
Inverter Price (\$/W)		\$ 1.01	\$ 0.89	\$ 0.85	\$ 0.80	\$ 0.76	\$ 0.72	\$ 0.69	\$ 0.65	\$ 0.62	\$ 0.59	\$ 0.56	\$ 0.53	\$ 0.51	\$ 0.48
Other Costs (\$/W)		\$ 3.02	\$ 3.59	\$ 3.41	\$ 3.24	\$ 3.08	\$ 2.92	\$ 2.78	\$ 2.64	\$ 2.51	\$ 2.38	\$ 2.26	\$ 2.15	\$ 2.04	\$ 1.94
System Cost per Watt		\$ 7.88	\$ 8.29	\$ 7.81	\$ 7.36	\$ 6.94	\$ 6.54	\$ 6.16	\$ 5.81	\$ 5.47	\$ 5.16	\$ 4.87	\$ 4.59	\$ 4.33	\$ 4.08
<b>Performance Inputs</b>															
	Escalator														
Overall derate factor	0%	0.8	0.8	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
Annual Net Capacity Factor	1%	22%	22%	22%	22%	23%	23%	23%	23%	24%	24%	24%	24%	25%	25%
System lifetime (Years)	0%	25	25	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
Degradation Factor (%/yr)	0%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
DC to AC derate factor	0%	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
<b>Cost Inputs</b>															
O&M Costs (\$/kW)	-2%	\$ 25.00	\$ 25.00	\$ 24.50	\$ 24.01	\$ 23.53	\$ 23.06	\$ 22.60	\$ 22.15	\$ 21.70	\$ 21.27	\$ 20.84	\$ 20.43	\$ 20.02	\$ 19.62
O&M Cost Escalator (%/yr)	0%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Inverter replacement costs (\$/W)	-2%	\$ 0.60	\$ 0.60	\$ 0.59	\$ 0.58	\$ 0.56	\$ 0.55	\$ 0.54	\$ 0.53	\$ 0.52	\$ 0.51	\$ 0.50	\$ 0.49	\$ 0.48	\$ 0.47
Inverter replacement time (Years)	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Insurance Expense (\$/kW)	0%	\$ 20.00	\$ 20.00	\$ 20.00	\$ 20.00	\$ 20.00	\$ 20.00	\$ 20.00	\$ 20.00	\$ 20.00	\$ 20.00	\$ 20.00	\$ 20.00	\$ 20.00	\$ 20.00
Insurance Escalator (%/yr)	0%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
REC price (\$/W)	0%	\$ 0.015	\$ 0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
REC price escalator (%/yr)	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
<b>Finance Inputs</b>															
Federal Tax Rate		35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
State Tax Rate		9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%
Tax Credit Rate		30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	0%	0%	0%
Percent financed with Equity		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Debt Interest Rate		8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Target DSCR		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Years of Debt Service in DSRF		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Period in Years		20	20	20	20	20	20	20	20	20	20	20	20	20	20
WACC		8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Cost of Equity		8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Finance rate		8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Reinvestment rate		8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Retail rate (\$/W)		\$ 0.18	\$ 0.18	\$ 0.18	\$ 0.19	\$ 0.19	\$ 0.19	\$ 0.20	\$ 0.20	\$ 0.21	\$ 0.21	\$ 0.22	\$ 0.22	\$ 0.22	\$ 0.23
PBI Avg Rebate Amount (\$/W)		\$ 0.390	\$ 0.352	\$ 0.334	\$ 0.260	\$ 0.260	\$ 0.223	\$ 0.199	\$ 0.150	\$ 0.092	\$ 0.065	\$ 0.032	\$ -	\$ -	\$ -
EPBB Avg Rebate amount (\$/W)		\$ 2.500	\$ 2.272	\$ 2.177	\$ 1.900	\$ 1.900	\$ 1.579	\$ 1.415	\$ 1.100	\$ 0.667	\$ 0.385	\$ 0.257	\$ -	\$ -	\$ -

# System Cost Assumptions

- Actual CSI data for 2007 and 2008
- Forecast until 2020 uses PV module learning curves with different progress ratios

## Module Prices

Cumulative global capacity (MW)		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
Growth of:		24%	9,612	14,730	18265	22649	28085	34825	43183	53547	66398	82333	102093	126596	156979	194654

Module prices (\$/W)		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
<10kW	Progress Ratios:	70%	\$ 3.85	\$ 3.81	3.411	3.053	2.733	2.447	2.191	1.961	1.756	1.572	1.407	1.260	1.128	1.009
		80%	\$ 3.85	\$ 3.81	3.555	3.317	3.095	2.888	2.695	2.515	2.346	2.189	2.043	1.906	1.779	1.660
		90%	\$ 3.85	\$ 3.81	3.687	3.569	3.454	3.343	3.235	3.131	3.031	2.933	2.839	2.747	2.659	2.573
10-100kW	Progress Ratios:	70%	\$ 2.97	\$ 2.89	2.587	2.316	2.073	1.856	1.662	1.488	1.332	1.192	1.067	0.955	0.855	0.766
		80%	\$ 2.97	\$ 2.89	2.697	2.516	2.348	2.191	2.044	1.907	1.780	1.661	1.550	1.446	1.349	1.259
		90%	\$ 2.97	\$ 2.89	2.797	2.707	2.620	2.536	2.454	2.375	2.299	2.225	2.153	2.084	2.017	1.952
100-500kW	Progress Ratios:	70%	\$ 2.25	\$ 2.44	2.184	1.955	1.751	1.567	1.403	1.256	1.124	1.006	0.901	0.807	0.722	0.646
		80%	\$ 2.25	\$ 2.44	2.277	2.124	1.982	1.850	1.726	1.610	1.503	1.402	1.308	1.221	1.139	1.063
		90%	\$ 2.25	\$ 2.44	2.362	2.286	2.212	2.141	2.072	2.005	1.941	1.878	1.818	1.759	1.703	1.648
>=500kW	Progress Ratios:	70%	\$ 2.19	\$ 2.44	2.184	1.955	1.751	1.567	1.403	1.256	1.124	1.006	0.901	0.807	0.722	0.646
		80%	\$ 2.19	\$ 2.44	2.277	2.124	1.982	1.850	1.726	1.610	1.503	1.402	1.308	1.221	1.139	1.063
		90%	\$ 2.19	\$ 2.44	2.362	2.286	2.212	2.141	2.072	2.005	1.941	1.878	1.818	1.759	1.703	1.648

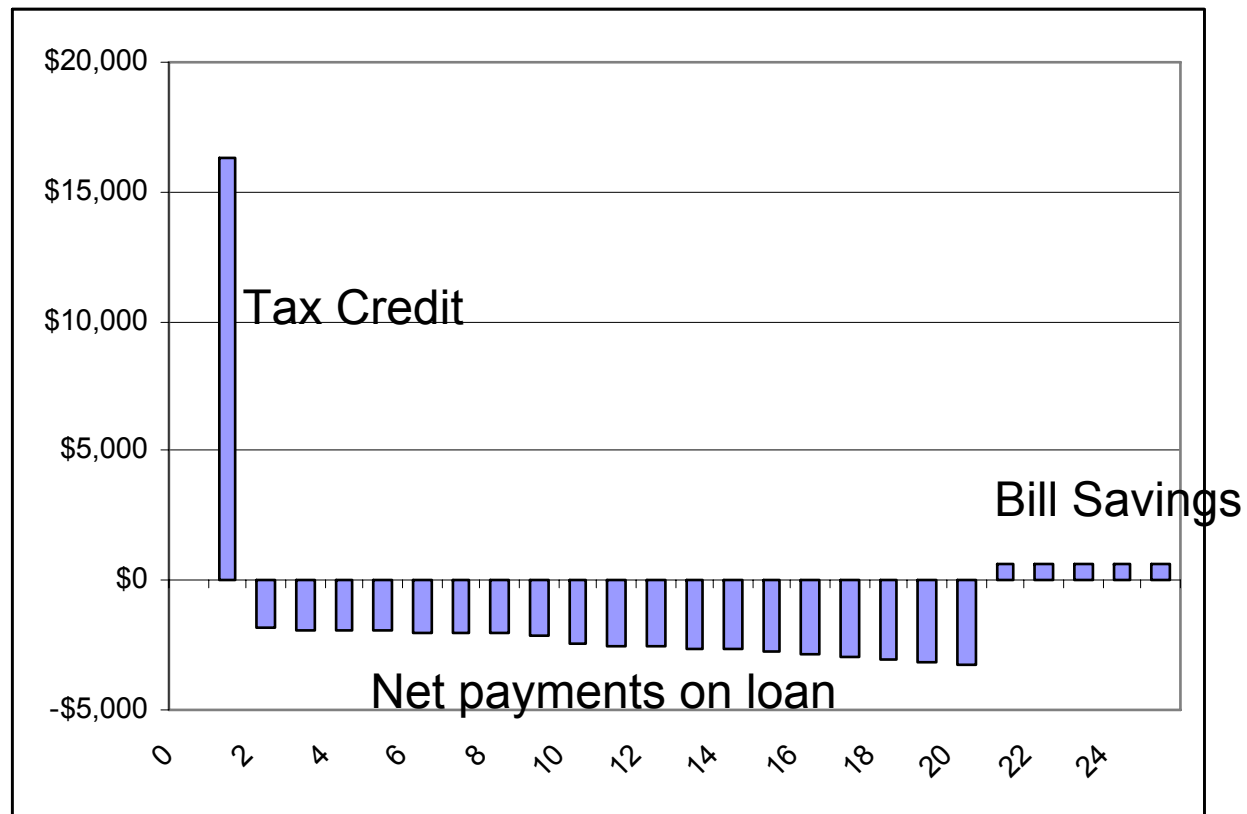
# Financing Assumptions

- Different financing options allowed:
  - Cash, Home Equity Loan, PPA / Commercial, Government Financing, and Non-Profit Financing
- For the PPA/Commercial financing option:
  - Model maximizes leverage based on the 'Target Debt Service Coverage Ratio' input
- Example of finance assumption:

Home Equity Loan	Override	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Federal Tax Rate	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
State Tax Rate	8.84%	8.84%	8.84%	8.84%	8.84%	8.84%	8.84%	8.84%	8.84%	8.84%	8.84%	8.84%	8.84%	8.84%	8.84%
Tax Credit Rate	-	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	0%	0%	0%	0%
Percent financed with Equity	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Debt Interest Rate	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
Target DSCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Years of Debt Service in DSRF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Period in Years	20.00	20	20	20	20	20	20	20	20	20	20	20	20	20	20
WACC	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Cost of Equity	8%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
Finance rate		8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Reinvestment rate		8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%

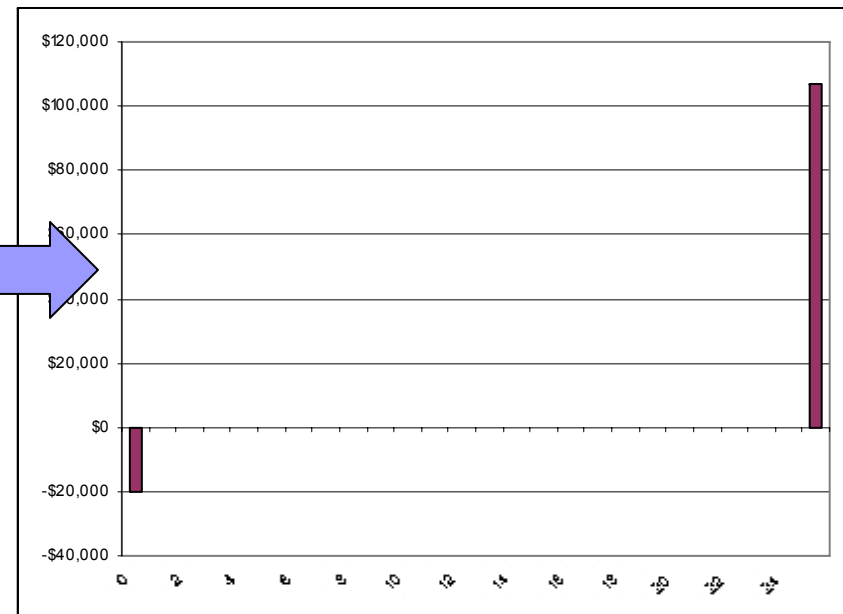
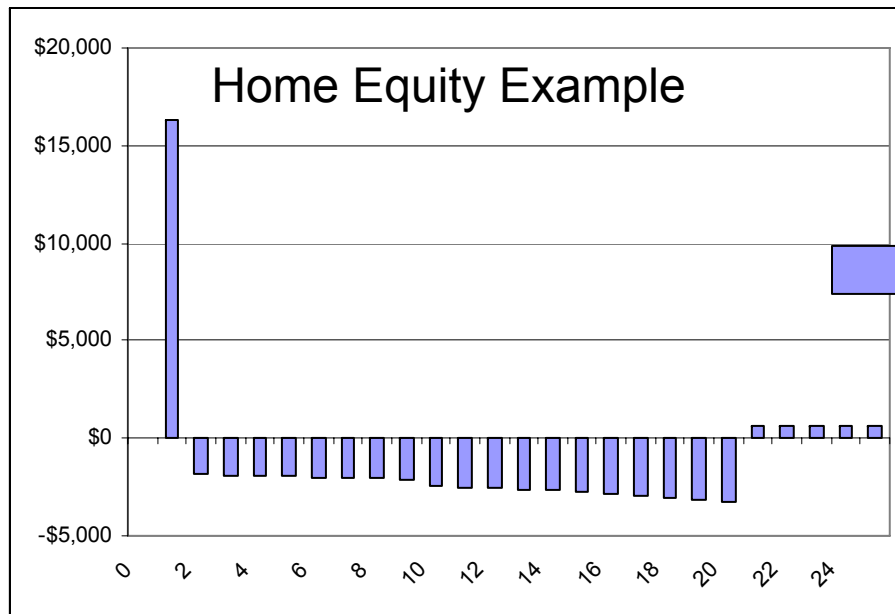
# Home Equity Loan Example

Home Equity Cash Flows



# Modified IRR Metric

- Modified IRR converts cash flow to initial investment and final return
  - Negative cash flows incur a finance cost
  - Positive cash flows earn a reinvestment value
- Modified IRR is then the discount rate that results in NPV \$0



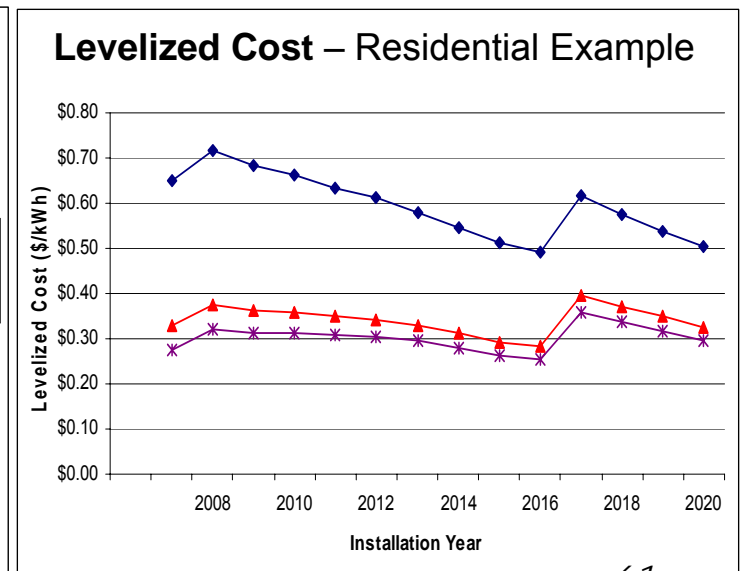
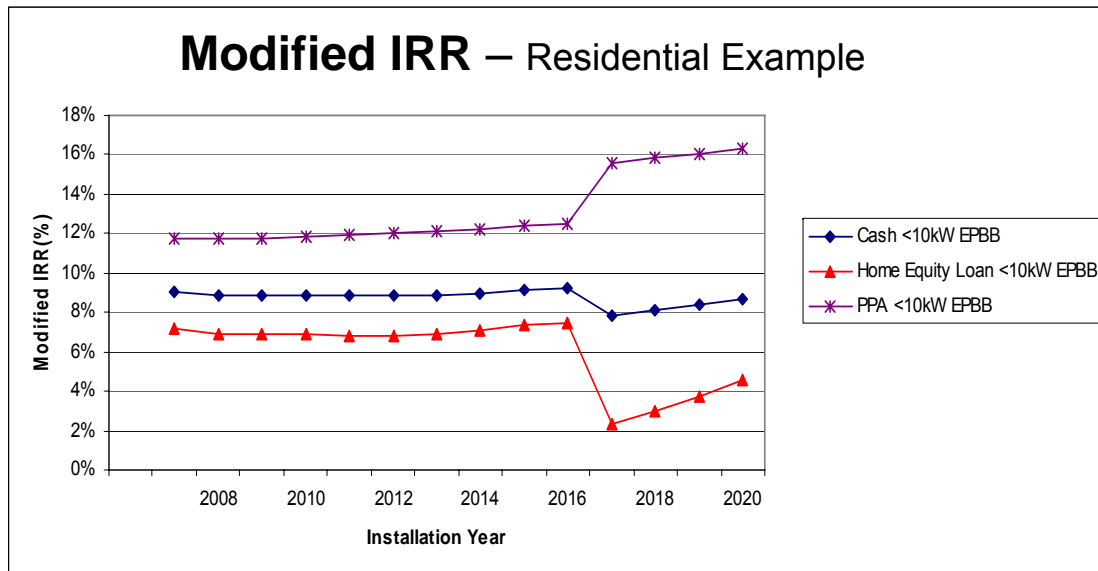
# Inputs to Modified IRR

- Assumption on financing cost and reinvestment value changes by financing structure

Financing Type	Cash	Home Equity	PPA/Commercial	Government	Non-profit
	Finance cost of cash and reinvestment rate assumed to be low, on the order to T-bills.	Assumed that home equity loan is used as revolving credit, cash surplus is used to pay off loan, cash withdraws come from loan	Finance cost is equal to WACC, reinvestment rate set equal to the equity return	For municipal bond financed projects, finance cost equal debt cost, cash outflows used to pay off bond	Finance cost is equal to WACC, reinvestment rate set equal to equity return
Finance rate	3%	8%	10.56%	4%	10.56%
Reinvest rate	3%	8%	11.56%	4%	14.40%
Percentage Equity	100%	0%	Minimized	0%	40%
WACC	10.56%	8%	10.56%	4%	10.56%
Cost of Equity	10.56%	8%	Based on % equity	4%	14.40%
Debt Interest Rate	-	8%	8%	4%	8%
Federal tax rate	35%	35%	35%	-	-
State tax rate	8.84%	8.84%	8.84%	-	-
Federal tax credit	30%	30%	30%	-	-

# Example Results for Residential Sector

- PPA has best modified IRR result, primarily because of depreciation tax savings
- Cash is the worst outcome
- Federal ITC has large impact on home equity because it helps repay loan early



# CSI Rebate Schedule Assumptions

- Uses percentage adoption numbers and CSI target capacity per incentive step to forecast incentive step in the beginning of each year.

