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The Power of Concentration

Feed-In Tariff (FIT)

Making the RPS Real

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Comprehensive FIT Features

- Standard Must-Take Contract between developer and utility
  - Once a developer builds a FIT facility, the utility must interconnect it
- Predefined prices for targeted renewable energy technologies
  - Rates are cost-based and technology-differentiated
  - 20-year contract durations are always a developer option
  - Price is predictable from the online date through the contract duration
- FIT energy is bundled with all its attributes
  - Utility gets environmental attributes (RECs etc) with purchased energy
- FIT facilities are interconnected directly to the grid
  - No behind-the-meter interconnections
  - No energy production for onsite load and no net metering issues

Comprehensive FIT Benefits

- Simple, streamlined, and totally predictable
  - FITs work well for everyone: developers, investors, regulators, utilities, and ratepayers
  - The pricing knob provides the master control
  - Preempts utilities from rejecting projects that meet predetermined parameters
- The most effective policy mechanism worldwide for bringing renewable energy online and also the lowest cost mechanism
- Equal opportunity for all to maximize renewable energy
  - Any party can own a FIT facility
  - FIT facilities can be deployed on the same property as CSI/SGIP facilities
  - Property owners can maximize renewable energy beyond onsite loads and FITs can easily be deployed on leased and multi-unit properties
  - Preempts utilities from limiting deployments via demand charges etc

FITs Maximize the Market

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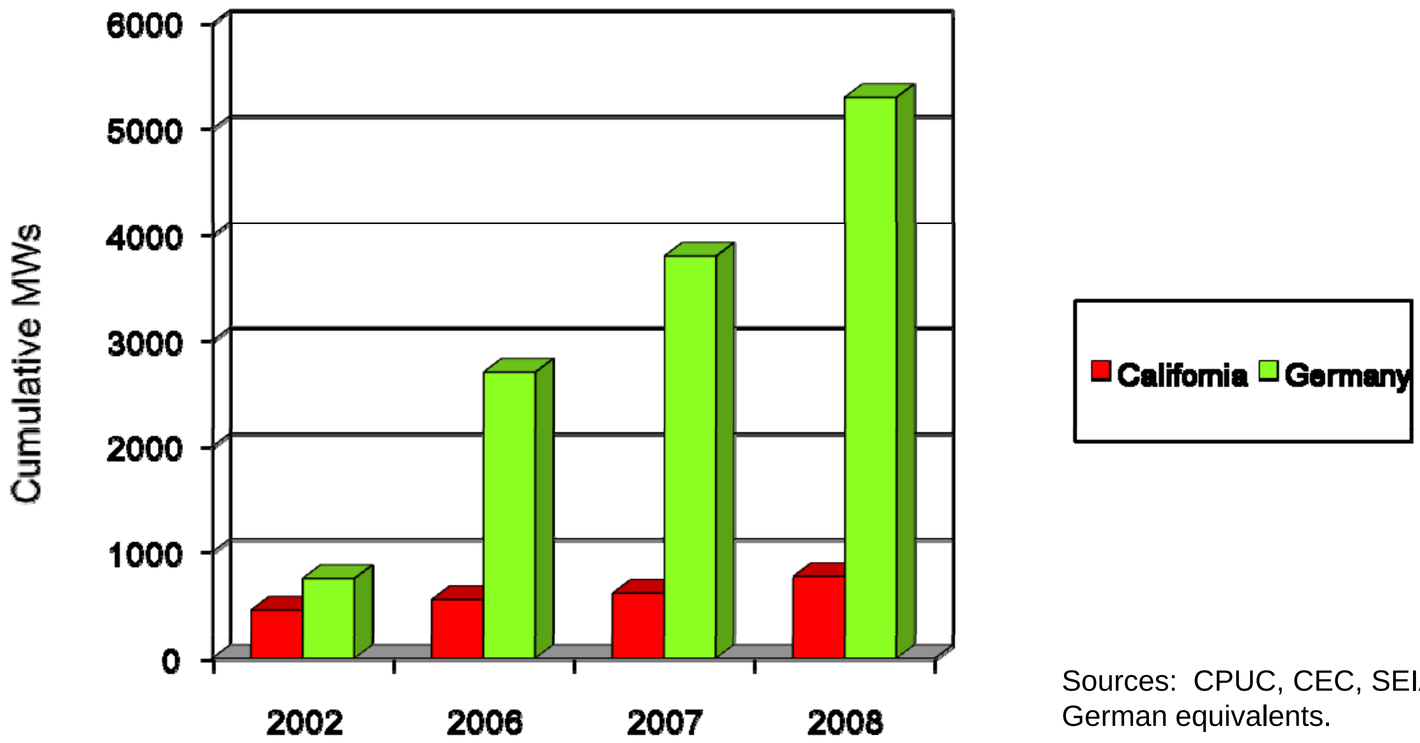
Solar Markets: German vs California (RPS + CSI + other)