## Incentive Step at Beginning of Year

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PG&E	Residential	2	3	5	5	6	7	8	9	10					
	Non Residential	2	5	5	6	6	7	8	10						
		2	5	5	6	6	7	8	10						
SCE	Residential	2	2	3	4	4	4	5	6	6	7	8			
	Non Residential	2	4	4	5	5	6	7	8	9	10				
		2	4	4	5	5	6	7	8	9	10				
CCSE	Residential	2	3	4	4	5	5	6	7	8	9	10			
	Non Residential	2	4	5	5	6	7	8	9	10					
		2	4	5	5	6	7	8	9	10					

## Total MW Allocated in CSI Program (MW)

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PG&E	Residential	22.0	30.1	15.6	20.3	26.4	34.3	44.6	58.0	4.1	0.0	0.0	0.0	0.0	0.0
	Non Residential	84.0	34.0	35.4	46.0	59.8	77.8	101.1	87.4	0.0	0.0	0.0	0.0	0.0	0.0
SCE	Residential	7.3	12.9	6.1	7.9	10.2	13.3	17.3	22.5	29.3	38.0	49.4	0.0	0.0	0.0
	Non Residential	74.8	0.5	22.6	29.4	38.2	49.6	64.5	83.9	109.0	69.2	0.0	0.0	0.0	0.0
CCSE	Residential	2.5	4.5	2.1	2.7	3.5	4.6	6.0	7.8	10.1	13.2	2.4	0.0	0.0	0.0
	Non Residential	18.0	7.3	7.6	9.9	12.8	16.7	21.7	28.2	4.8	0.0	0.0	0.0	0.0	0.0
Annual MW allocation		208.6	89.3	89.4	116.2	151.0	196.3	255.2	287.8	157.3	120.4	51.8	0.0	0.0	0.0

# Specific Project Walkthrough

Use Dropdown Menus for:

- Utility: PG&E, SCE, CCSE
- Module type:
  - Residential
  - Commercial
  - Government/Non-Profit
- System Size Range:
  - <10kW
  - 10-100kW
  - 100-500kW
  - >500kW
- Type of Rebate:
  - EPBB
  - PBI
- Financing Choice

Inputs	Choose Project:
Utility	PG&E ▼
Type of Module	Residential ▼
System Size Range	<10kW ▼
Type of rebate	EPBB ▼
Financing Choice	PPA/Commercial ▼
PV Module Progress Ratio	80% ▼
Default year	2009 ▼

# Specific Project Inputs

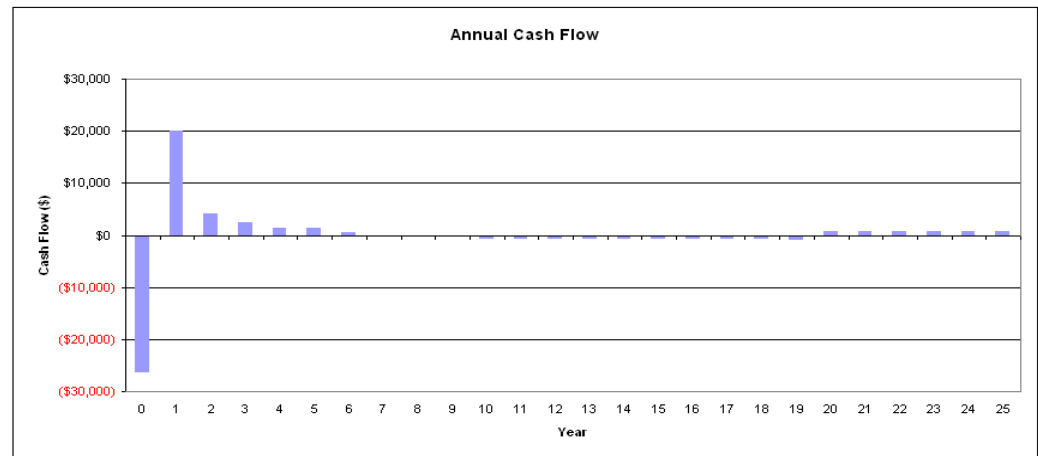
	Default	Override
<b>System Size (kW)</b>	5	
<b>System Price</b>		
Module Price (\$/W)	\$3.555	
Inverter Price (\$/W)	\$0.846	
Other Costs (\$/W)	\$3.411	
<i>System Cost per Watt</i>	\$7.811	
<b>System Design</b>		
Overall derate factor	0.80	
Annual Net Capacity Factor	22.2%	
System Lifetime (Years)	25	
Degradation Factor (%/yr)	0.50%	
DC to AC derate factor	0.90	
<b>Other Costs</b>		
O&M Costs (\$/kW)	\$24.500	
O&M Cost Escalator (%/yr)	2.50%	
Inverter replacement costs (\$/W)	\$0.588	
Inverter replacement time (Years)	10	
Insurance Expense (\$/kW)	\$20.000	
Insurance Escalator (%/yr)	2.50%	
REC price (\$/W)	\$0.015	
REC price escalator (%/yr)	0.00%	
<b>Finance Inputs</b>		
Federal Tax Rate	35.00%	
State Tax Rate	8.84%	
Tax Credit Rate	30.00%	
Percent Financed with Equity	63%	63%
Debt Interest Rate	8.00%	
Target DSCR	1.50	
Years of Debt Service in DSRF	1.00	
Debt Period in Years	20.00	
WACC	10.56%	
Cost of Equity	12.04%	
Finance Rate	10.56%	
Reinvestment Rate	12.04%	
Retail rate (\$/W)	\$0.184	
Rate Escalator	2.00%	
<b>CSI Rebate</b>		
PBI Avg Rebate Amount (\$/W)	\$0.334	
EPBB Avg Rebate amount (\$/W)	\$2.177	

- Default inputs are selected based on project type.
- To override default inputs, type desired value in the 'Override' column.

# Specific Project Outputs

- Outputs:
  - Annual cash flow
  - Levelized cost
  - Modified IRR

Outputs	
Levelized Cost (\$/W)	\$0.2766
Modified IRR (%)	11.79%



# Maximizing Project Leverage

- For PPA/Commercial financing option:
  - If output cells turn red, use the 'Max Leverage' button to maximize leverage:

Inputs	
Choose Project:	
Utility	PG&E
Type of Module	Residential
System Size Range	<10KW
Type of rebate	EPBB
Financing Choice	PPA/Commercial
PV Module Progress Ratio	80%
Default year	2009

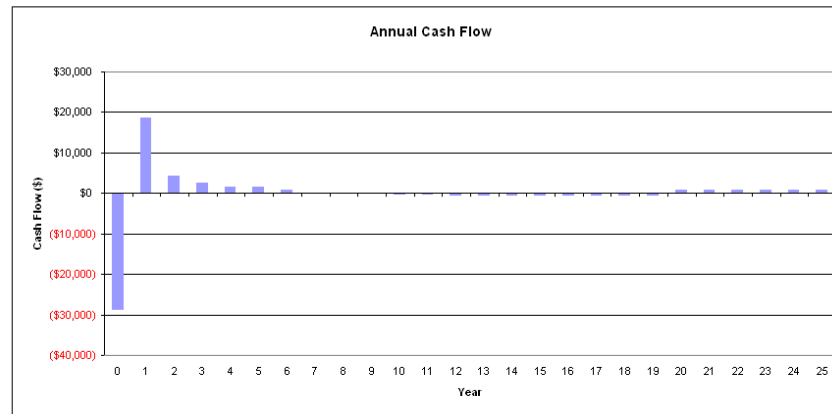
	Default	Override
<b>System Size (kW)</b>	5	
<b>System Price</b>		
Module Price (\$/W)	\$3.555	
Inverter Price (\$/W)	\$0.846	
Other Costs (\$/W)	\$3.411	
<i>System Cost per Watt</i>		
	\$7.811	
<b>System Design</b>		
Overall derate factor	0.80	
Annual Net Capacity Factor	22.2%	
System Lifetime (Years)	25	
Degradation Factor (%/yr)	0.50%	
DC to AC derate factor	0.90	
<b>Other Costs</b>		
O&M Costs (\$/kW)	\$24.500	
O&M Cost Escalator (%/yr)	2.50%	
Inverter replacement costs (\$/W)	\$0.588	
Inverter replacement time (Years)	10	
Insurance Expense (\$/kW)	\$20.000	
Insurance Escalator (%/yr)	2.50%	
REC price (\$/W)	\$0.015	
REC price escalator (%/yr)	0.00%	
<b>Finance Inputs</b>		
Federal Tax Rate	35.00%	
State Tax Rate	8.84%	
Tax Credit Rate	30.00%	
Percent Financed with Equity	70%	

Outputs	
Levelized Cost (\$/W)	\$0.3406
Modified IRR (%)	11.18%

For PPA/Commercial, if RED, use button to maximize leverage:

Max Leverage

For max leverage Op Profit=DS*coverage ratio	
Operating Profit	62,713
Operating Profit- DS*coverage ratio	14,975



# Maximizing Project Leverage

- A macro minimizes the % Financed with Equity so that the operating profit = debt service \* coverage ratio

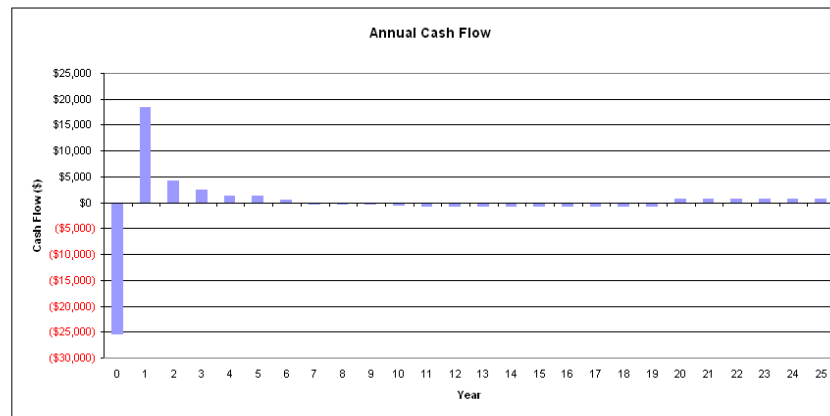
Inputs	
Choose Project:	
Utility	PGE
Type of Module	Residential
System Size Range	<10KW
Type of rebate	EPBB
Financing Choice	PPA/Commercial
PV Module Progress Ratio	80%
Default year	2009

Outputs	
Levelized Cost (\$/W)	\$0.3124
Modified IRR (%)	11.78%

For PPA/Commercial: If RED, use button to maximize leverage:

Max Leverage
--------------

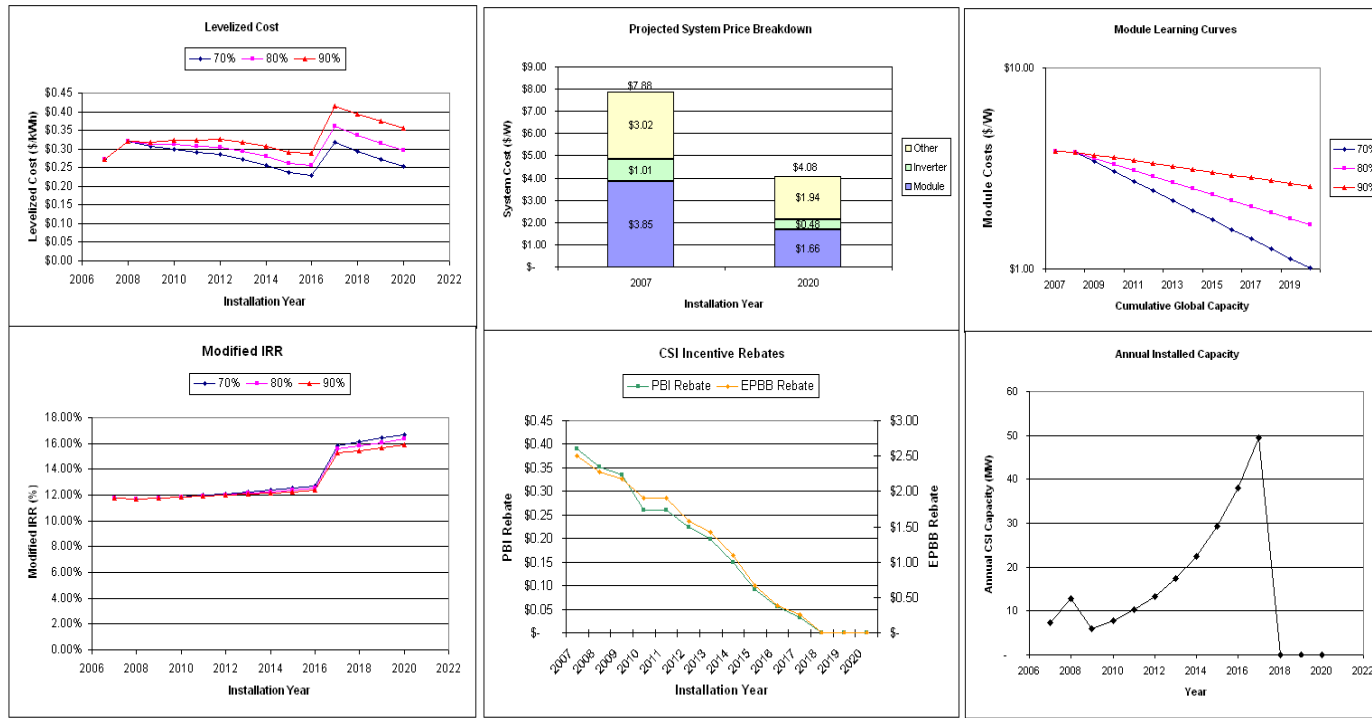
	Default	Override
<b>System Size (kW)</b>	5	
<b>System Price</b>		
Module Price (\$/W)	\$3.555	
Inverter Price (\$/W)	\$0.846	
Other Costs (\$/W)	\$3.411	
<i>System Cost per Watt</i>	<i>\$7.811</i>	
<b>System Design</b>		
Overall derate factor	0.80	
Annual Net Capacity Factor	22.2%	
System Lifetime (Years)	25	
Degradation Factor (%/yr)	0.50%	
DC to AC derate factor	0.90	
<b>Other Costs</b>		
O&M Costs (\$/kW)	\$24.500	
O&M Cost Escalator (%/yr)	2.50%	
Inverter replacement costs (\$/W)	\$0.588	
Inverter replacement time (Years)	10	
Insurance Expense (\$/kW)	\$20.000	
Insurance Escalator (%/yr)	2.50%	
REC price (\$/W)	\$0.015	
REC price escalator (%/yr)	0.00%	
<b>Finance Inputs</b>		
Federal Tax Rate	35.00%	
State Tax Rate	8.84%	
Tax Credit Rate	30.00%	
Percent Financed with Equity	61%	61%



# Market Segment Walkthrough

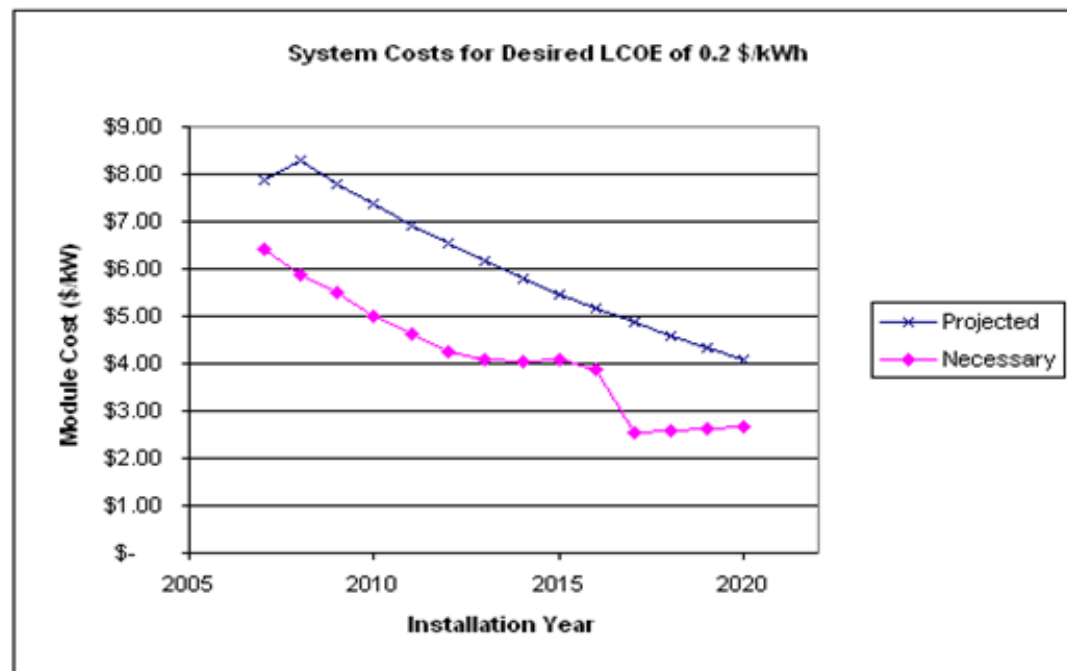
- Choose a market segment:
- Run model and obtain results:

SCE	▼
Residential	▼
<10kW	▼
EPBB	▼
PPA/Commercial	▼



# Constant Levelized Cost Graph

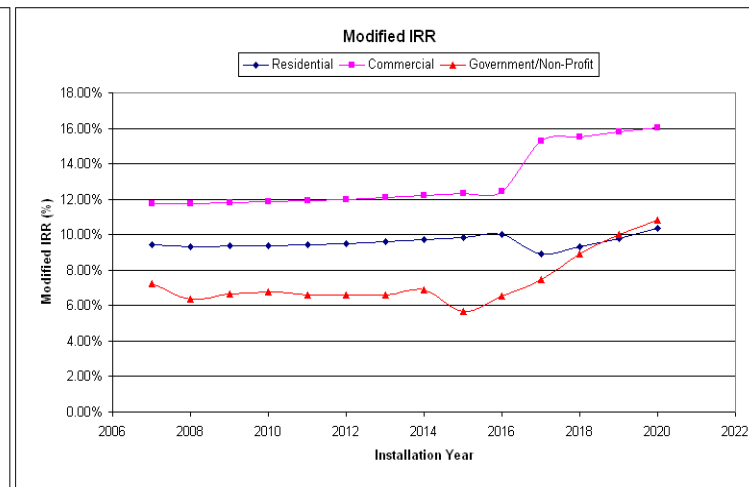
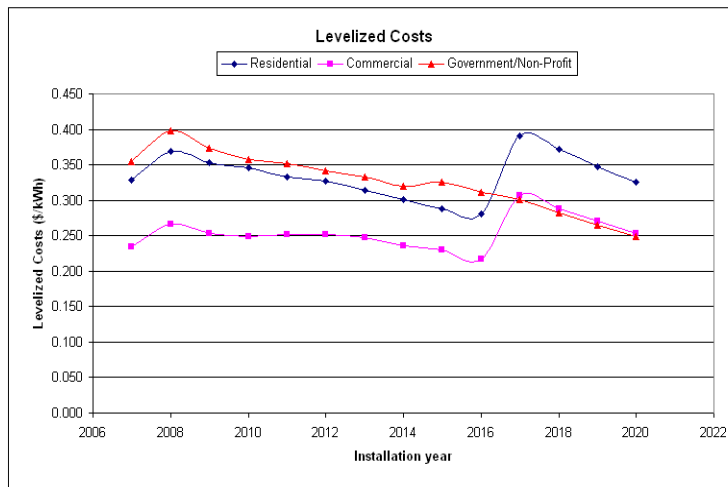
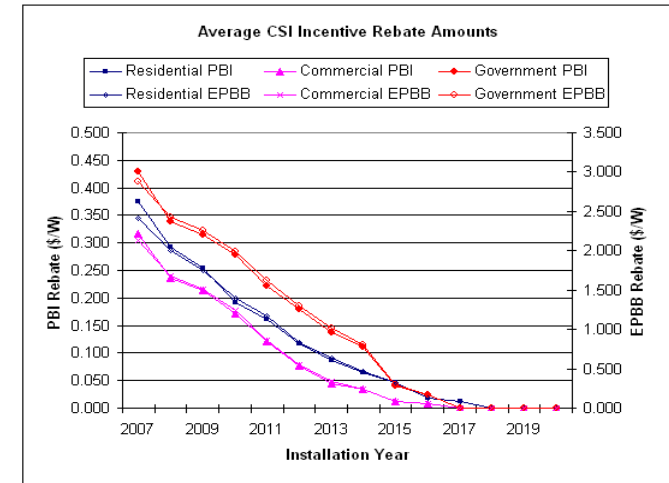
- Specify a desired levelized cost (\$/kWh) and calculate the system cost (\$/W) necessary to obtain desired LCOE.





# CSI Program Output

CSI program output is displayed showing differences in Residential, Commercial and Government /Non-Profit projects.





# Informal Evaluation

- Focus on individual pro forma
- Remember data are placeholders
  - Module costs and financing costs are approximate
  - Capacity factors, rates, learning curves are proxies
- Key areas for comment
  - Characterization of financing types
  - Reasonable balance of complexity and accuracy
  - Benchmarking – comparison to your analysis tool?



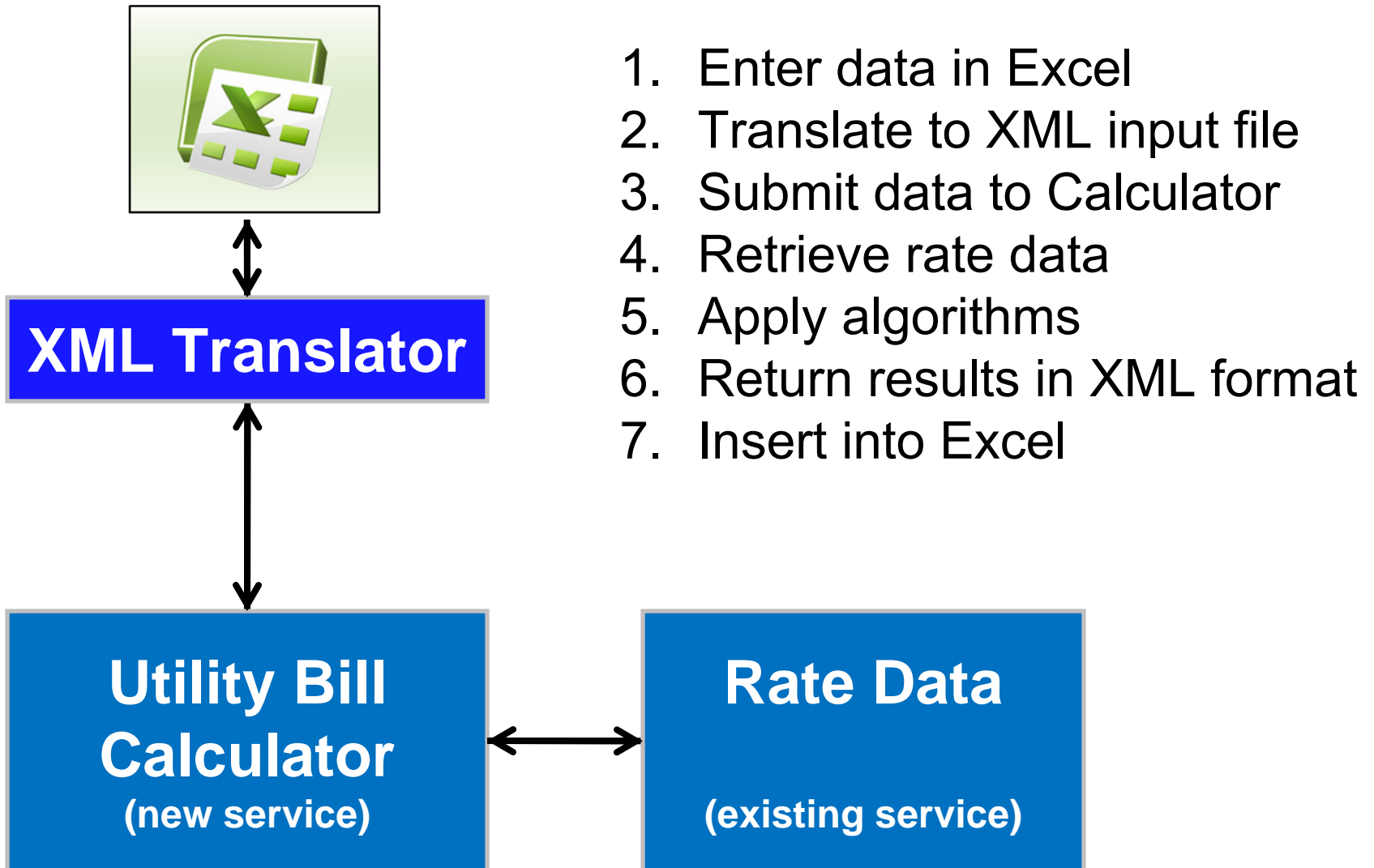
# Customer Bill Calculations

# Bill Calculation via web service

- Tool developed by Clean Power Research
- Uses rate data CPR previously developed
- Spreadsheet bill calculation
- Balance of complexity and transparency
- Testing is underway including the development of the results today
- Tentative release publicly for testing 12/4



# Calculation Process



# Step 1

## Translate data from Excel ...

Demand Measurement			
Date and Time	Demand		
1/1/08 0:00	1.07749942	Utility Rate	Pacific Gas and Electric Company (PG&E), Residential Service (Rate E1 Area T)
1/1/08 1:00	0.828999788		
1/1/08 2:00	0.796499878		
1/1/08 3:00	0.766499817		
1/1/08 4:00	0.773999959		

## ... to XML input file

```
<?xml version="1.0" encoding="utf-8" ?>
- <BillCalculationRequest xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance" xml
  DemandIntervalConvention="IntervalEnd" DemandUnit="kWh" NetMeteringCreditCarryover
- <BillingPeriods xmlns="http://www.cleanpower.com/UtilityBillService">
  - <BillingPeriod PeriodId="1">
    - <PeriodDemandList>
      <PeriodDemand DemandDate="2008-01-01T00:00:00" Demand="1.07749942" />
      <PeriodDemand DemandDate="2008-01-01T01:00:00" Demand="0.828999788" />
      <PeriodDemand DemandDate="2008-01-01T02:00:00" Demand="0.796499878" />
      <PeriodDemand DemandDate="2008-01-01T03:00:00" Demand="0.766499817" />
```

# Step 2

Perform calculations and create XML output file...

```

<?xml version="1.0" encoding="utf-8" ?>
- <UtilityBill xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance" xmlns:xsd="http://www.w3.org/2001/XMLSchema"
  <UtilityRate RateId="CA_PGE_E1_T_B" Description="Residential Service (Rate E1 Area T)" xmlns="http://www.cleanpower.com/UtilityBillService">
- <PeriodUtilityBills xmlns="http://www.cleanpower.com/UtilityBillService">
- <PeriodUtilityBill BillingPeriodId="1" TotalBillingPeriodCharge="201.28348060525618876712328767">
  - <BillingSeasons>
    - <BillingSeason SeasonNumber="1" SeasonName="Winter" HoursInSeason="744" WeightingFactor="1" MaxDemand="
      <MinimumBill Amount="4.5" WeightedAmount="4.5" />
    - <EnergyConsumption>
      <Energy Tier="0" kWh="303.71506849315068493150684932" Price="0.11551" Amount="35.08212756164
      <Energy Tier="1" kWh="90.70684931506849315068493151" Price="0.13129" Amount="11.908902246575
      <Energy Tier="2" kWh="213.00821917808219178082191781" Price="0.26098" Amount="55.59088504109
      <Energy Tier="3" kWh="259.15445506469863013698630136" Price="0.38086" Amount="98.70156575594
  
```

... and insert results into Excel spreadsheet

	January 2008			February 2008		
(PG&E), Residential Service (Rate E1 Area T)	Quantity	Price	Total	Quantity	Price	Total
Energy Consumption						
Tier 0	303.71507	0.11551	\$35.08	284.12055	0.11551	\$32.82
Tier 1	90.70685	0.13129	\$11.91	84.85479	0.13129	\$11.14
Tier 2	213.00822	0.26098	\$55.59	199.26575	0.26098	\$52.00
Tier 3	259.15446	0.38086	\$98.70	101.05507	0.38086	\$38.49
<b>Total Bill for Billing Cycle</b>			<b>\$201.28</b>			<b>\$134.45</b>



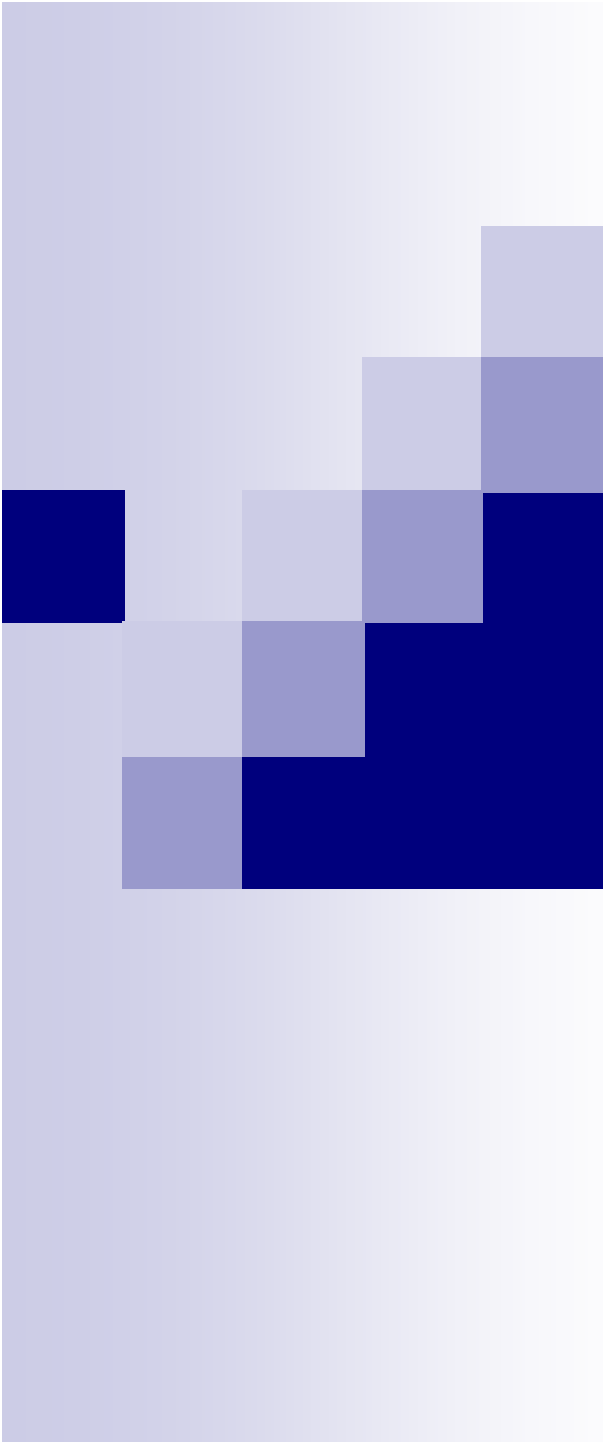
# Rates by Utility

## PG&E

Agricultural Power (Schedule AG-1)  
Agricultural Power Large Time-of-Use (Schedule AG-5)  
Agricultural Time-of-Use Service (Schedule AG-4A)  
Agricultural Time-of-Use Service (Schedule AG-VA)  
Large General Demand Service (Schedule E-20P Firm)  
Medium General Demand-Metered TOU Service (E-19 Primary)  
Medium General Demand-Metered TOU Service (E-19 Secondary)  
Medium General Service (Schedule A-10 - Secondary)  
Medium General Service (Schedule A-10 TOU - Secondary)  
Residential Seasonal Service (Rate E8)  
Residential Service - All Electric House (Rate E1)  
Residential Service (Rate E1)  
Residential Service Master metered, multi-family (Rate EM)  
Residential Service Optional Seasonal (Rate E8)  
Residential Time-of-Use - All Electric House (Rate E6)  
Residential Time-of-Use - All Electric House (Rate E7 )  
Residential Time-of-Use (Rate E7 )  
Residential Time-of-Use (Rate E6 )  
Small General Service (Schedule A-1)  
Small General Time-of-Use Service (Schedule A-6)



<b>SCE</b>	Distributed Generation Renewable - Time Metered (Schedule DG-R, <500 kW, Secondary) Domestic TOU for Households with Solar Energy System (DR-SES) General Service - Time Metered (AL-TOU) General Service - Time Metered (AY-TOU) General Service (Schedule A - Secondary) Residential Service - All Electric House (Rate DR ) Residential Service - Time Metered (DR-TOU) Residential Service - Time Metered All Electric (DR-TOU) Residential Service (Rate DR)
<b>SDG&amp;E</b>	Domestic Service (D, Region 10, All Electric Allocation) Domestic Service (D, Region 10, Basic Allocation) Domestic TOU (TOU-D-1, Region 10, All Electric Allocation) Domestic TOU (TOU-D-1, Region 10, Basic Allocation) Domestic TOU (TOU-D-2) General Service - Demand - Time of Use (GS-2 TOU Option R) General Service - Demand (GS-2 TOU Option A) General Service - Demand (GS-2 TOU Option B) General Service - Demand (GS-2) General Service - Non-Demand (GS-1) General Service - TOU - Large (TOU-8 < 2kV) General Service - TOU - Large Option R (TOU-8 < 2kV Option R) General Service - TOU Demand (TOU-GS-3 Option A < 2 kV) General Service - TOU Demand (TOU-GS-3 Option B < 2 kV) General Service - TOU Demand (TOU-GS-3 Option R < 2 kV) Power - Agricultural and Pumping (PA-1) TOU Agricultural & Pumping - Demand Metered (TOU-PA-5) TOU Agricultural & Pumping - Rate A (TOU-PA Rate A) TOU Agricultural & Pumping - Rate B (TOU-PA Rate B)