Sources: CPUC, CEC, SEIA and German equivalents.

Germany added10 times more solar than California last year!

Even though California's solar resource is 50% better!!!

CEC: Comprehensive FIT Now

California Energy Commission

2008 IEPR Recommendations for Feed-in Tariffs

1. The CPUC should immediately implement a feed-in tariff program for all RPS-eligible generating facilities up to 20 MW in size. Such a program should include must-take provisions as well as cost-based technology-specific prices that generally decline over time and are not linked to the CPUC's market price referent.

2. The Energy Commission and CPUC should continue to evaluate feed-in tariffs for renewable projects larger than 20 MW using the information in the Energy Commission's report on feed-in tariffs expected to be completed in early 2009.

Official CEC recommendation, released 1 Dec 08

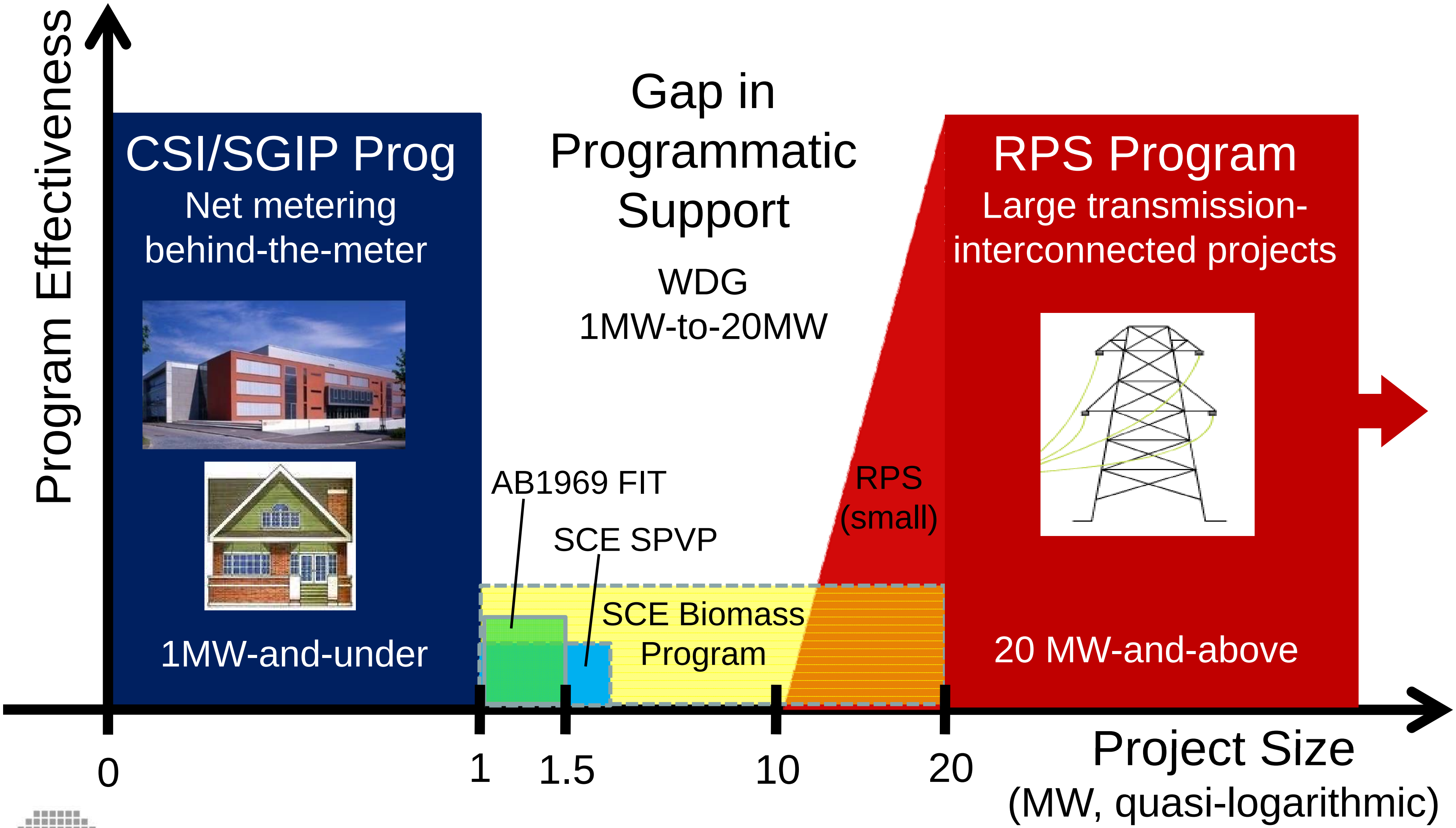
Urgent RPS Challenges

- 20% of retail electricity sales by 2010
  - It is not contracted energy that counts toward the requirement
  - Achieving 20% by 2010 will guide the way to 33% by 2020
  - California stuck at 12% for entire 7-year duration of its RPS program
- Transmission represents a 7-15 year delay to most proposed transmission-interconnected projects
- There is a significant programmatic gap in support for renewables in California
  - CSI/SGIP support 1MW-and-under, behind-the-meter
  - RPS is geared around large transmission-interconnected projects
  - No viable support for wholesale distribution-interconnected

20% by 2010

The most urgent RPS challenge is achieving 20% of sales by 2010

Programmatic Coverage Gap



WDG: The Big Opportunity

- WDG = Wholesale Distributed Generation
  - Wholesale (all energy sold to the utility)
  - 20MW-and-under
  - Distribution-interconnected (close-to-load, but not behind-the-meter)
- WDG provides significant Locational Benefits (LBs) value
  - On average in California, distribution-interconnected generation has a value boost of more than 35% over transmission-interconnected
    - Per detailed analysis from the CPUC-commissioned E3 Cost-Effectiveness Model
- Hundreds of GWs of WDG potential in California
  - RETI draft Phase 1B report identified 27.5GW of PV with significant constraints: Only PV considered, in 20MW-sized projects, co-located with distribution substations that had ample non-sensitive land available (assumes 160 acres to be required per project)