# Avoided Cost Methodology and Results



# CPUC DG Cost-Benefit Decision

- Decision 09-08-026, August 20, 2009
  - To compare resource options, evaluate effectiveness of DG
  - Applies broadly, but intended specifically for CSI and SGIP
- Adopts the following principles:
  - Multiple Perspectives
  - Builds on EE avoided cost methodology
  - Uses actual rates and program data where available
  - Environmental benefits as in EE evaluation
  - Includes prospective evaluation of market transformation



# CA Avoided Cost Timeline

- 2001: CEC adopted Time Dependent Valuation for Title 24 Building Standards
- 2004-ongoing: CPUC adopted long-run forecast of energy efficiency avoided costs
- 2007: CEC revised TDV values including RA payments and capacity allocation
- 2009: E3 developed DG avoided costs



# Avoided Cost Approach

- Non-proprietary, publicly available data
- Provide additional transparency by making spreadsheet freely available to download
- Differences to prior avoided cost framework adopted for energy efficiency
  - Updated 2008 price shape
  - Allocation of RA capacity value to hours
  - Added value of avoided renewable purchases

# “Screen Shot” of A/C Spreadsheet

Microsoft Excel - NEM Avoided Costs 11-18-09.xls

File Edit View Insert Format Tools Data Window Help

125%

Arial 10

E26

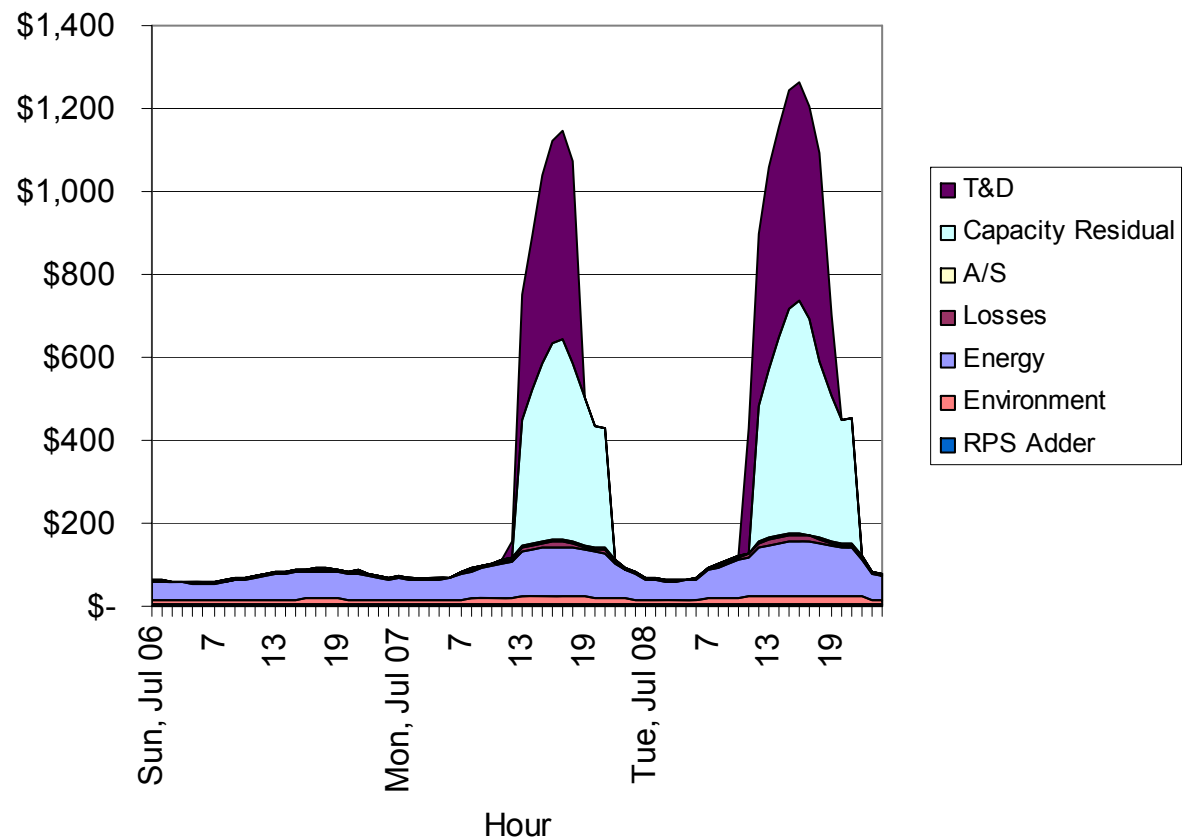
Calculation of TDV Values												
TDV Calculation Selection				Component Included in Hourly Calculation				Calculation Macros				
Climate Zone	12			Market	TRUE			Update Avoided Costs				
Measure Life	NEM Default (20-yr)			Residual Capacity	TRUE			Export Outputs to File				
Calendar	Jan 2008 - Dec 2008			T&D	TRUE							
Initial Year of Measure	2008			Environment	TRUE							
Cost Basis Year for Results	2008			RPS Adder	TRUE							
Measure Life	20											
Utility	PG&E											
Date and Time				TDV By Component								
Month	Hour	Day	Date	TOU Period	Energy	Losses	A/S	Capacity Residual	T&D			
1	1	1	1/1/2008 0:00	6	\$57.73	\$3.53	\$1.74	\$0.00	\$0.00			
1	2	1	1/1/2008 1:00	6	\$55.14	\$3.37	\$1.66	\$0.00	\$0.00			
1	3	1	1/1/2008 2:00	6	\$53.30	\$3.26	\$1.61	\$0.00	\$0.00			
1	4	1	1/1/2008 3:00	6	\$52.71	\$3.23	\$1.59	\$0.00	\$0.00			
1	5	1	1/1/2008 4:00	6	\$52.84	\$3.23	\$1.59	\$0.00	\$0.00			
1	6	1	1/1/2008 5:00	6	\$53.27	\$3.26	\$1.61	\$0.00	\$0.00			
1	7	1	1/1/2008 6:00	6	\$54.42	\$3.33	\$1.64	\$0.00	\$0.00			
1	8	1	1/1/2008 7:00	6	\$54.90	\$3.36	\$1.65	\$0.00	\$0.00			

Cover Inputs Output TDVCalculate T&D Costs Emissions LossesAS EnergyCapacity CapacityResidual ISOloads MktData AvoidedRPS GenerationForecast CCGTcost

Ready Calculate NUM

# Components of Avoided Cost

- Generation
  - Energy
  - Capacity
- Transmission & distribution
- Emissions
- Losses
- Ancillary services
- Avoided RPS purchases

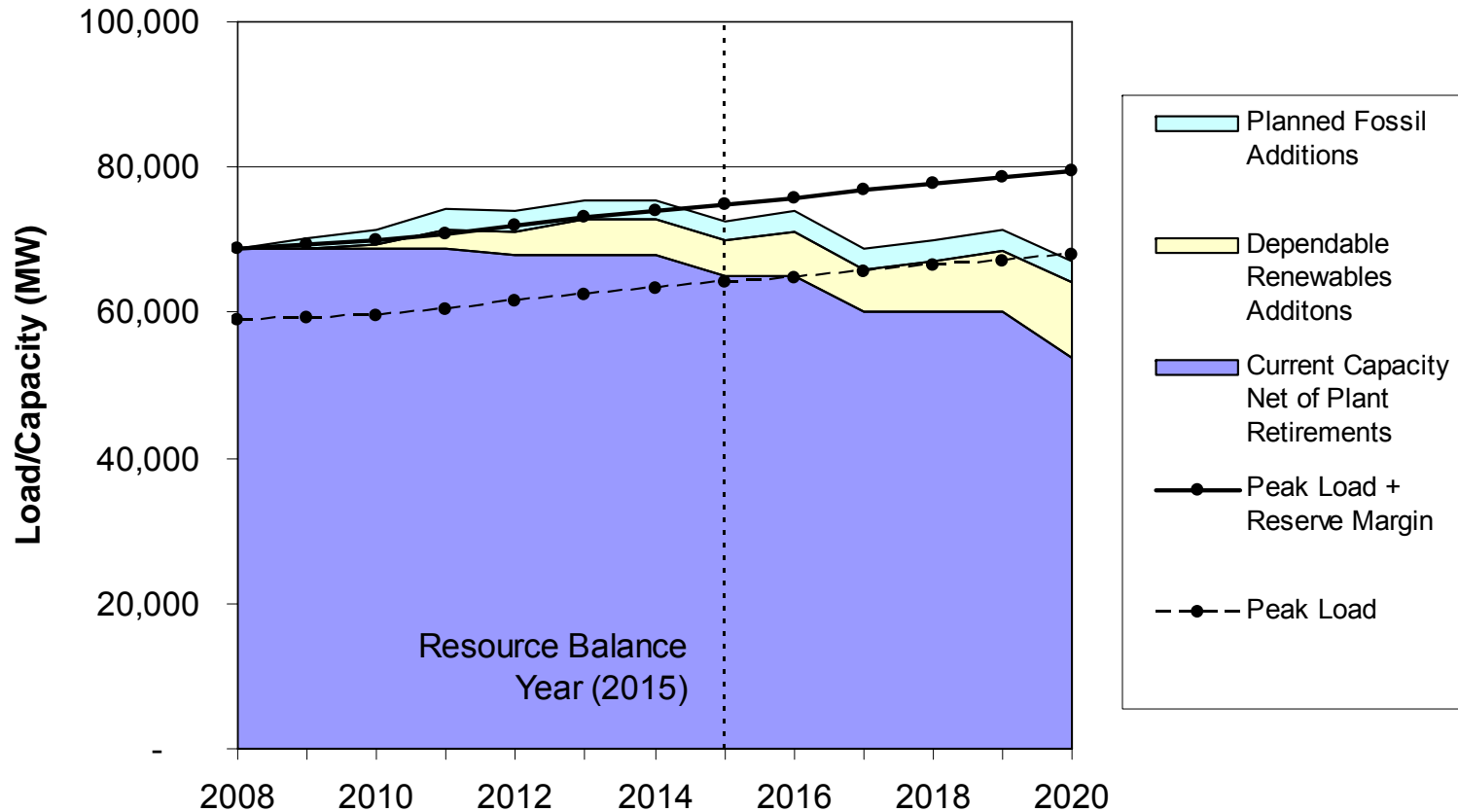




# Avoided Generation Costs

- Energy
  - Use historical price shapes from 2008 – 2009
  - Forecast using market data, then transition to long-run marginal cost of a CCGT
- Capacity
  - Use historical price of resource adequacy
  - Forecast assuming transition to full residual capacity value of CT
- For both components (energy & capacity), there are short run and long run values; the transition point between the two is the resource balance year

# Resource Balance Year



**Sources:** Forecast of peak load is CEC's latest 10-year load forecast (<http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html>); capacity buildout is based on E3's 33% model (33% Reference Case)

# Capacity Additions for Resource Balance Year

Incremental RPS Resources		
	Total	
	MW	GWh
Biogas	279	2,078
Biomass	429	3,003
Geothermal	1,497	11,471
Hydro - Small	40	177
Solar PV	3,165	6,765
Solar Thermal	6,512	16,084
Wind	8,339	24,548
<b>Total</b>	<b>20,260</b>	<b>64,126</b>

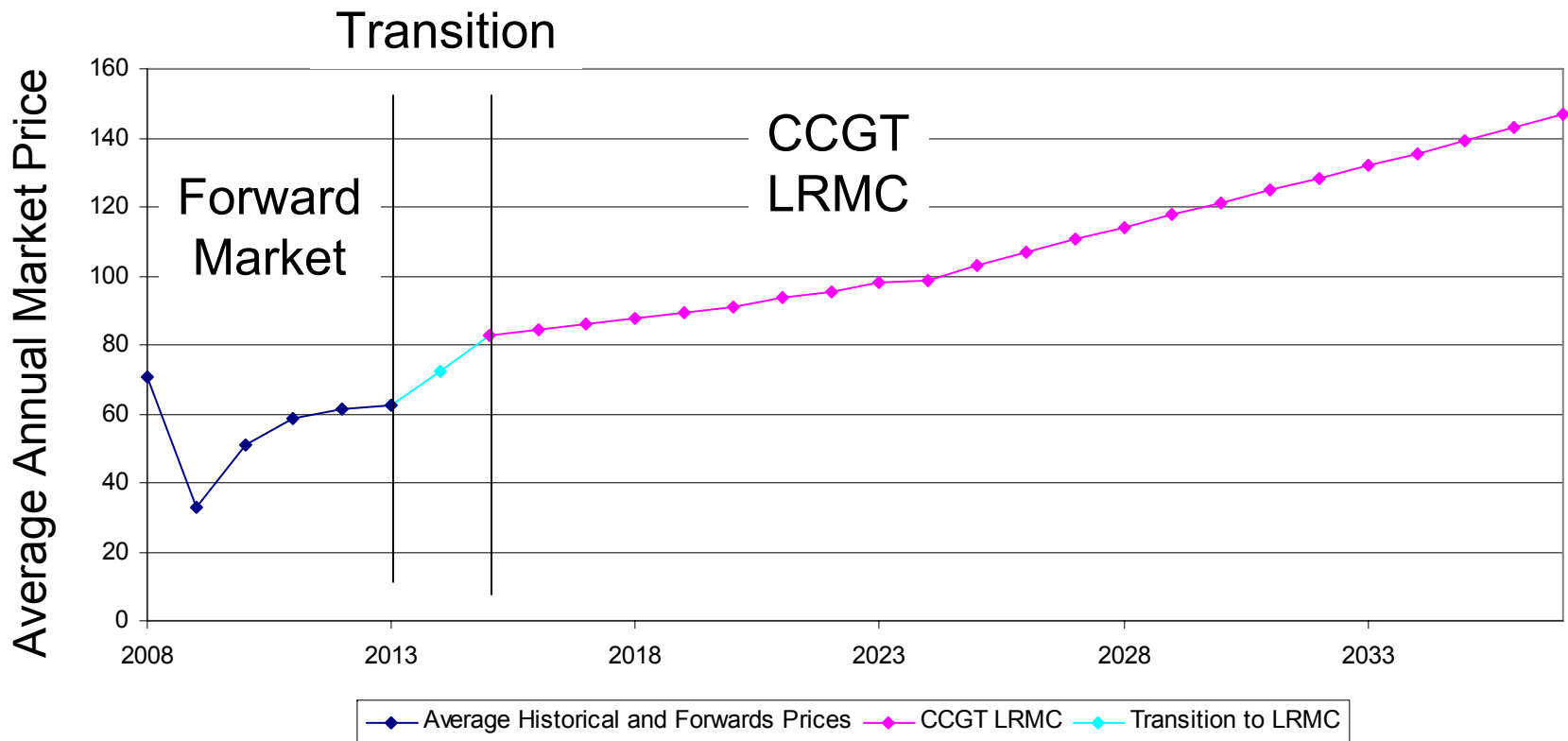
Source: 33% Reference Case RPS Build

- Renewable additions based on 33% model's buildout to reach 33% RPS in 2020
- Fossil additions include plants classified by the CEC as "Operational," "Partially Operational," and "Under Construction"

Planned Fossil Additions (from CEC Database)				
	Type	Status	MW	GWh
Gateway - PG&E	CCGT	Operational	530	2,554
Inland Empire - GE	CCGT	Partially Operational	400	1,927
Colusa Generation Station - PG&E	CCGT	Under Construction	660	3,180
Otay Mesa - Calpine	CCGT	Operational	590	2,843
EIF Panoche - Energy Investors Fund	CT	Operational	400	350
Starwood Midway - Starwood Power	CT	Operational	120	105
Orange Grove AFC - J Power USA	CT	Under Construction	96	84
<b>Total</b>			<b>2,796</b>	<b>11,043</b>

Source: [http://www.energy.ca.gov/sitingcases/all\\_projects.html](http://www.energy.ca.gov/sitingcases/all_projects.html)

# Effect of Resource Balance Year on Market Forecast



LRMC becomes the market price in resource balance year (2015)

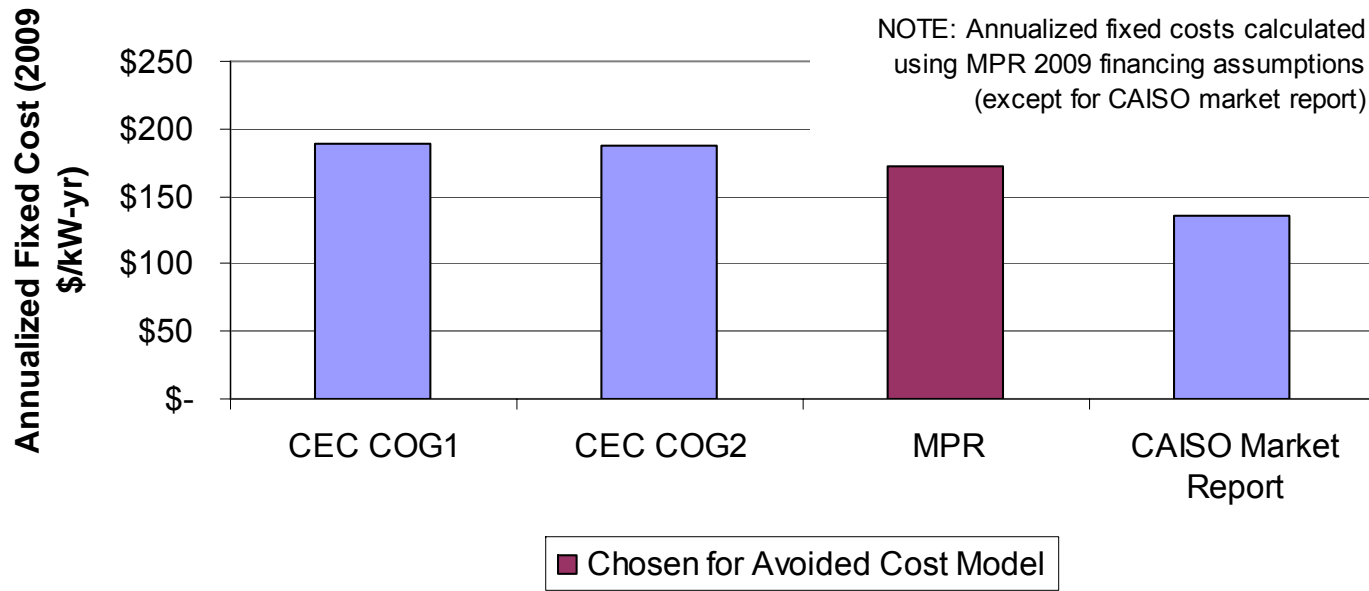
# LRMC Calculation

- Long-run marginal cost based on all-in cost for a CCGT
- CCGT specifications based on 2009 MPR update

	CCGT
Annualized Fixed Cost (\$/kW-yr)	\$ 172.38
Fixed O&M (\$/kW-yr)	\$ 10.20
Variable O&M (\$/MWh)	\$ 4.74
Heat Rate (MMBtu/kWh)	6,924

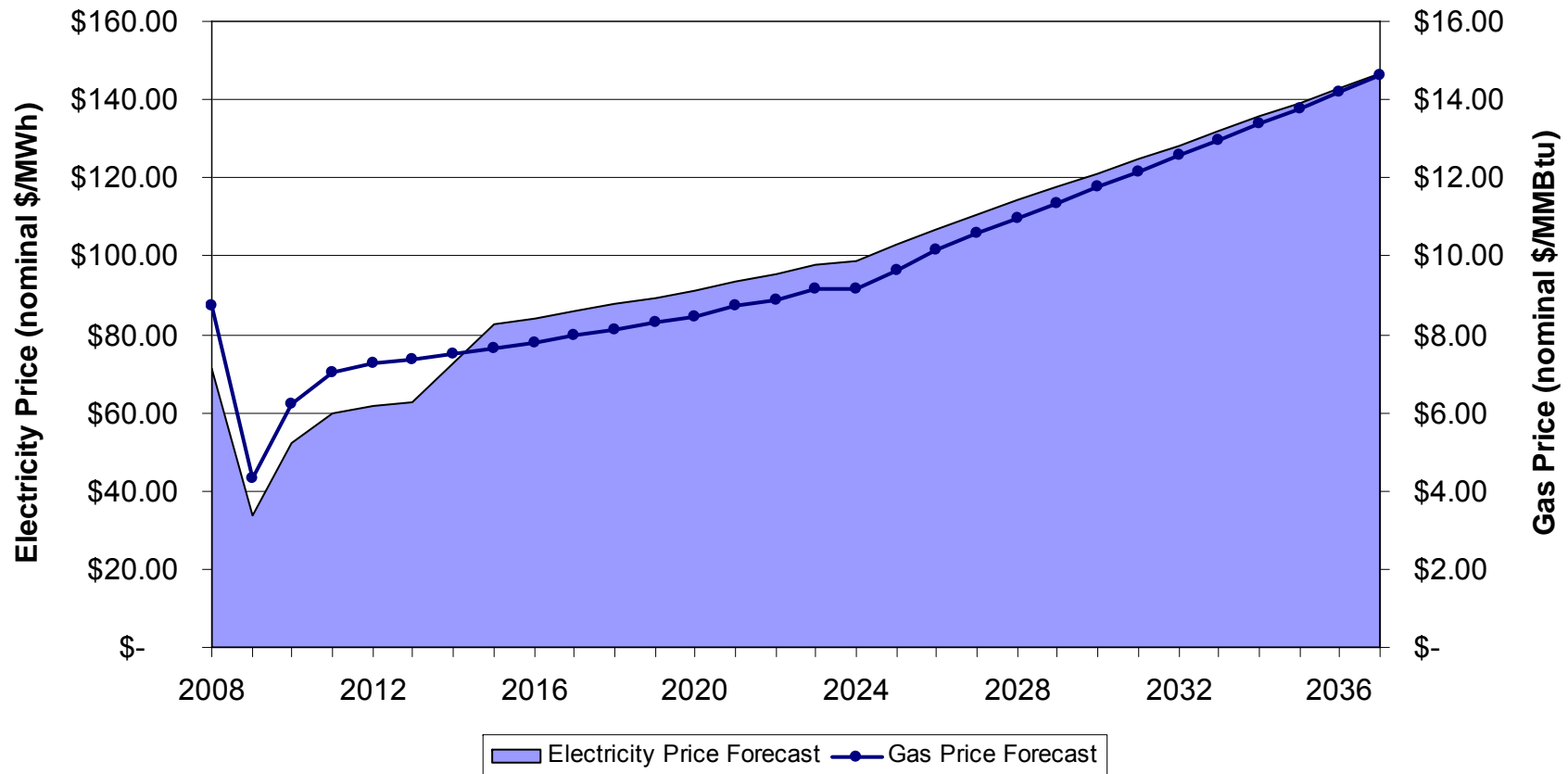
(costs in 2009 \$)

**Comparison of CCGT Annualized Fixed Costs**



Financing assumptions taken from 2009 update of MPR: Debt-to-equity ratio: 50%, Cost of debt: 7.7%, Cost of equity: 12.0%

# Electricity and Gas Price Forecast



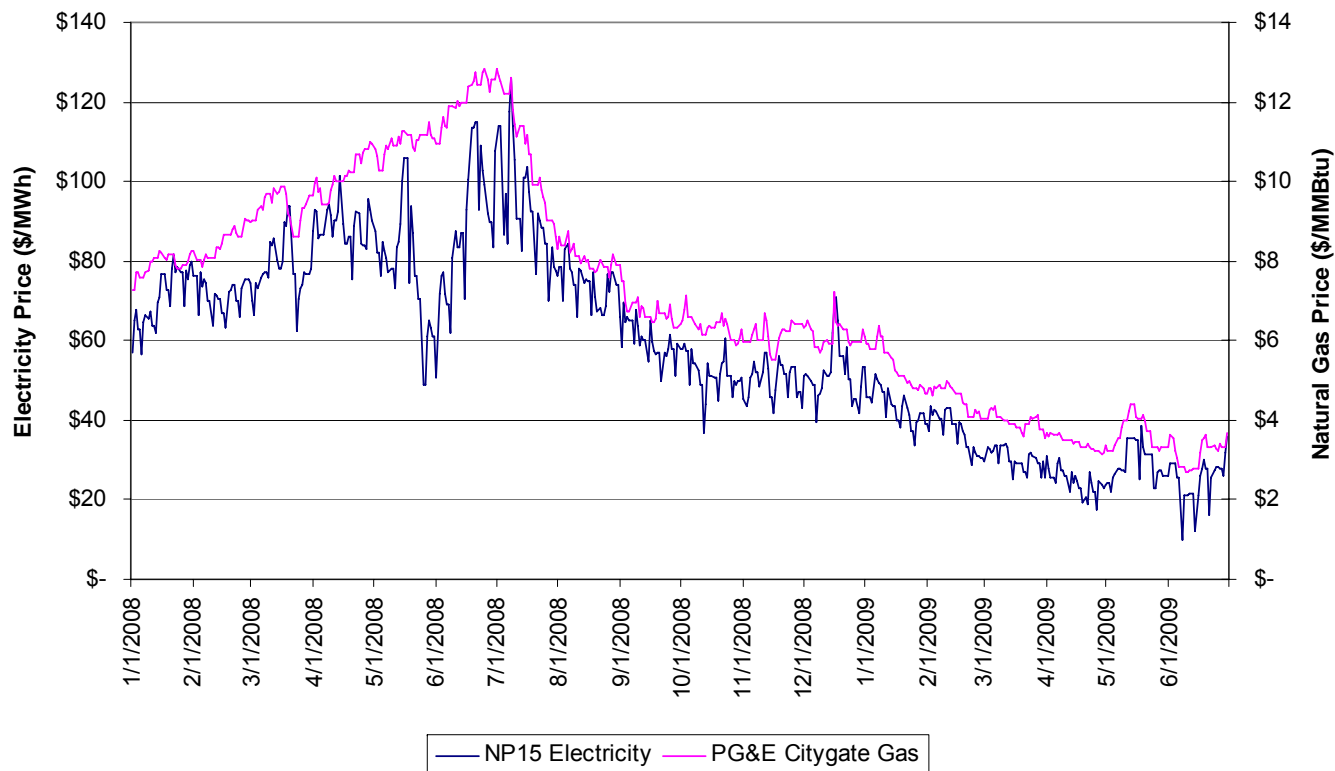
Gas price forecast shown and used in avoided cost calculation is the same as used in the calculation of the 2009 MPR



# Hourly Market Price Shape

- To value NEM correctly, hour-by-hour and day-by-day price shape must be preserved to match solar PV output
- To match correlate data with PV production data, we develop market price shapes for two calendars
  - Jan 08 – Dec 08
  - Jul 08 – Jun 09
- At the same time, because of natural gas price volatility and other market factors, the market price shape from electricity from 2008 through mid-2009 does not follow expected trends on a monthly basis

# Daily Market Gas and Electricity Prices, Jan 08 to Jun 09

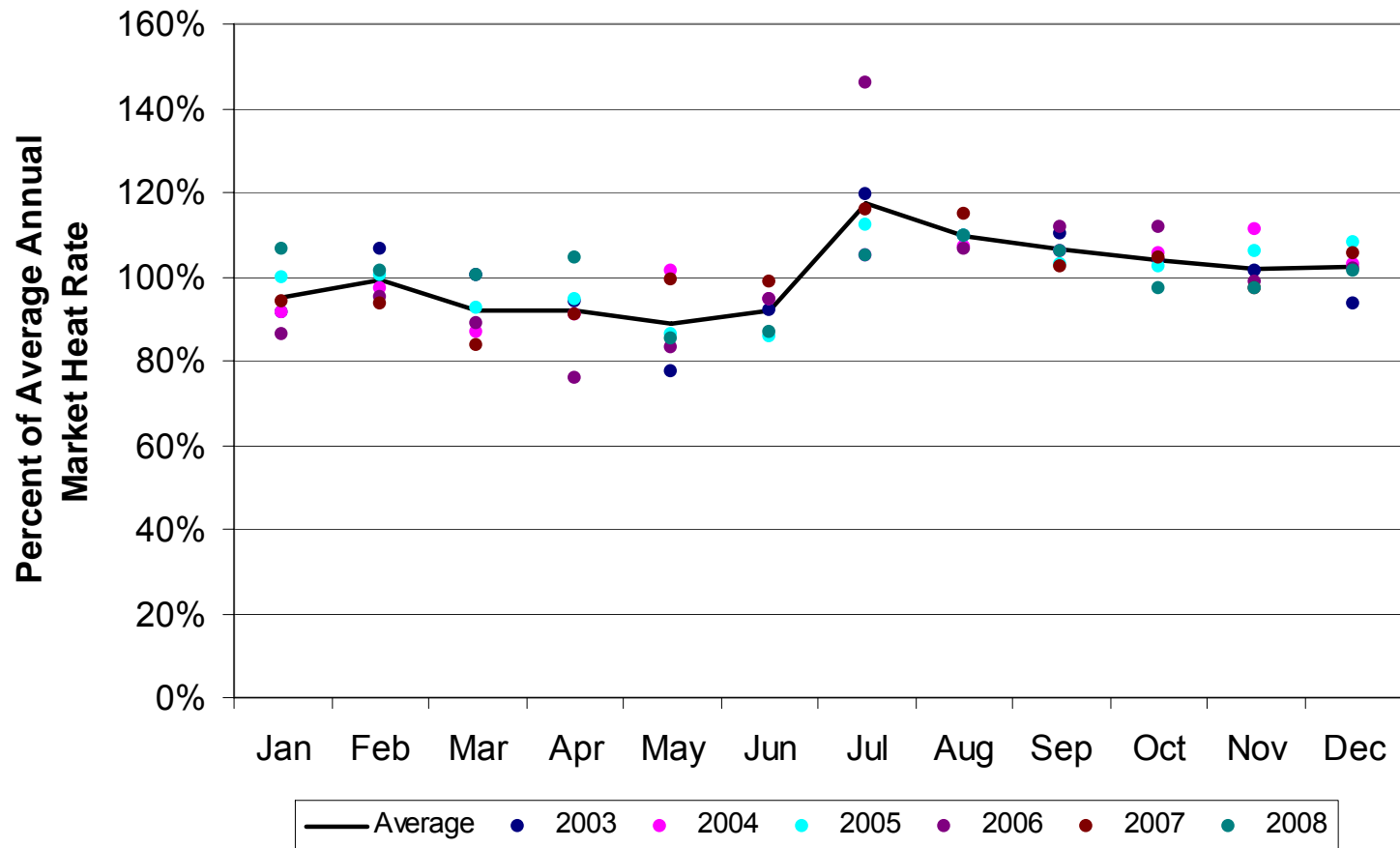




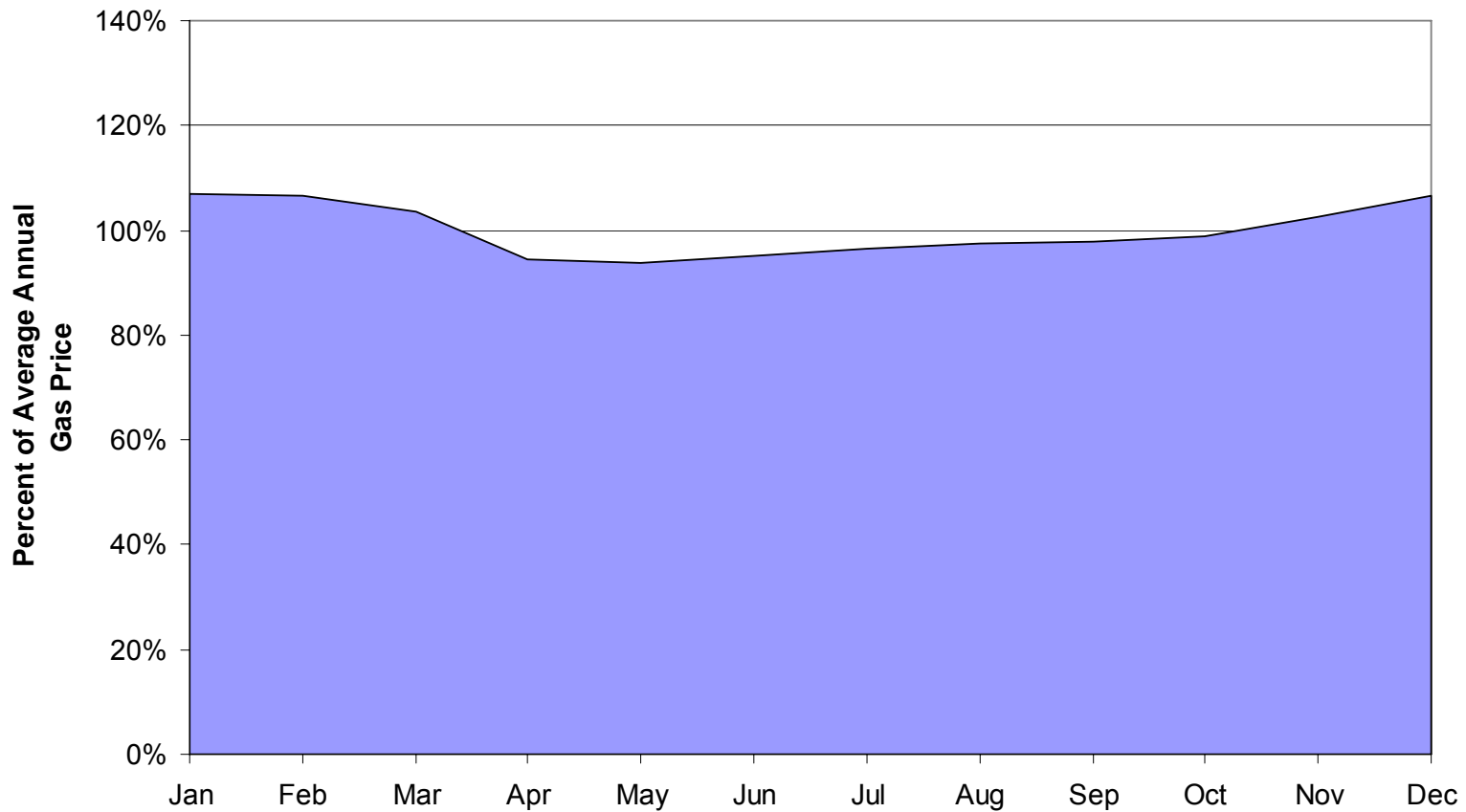
# Market Price Shape

- Two step process
  1. Use historical market heat rates and monthly natural gas forwards to develop estimates of relative average market prices by month
  2. Use actual market price data from each month to introduce daily and hourly shaping
    - CAISO hourly loads are used to scale peak/off-peak prices in order to achieve hourly resolution