Hundreds of GWs of WDG potential in California alone

The REESA FIT Delivers

Comparison of currently proposed FIT legislation in California

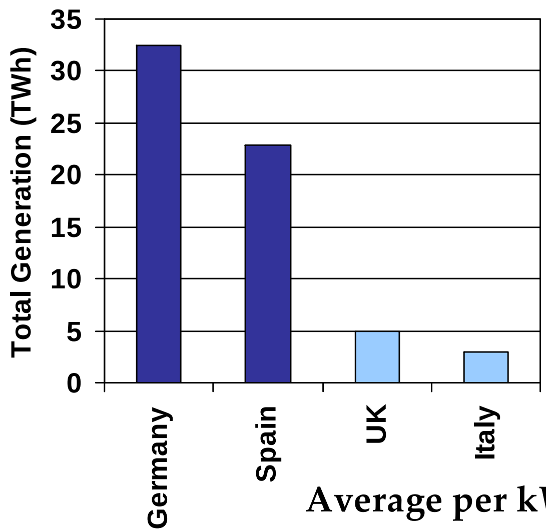
	REESA FIT	AB 1969 current	AB 1969 proposed	SB 32	AB 64
Standard Must-Take Contract	Yes	Yes	Yes	Yes	Yes
Capacity	20 MW and under	1.5 MW and under	20 MW and under	3 MW and under	5 MW and under
Pricing	Cost-based (cost of production plus reasonable profit)	MPR-based (avoided cost of a new 500MW natural gas plant)	MPR-based (avoided cost of a new 500MW natural gas plant)	MPR-based (avoided cost of a new 500MW natural gas plant)	MPR-based (avoided cost of a new 500MW natural gas plant)
Technology differentiation	Yes	No	No	No	No
Allowed Developers	Any party, including utilities	Utility customer	Utility customer	Utility customer	Utility customer
Environmental Attributes (RECs etc)	Bundled with the electricity	Bundled with the electricity	Bundled with the electricity	Bundled with the electricity	Bundled with the electricity
Program Cap	2% of demand, annually, by utility	500 MW	500 MW	500 MW	500 MW

The REESA FIT delivers for California and the renewable energy industry

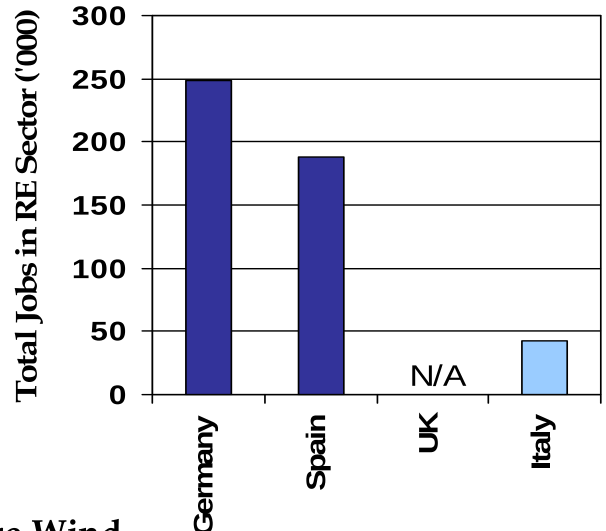
REESA = Renewable Energy & Economic Stimulus Act of 2009

FITs: Clearly Superior

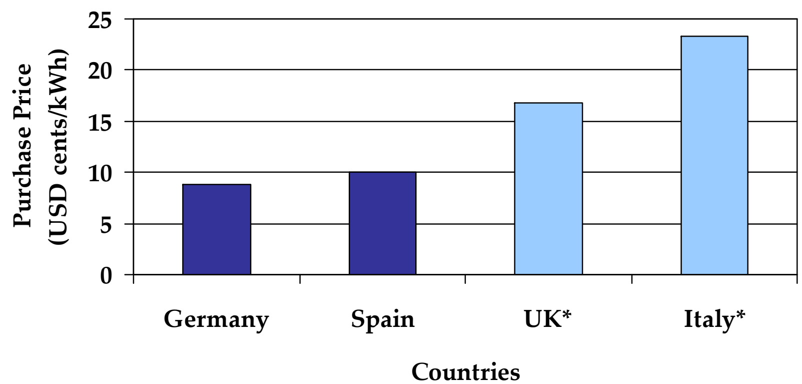
Total Generation from Wind Power (2006)



Total Jobs in RE Sector (2007)



Average per kWh Payment for Onshore Wind (2008)



* Electricity price + Tradable Green Certificate (i.e. REC)

Sources: NREL 2009; BMU 2008; EUROSTAT 2008; ISI, 2008; Fouquet, D. et al., 2008.

REESA FIT: Making the RPS Real

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The REESA FIT delivers 100% of the 33% RPS gap while increasing rates less 10%; a total cumulative impact far less than anticipated inflation

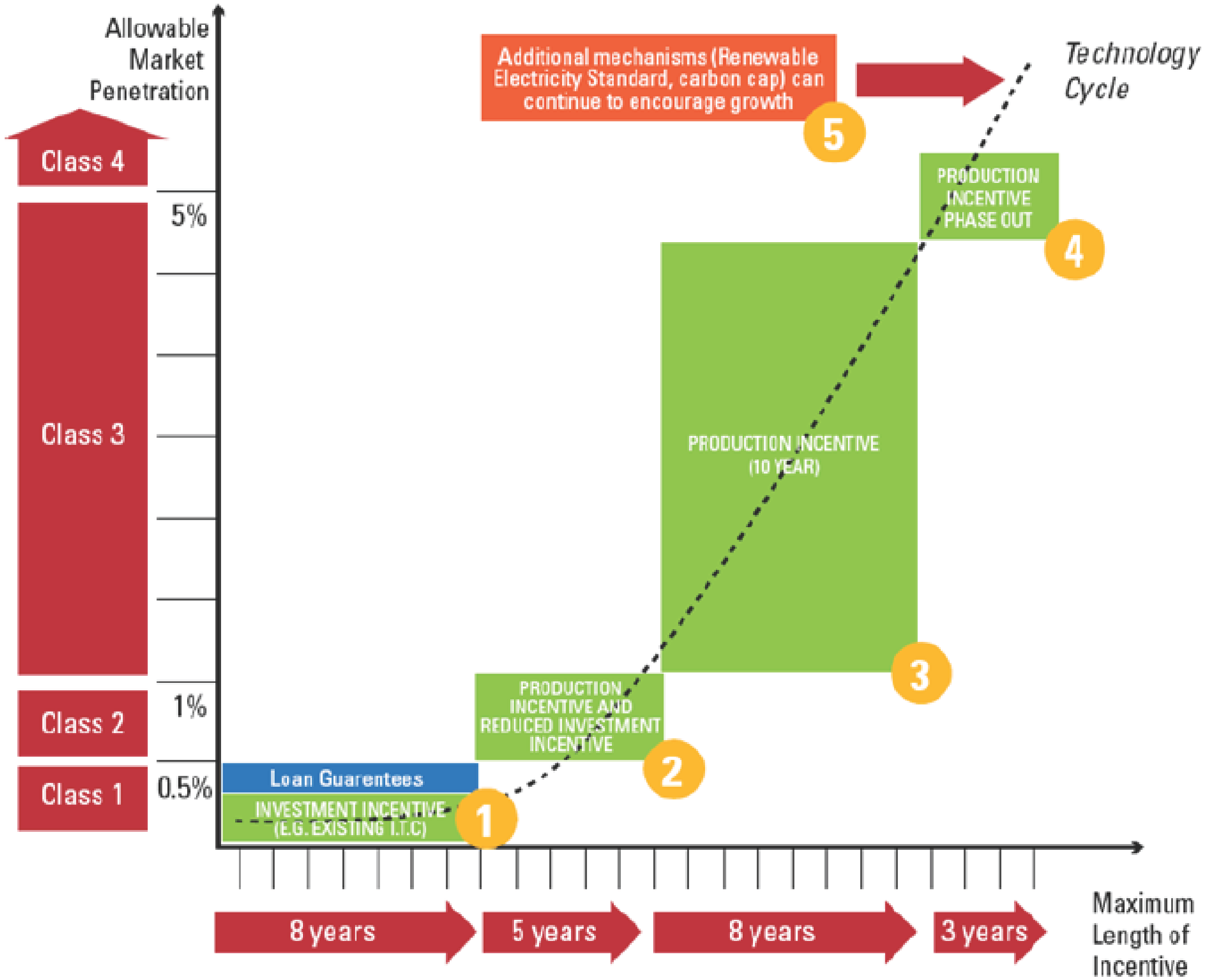
Year	Total CA Electric Energy (GWh)	FIT Rate ($/kWh)	Cumulative Limit	Quantity (GWh)	FIT Fulfillment of RPS	FIT Cost ($mil)	Avoided Cost ($/kWh)	Avoided Cost ($mil)	Net Cost ($mil)	Rates without FIT	Rates with FIT	Cumulative Total Rate Increase
2008	265,185	0.22	0%	-	0%	0	0.15	0	0	0.135	0.135	0.00%
2012	279,530	0.22	5%	13,977	5%	3,075	0.15	2,096	978	0.139	0.143	2.51%
2013	283,116	0.22	7%	19,818	7%	4,360	0.15	2,973	1,387	0.141	0.145	3.49%
2014	286,703	0.22	9%	25,803	9%	5,677	0.15	3,870	1,806	0.142	0.148	4.44%
2015	290,289	0.22	11%	31,932	11%	7,025	0.15	4,790	2,235	0.143	0.150	5.39%
2016	293,875	0.22	13%	38,204	13%	8,405	0.15	5,731	2,674	0.144	0.153	6.32%
2017	297,461	0.22	15%	44,619	15%	9,816	0.15	6,693	3,123	0.145	0.156	7.22%
2018	301,048	0.22	17%	51,178	17%	11,259	0.15	7,677	3,582	0.147	0.159	8.11%
2019	304,634	0.22	19%	57,880	19%	12,734	0.15	8,682	4,052	0.148	0.161	9.01%
2020	308,220	0.22	21%	64,726	21%	14,240	0.15	9,709	4,531	0.149	0.164	9.84%