# Historical Market Heat Rates, NP15



# Shape of Monthly Natural Gas Forwards

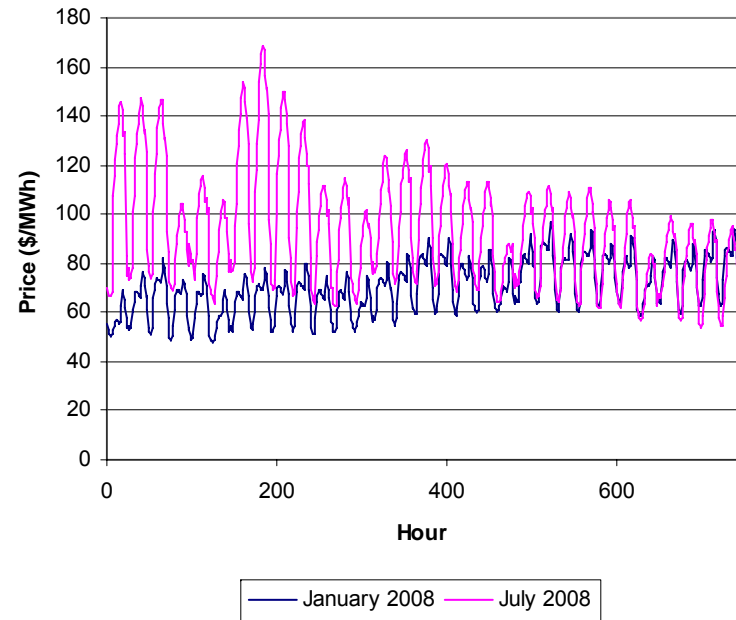
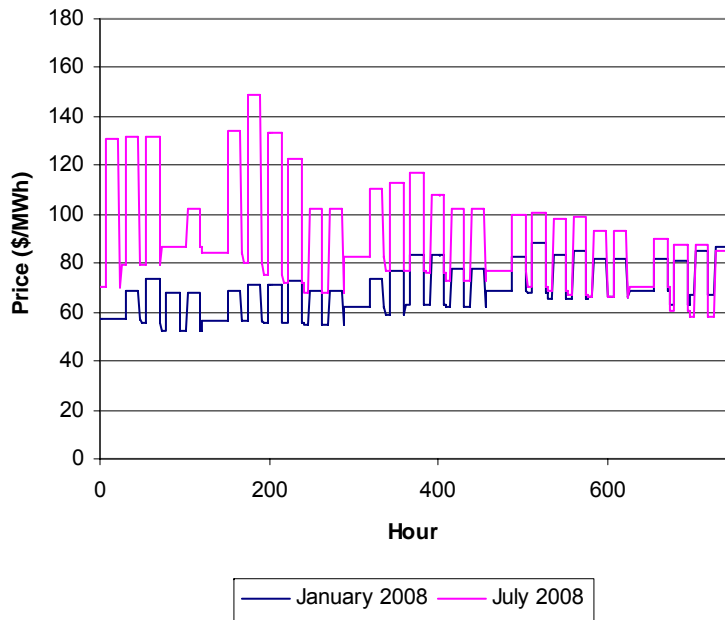




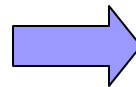
# Converting Average Monthly Prices to Hourly Prices

- Ideally, market price shape would be based on CAISO's MRTU reporting for NP/SP15
  - Since MRTU was implemented beginning 4/1/09, a year's worth of data is not available and this is not an option
- Next best option is to use peak/off-peak market prices scaled by CAISO hourly loads
  - General shape of market prices is captured in the process, but scaled shapes do miss out on some of the market's volatility and major peaks

# Scaling Peak/Off-Peak Prices Using Hourly Loads

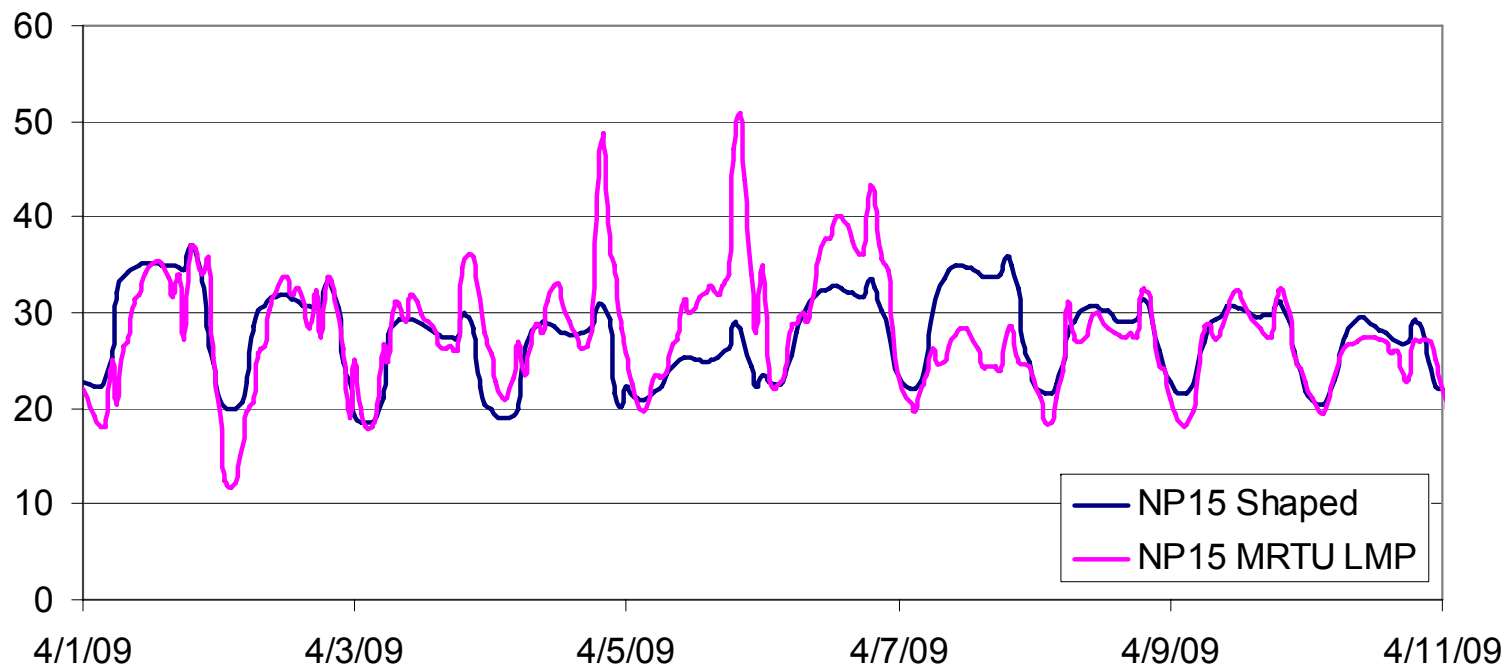


Peak/off-peak prices

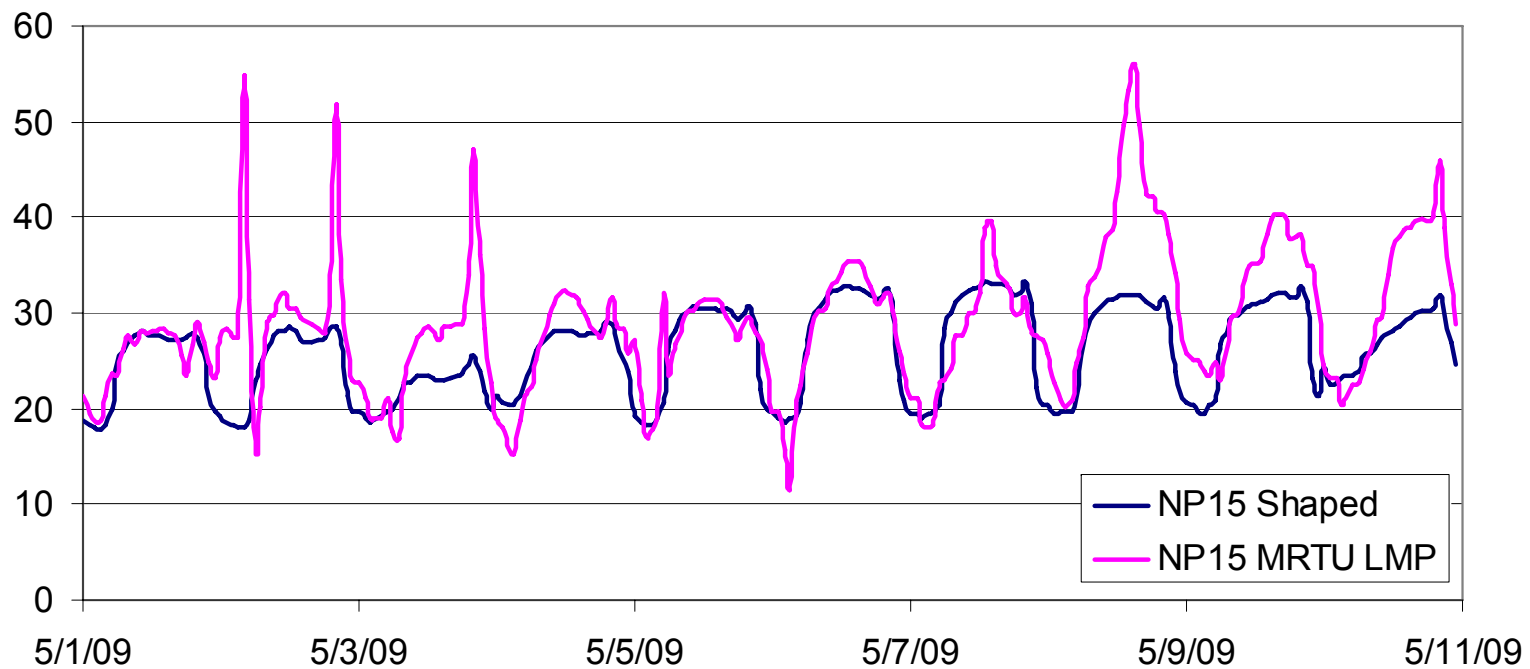


Hourly prices shaped by loads

# Comparison of Scaled Market Prices with Available MRTU Data (10-Day Snapshots)

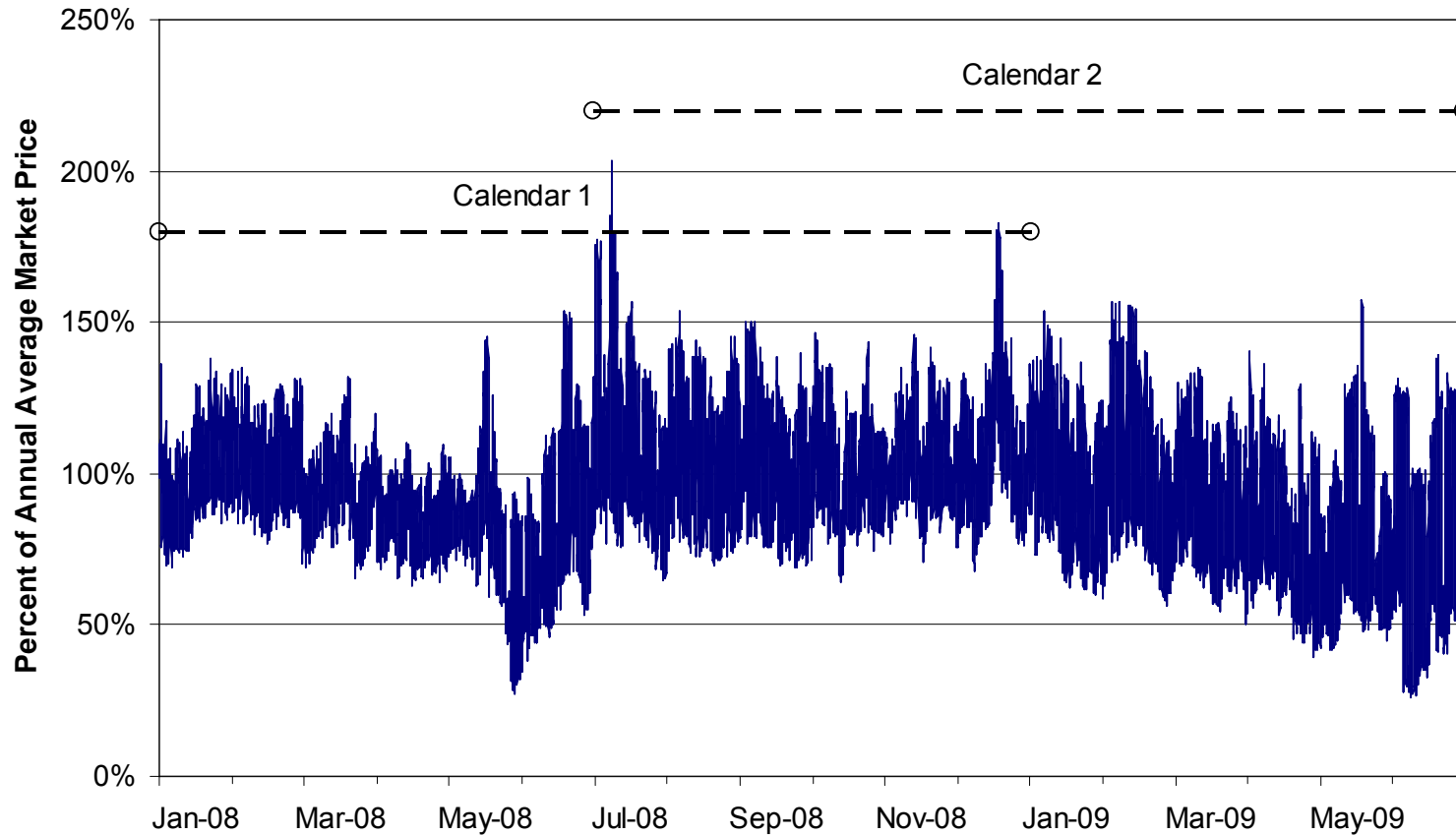


# Comparison of Scaled Market Prices with Available MRTU Data (10-Day Snapshots)

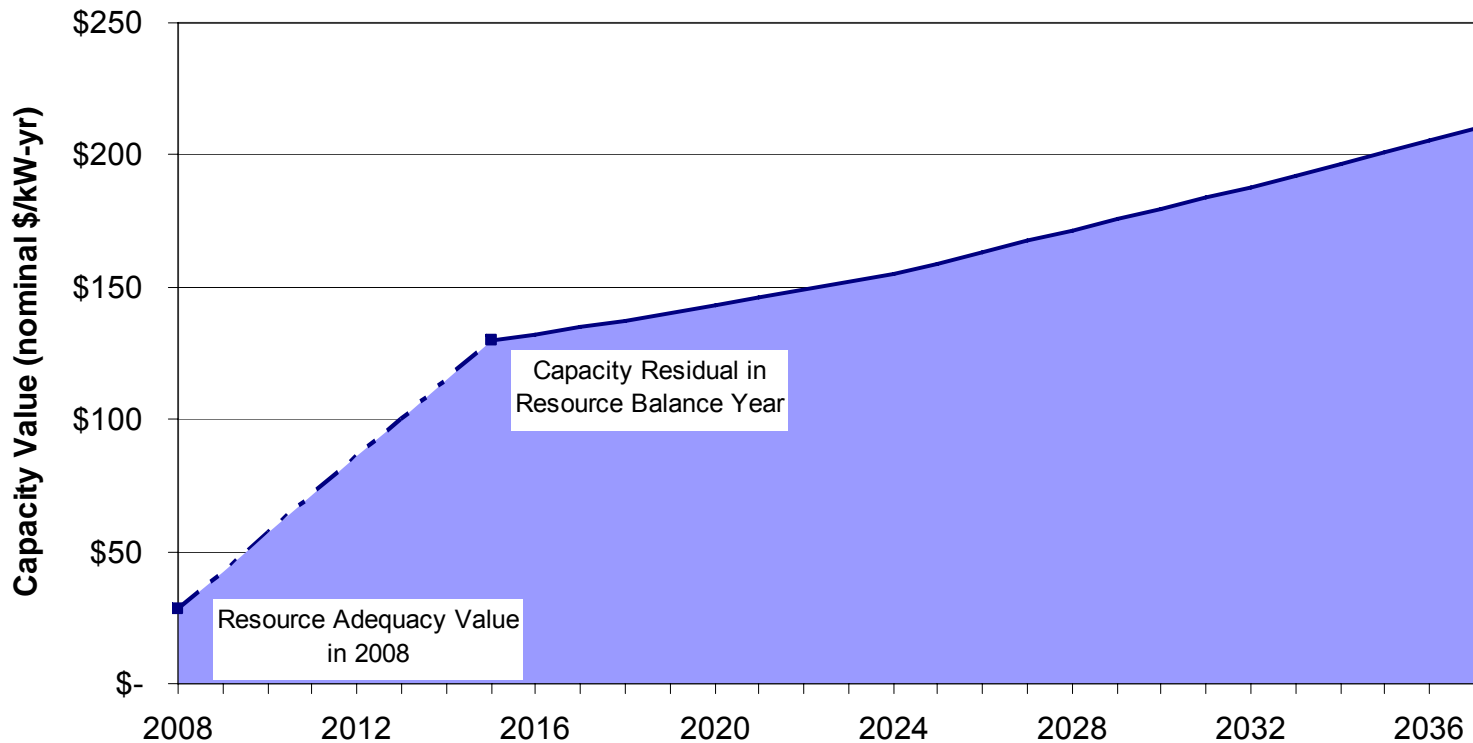




# Resulting Market Price Shape (NP15)



# Generation Capacity Value



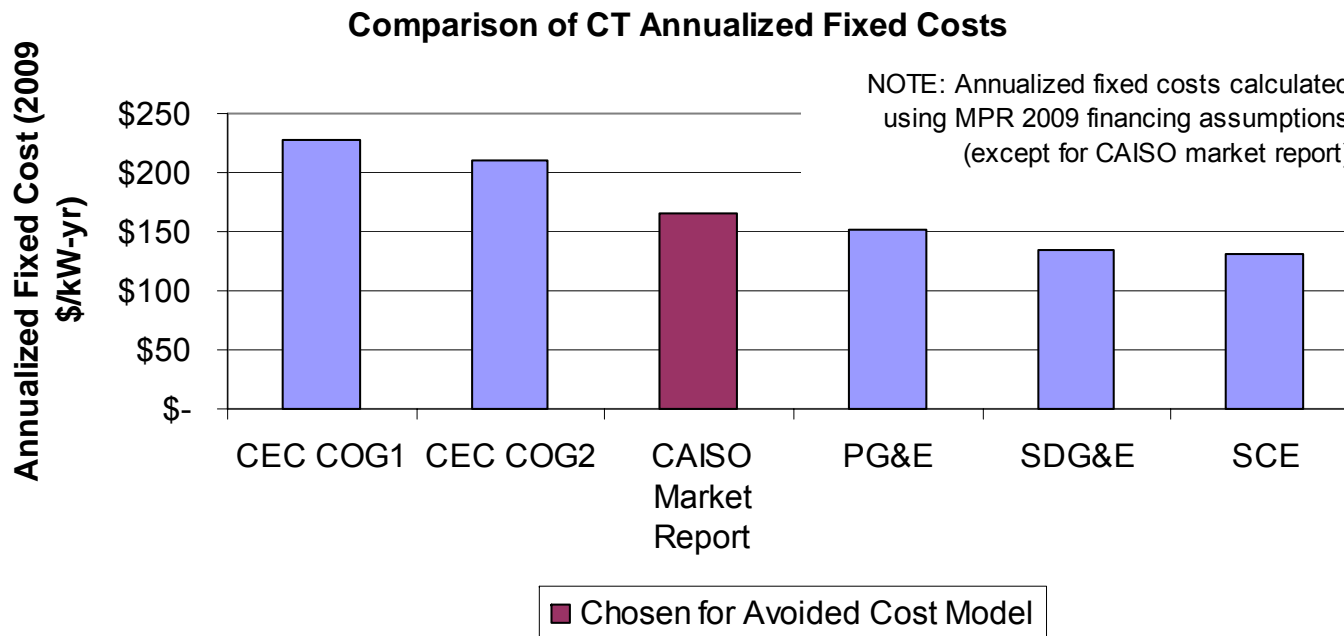
- Short term capacity value (2008-resource balance year) is based on a linear interpolation between 2008 RA value and the capacity residual in the resource balance year
- 2008 RA value based on CAISO Sunrise Phase 2 Proceedings
- Long term capacity value (post resource balance year) is the capacity residual for a CT

# Calculation of Capacity Residual

- Capacity residual is annualized fixed cost for a CT net of revenue in energy markets
- CT specifications taken from CAISO market report

	CT
Annualized Fixed Cost (\$/kW-yr)	\$ 165.34
Fixed O&M (\$/kW-yr)	\$ 21.22
Variable O&M (\$/MWh)	\$ 11.12
Heat Rate (MMBtu/kWh)	9,300

(costs in 2009 \$)





# Calculation of Gross Margin

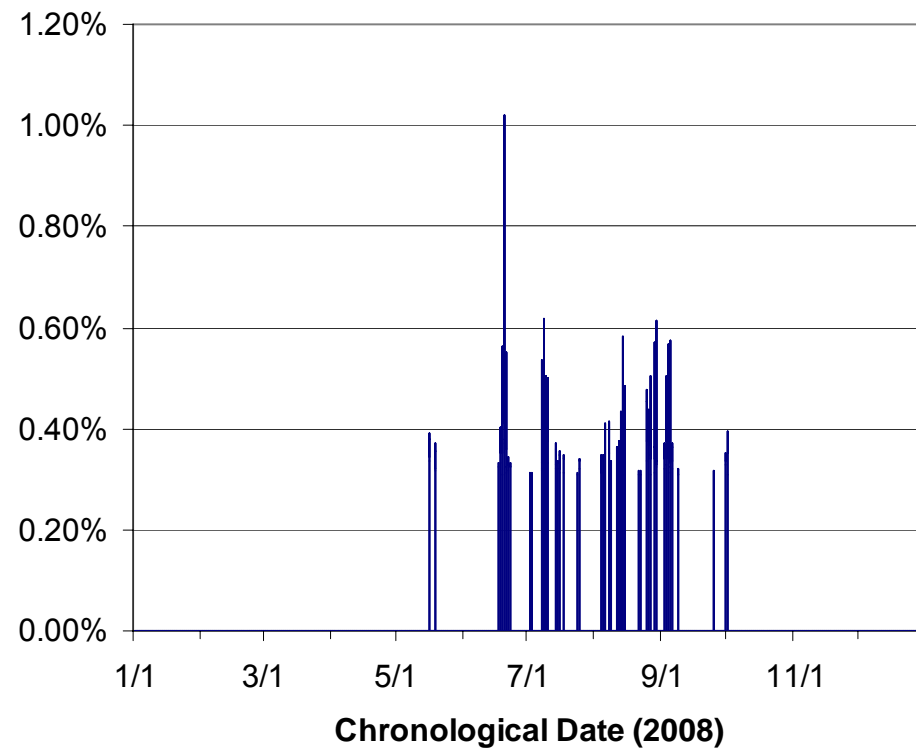
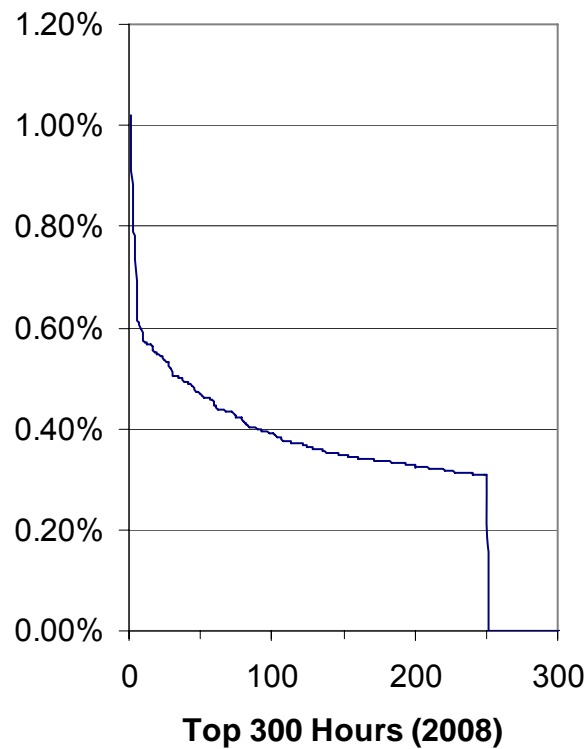
- Dispatch when variable cost < market price<sub>hourly</sub>
- Gross margin<sub>hourly</sub> = market price<sub>hourly</sub> – variable cost
- Annual gross margin = sum [gross margin<sub>hourly</sub>]
- For example (costs in nominal \$)
  - 2015 gross margin = \$56.73/kW-year



# Allocation of Generation Capacity Value

- Capacity allocators are calculated for each of the top 250 load hours
- The allocator for each hour is inversely proportional to the difference between the peak period capacity and the load in that hour
  - Peak period capacity is the annual peak load plus the reserve margin
- Allocators are normalized to sum to 100%

# Allocation of Generation Capacity Value



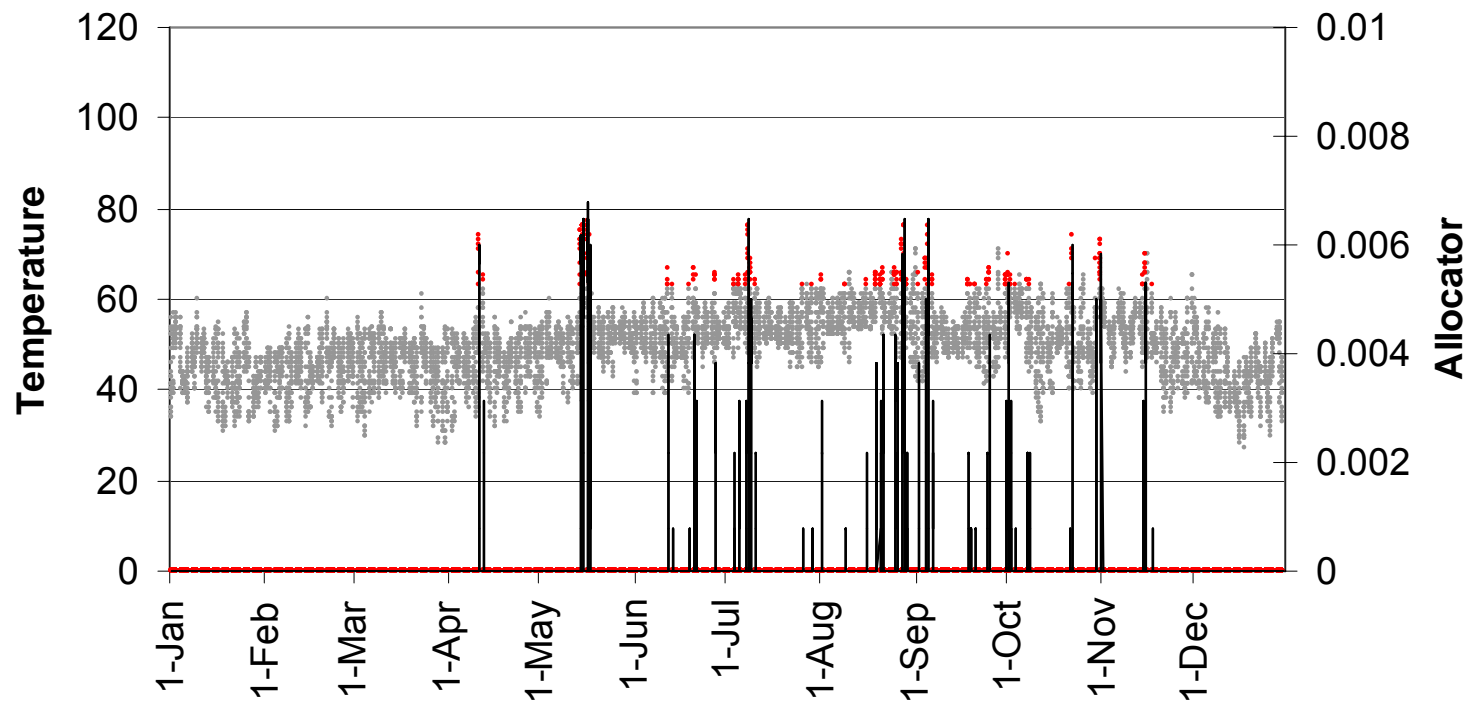
- Capacity value is allocated to the top 250 load hours



# T&D Avoided Costs

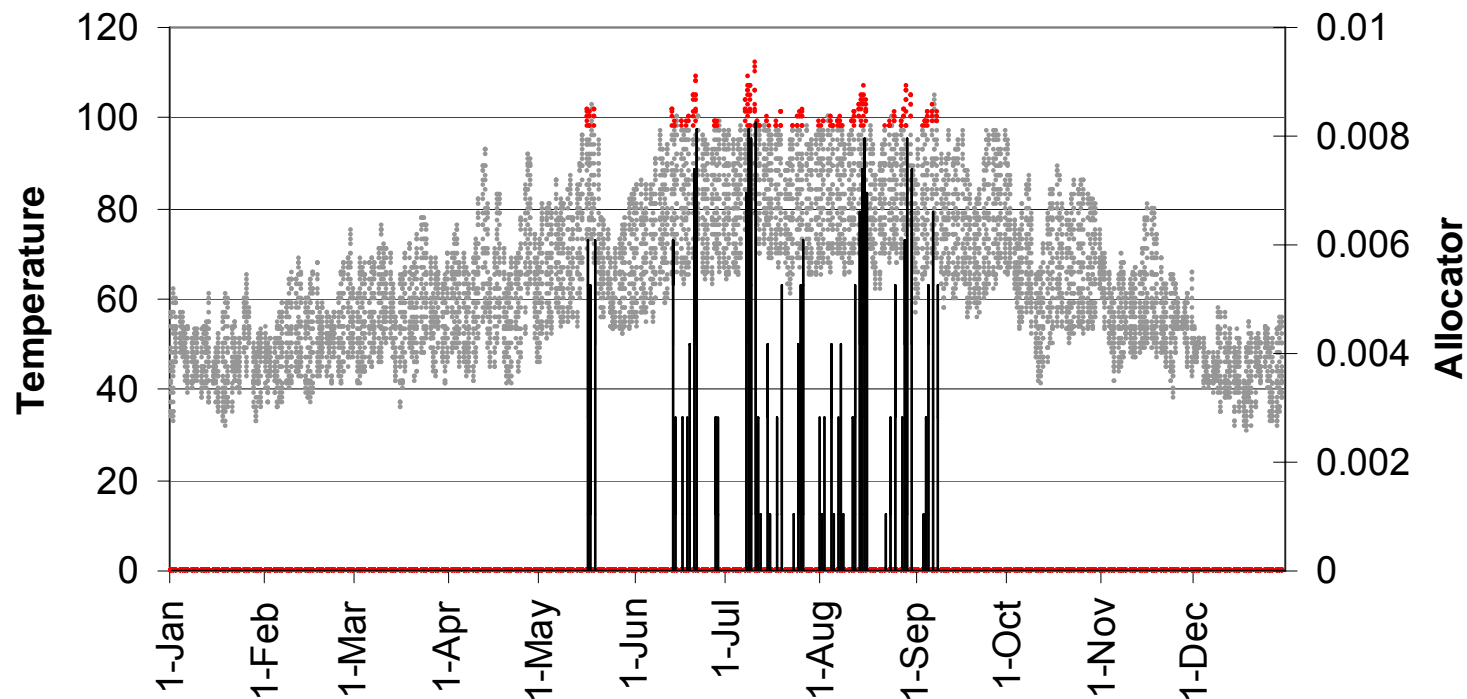
- Adopting the same T&D avoided cost estimates
- Data comes from general rate cases and is time-intensive to assemble
  - Not updated from EE Avoided Cost calculator
- Allocators based on updated temperature profiles for 2008 through mid-2009
  - T&D costs allocated to the hottest hours of the year (hours within 15°F of the annual peak temperature)
  - In general, hottest hours are likely to have highest local loads

# Example Temperature Profile and Allocators (CZ1 – Arcata, 2008)



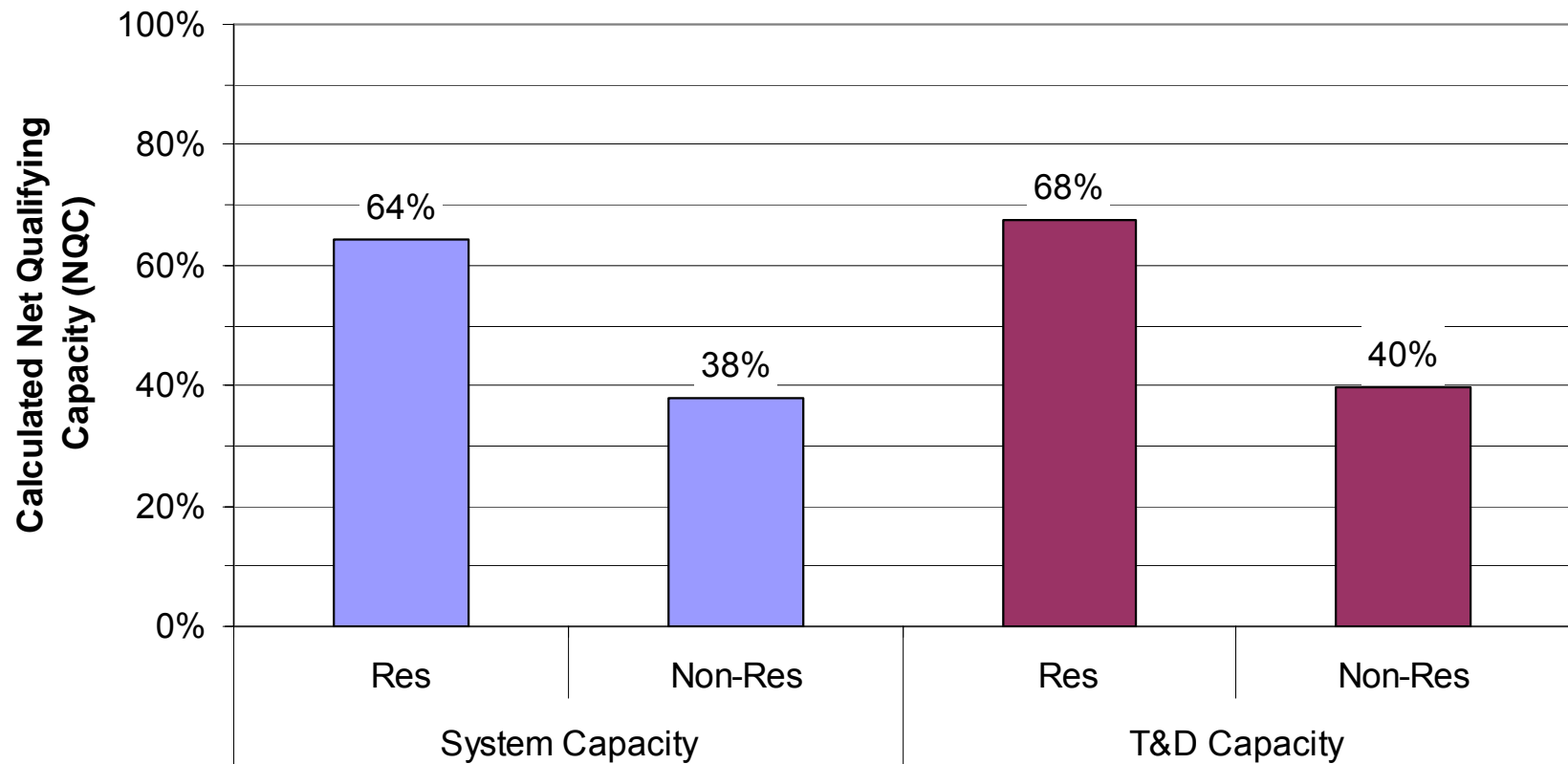
For a coastal zone with a relatively flat temperature profile, T&D costs are allocated throughout much of the year