The REESA FIT makes the RPS real by satisfying the entire 33% RPS while providing cumulative ratepayer savings!!!

Sources: E3 GHG Calculator; CPUC 2008 MPR.

Reference

Policy Evolution is Required



Policy mechanisms for facilitating renewable energy technologies as they mature, NRDC Feb09

Value boost of LBs to 2008 MPR

Value boost of Locational Benefits to MPR ($/MWh)
(20-Year MPR Starting in 2009)

Issue	Fixed	Variable	Total	Increase*	% Change	Cumulative
Adopted 2007 MPR	$27	$70	$97	NA	NA	NA
Proposed 2008 MPR with GreenVolts Locational Adjustments						
Avoided Distribution Line Losses (prima	$29	$73	$102	$5	5%	5%
Avoided Distribution Investment	$29	$89	$118	$16	17%	22%
Avoided Transmission Investment	$29	$102	$131	$13	13%	35%
Avoided Tranmission Congestion	(to be determined based on MRTU values)					

Notes:

1) Increase in T&D avoided costs is based upon average of E3 model values for Edison's service territory. Solar profile values range from $12.89 to $13.27 per MWh for Transmission, and from $9.79 to $23.84 per MWh for Distribution.

2) Project assumptions include lifespan from 2008 - 2027, 2.5% inflation, 8.93% discount rate, and 2008 $.

3) Avoided T&D are based on a solar photovoltaic (PV) output profile from a south-facing flat-plate PV system at a 38.5 degree tilt located in Sacramento, CA.

4) For SCE, primary voltages are 2kV to 50kV, and a QF interconnecting at primary voltage receives the primary WDAT loss factor, regardless of the specific location that it interconnects; as the loss factor is an average number over the entire primary distribution system. There is no calculation to determine exactly how a specific primary distribution loss compare to the average.