# Example Temperature Profile and Allocators (CZ13 – Fresno, 2008)



For an inland zone with a strong summer temperature peak (and large AC loads), T&D costs are allocated primarily in the summer

# Net Qualifying Capacity Equivalent (Sample Systems in CZ3)





# Losses and Ancillary Services

- Losses are calculated based on climate zone and TOU period
  - Utility-specific TOU loss factors are used
- Avoided cost model assumes that ancillary services benefits in each hour are equal to 2.8% of market energy price and the value of losses



# Environmental Benefits

- Cost of permits for criteria air pollutants is included in plant capital cost (and hence the capacity value)
- Carbon dioxide is assigned value based on mid-level Synapse price forecast
- Marginal emissions level is calculated based on implied heat rate of marginal generator

# Synapse Carbon Price Forecasts

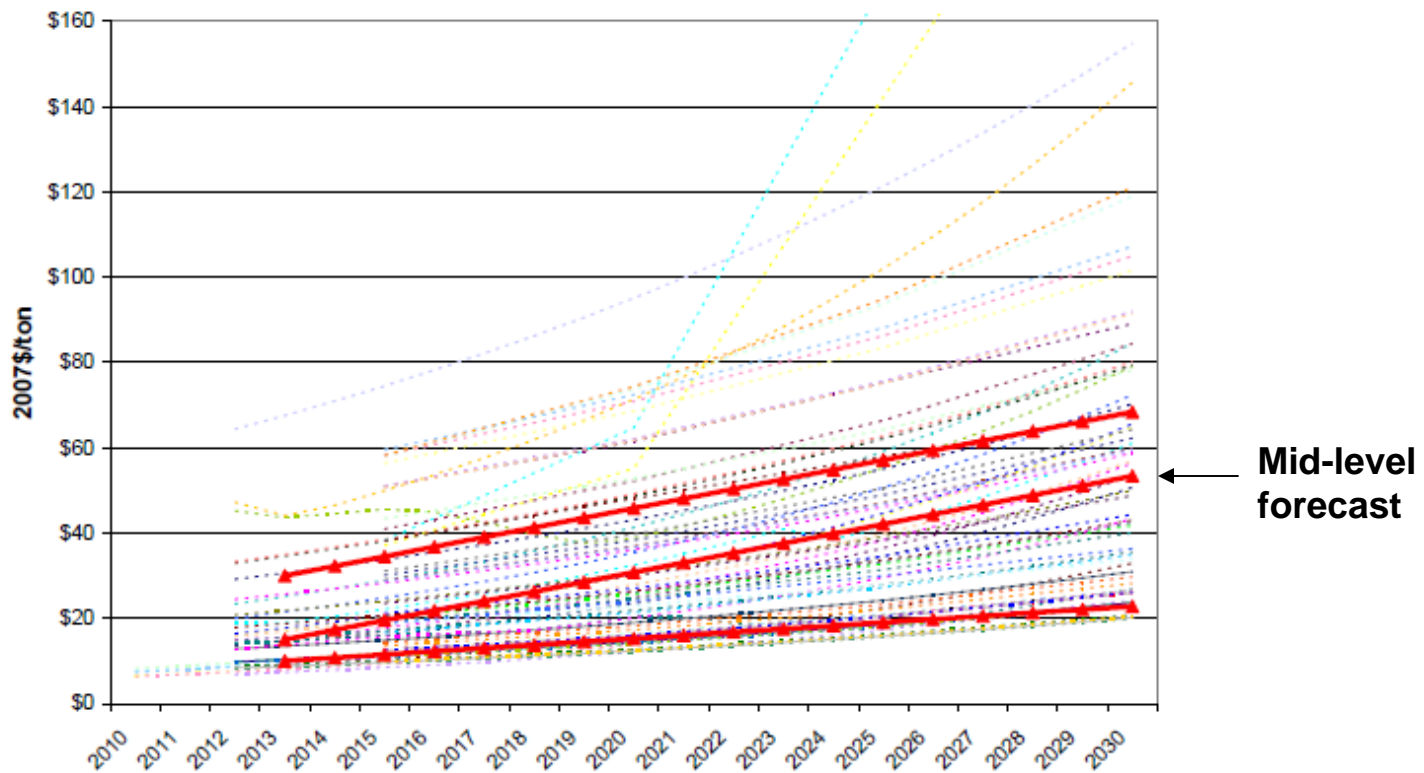


Figure obtained from: <http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf>



# Avoided RPS Purchases

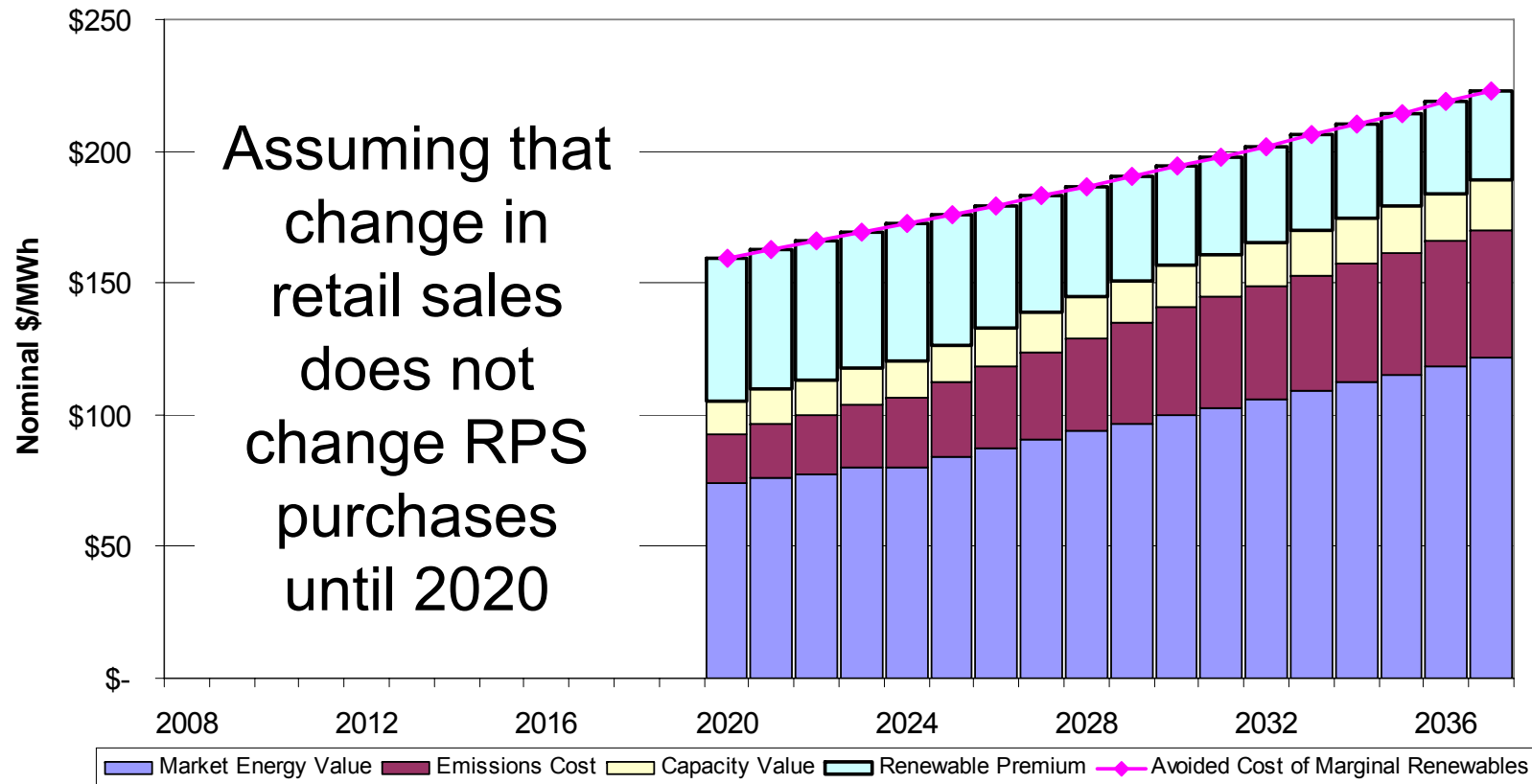
- Because NEM will reduce net retail sales in CA, there is also a benefit to the program in that it will reduce RPS requirements
- Model develops a levelized RPS Adder, which represents the additional benefit of avoided renewables purchases due to the reduction in retail sales
- The benefits of avoided RPS purchases do not begin until 2020, as it is assumed that CA will purchase renewables as fast as possible until then in order to achieve compliance with the 33% target



# Calculation of the RPS Adder

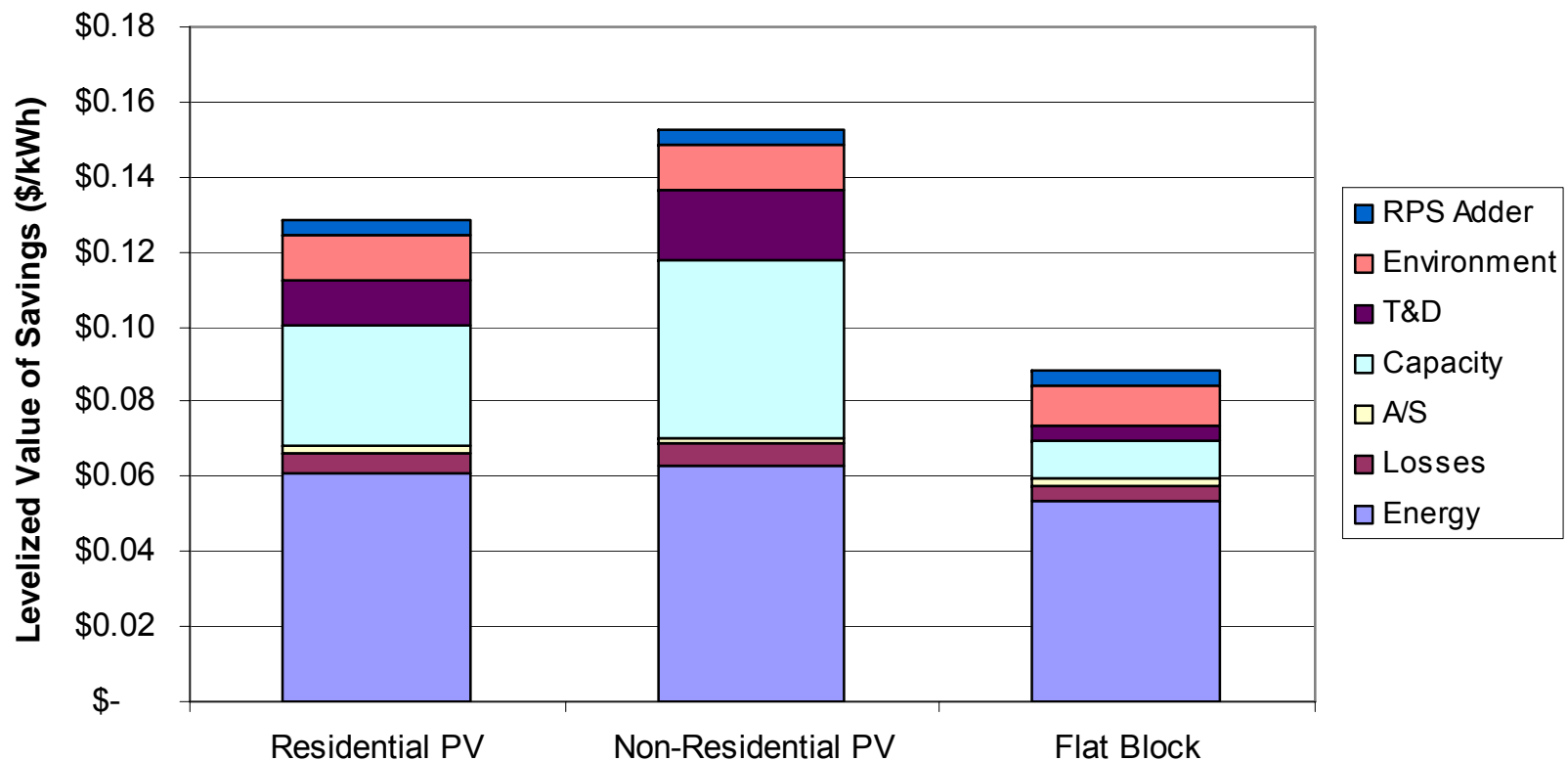
- RPS Premium is the incremental cost of procuring renewable resources
  - Marginal delivered cost of renewables, less the market energy and capacity value of those resources, less average CO<sub>2</sub> emissions of a conventional plant
- RPS Adder is equal to the RPS Premium multiplied by 33% (the RPS portfolio requirement)
- Assumptions for marginal renewable resource based E3's 33% model (33% Reference Case)
  - Based on renewable resource bundle in Fairmont, CA

# Calculation of the RPS Premium

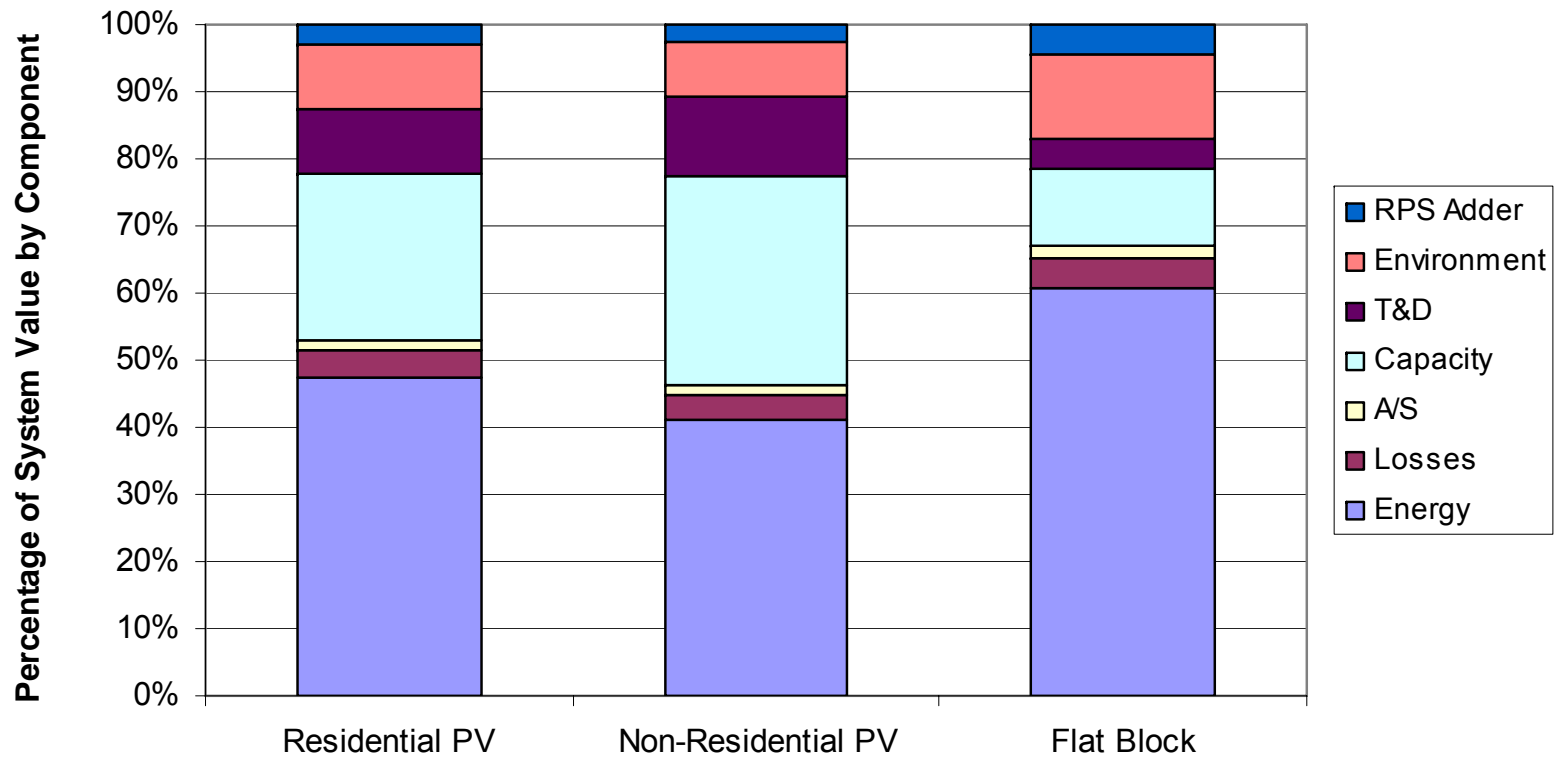


RPS Adder = 33% \* Levelized Premium = \$4/MWh

# Average Avoided Cost by Component for Two Sample PV Output Shapes (CZ3)



# Relative Share of Value



# Contact Information

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