On average, in California, Distribution-interconnected generation is worth at least 35% more than Transmission-interconnected generation

Source: CPUC-commissioned E3 Cost-Effectiveness Model

Locational Benefits: Avoided T&D

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E3 Model T&D Values (Levelized 20-year in 2008$)

Utility	Division	Transmission + Distribution: Baseload Profile $/kW-year	Transmission + Distribution: Baseload Profile $/MWh	Transmission + Distribution: Solar Profile $/kW-year	Transmission + Distribution: Solar Profile $/MWh	Transmission: Baseload Profile $/kW-year	Transmission: Baseload Profile $/MWh	Transmission: Solar Profile $/kW-year	Transmission: Solar Profile $/MWh	Distribution: Baseload Profile $/kW-year	Distribution: Baseload Profile $/MWh	Distribution: Solar Profile $/kW-year	Distribution: Solar Profile $/MWh
PG&E	Central Coast	$46.07	$5.26	$35.70	$24.60	$1.55	$0.18	$1.20	$0.83	$44.51	$5.08	$34.50	$23.77
	De Anza	$58.67	$6.70	$46.95	$32.35	$1.55	$0.18	$1.24	$0.86	$57.11	$6.52	$45.71	$31.49
	Diablo	$55.62	$6.35	$44.51	$30.67	$1.55	$0.18	$1.24	$0.86	$54.06	$6.17	$43.27	$29.81
	East Bay	$11.57	$1.32	$8.97	$6.18	$1.55	$0.18	$1.20	$0.83	$10.02	$1.14	$7.77	$5.35
	Fresno	$48.24	$5.51	$37.08	$25.55	$1.55	$0.18	$1.19	$0.82	$46.68	$5.33	$35.89	$24.72
	Kern	$30.87	$3.52	$23.73	$16.35	$1.55	$0.18	$1.19	$0.82	$29.32	$3.35	$22.54	$15.53
	Los Padres	$46.82	$5.34	$37.47	$25.81	$1.55	$0.18	$1.24	$0.86	$45.26	$5.17	$36.23	$24.96
	Mission	$70.36	$8.03	$54.53	$37.57	$1.55	$0.18	$1.20	$0.83	$68.80	$7.85	$53.32	$36.74
	North Bay	$47.46	$5.42	$36.78	$25.34	$1.55	$0.18	$1.21	$0.83	$45.90	$5.24	$35.57	$24.51
	North Coast	$64.43	$7.35	$40.41	$27.84	$1.55	$0.18	$0.97	$0.67	$62.87	$7.18	$39.43	$27.17
	North Valley	$80.30	$9.17	$63.33	$43.63	$1.55	$0.18	$1.23	$0.84	$78.74	$8.99	$62.10	$42.78
	Peninsula	$20.90	$2.39	$16.19	$11.16	$1.55	$0.18	$1.20	$0.83	$19.34	$2.21	$14.99	$10.33
	Sacramento	$60.93	$6.96	$48.05	$33.11	$1.55	$0.18	$1.23	$0.84	$59.37	$6.78	$46.83	$32.28
	San Francisco	$16.89	$1.93	$13.09	$9.02	$1.55	$0.18	$1.20	$0.83	$15.34	$1.75	$11.89	$8.19
	San Jose	$44.65	$5.10	$35.74	$24.62	$1.55	$0.18	$1.24	$0.86	$43.10	$4.92	$34.49	$23.76
	Sierra	$66.84	$7.63	$52.71	$36.32	$1.55	$0.18	$1.23	$0.84	$65.29	$7.45	$51.49	$35.47
	Stockton	$69.90	$7.98	$55.94	$38.54	$1.55	$0.18	$1.24	$0.86	$68.34	$7.80	$54.69	$37.68
	Yosemite	$42.73	$4.88	$34.20	$23.56	$1.55	$0.18	$1.24	$0.86	$41.18	$4.70	$32.96	$22.70
SCE	Dominguez Hills	$45.91	$5.24	$32.93	$22.69	$26.09	$2.98	$18.71	$12.89	$19.82	$2.26	$14.21	$9.79
	Foothills	$59.90	$6.84	$42.96	$29.59	$26.09	$2.98	$18.71	$12.89	$33.80	$3.86	$24.24	$16.70
	Santa Ana	$55.19	$6.30	$39.58	$27.27	$26.09	$2.98	$18.71	$12.89	$29.10	$3.32	$20.87	$14.38
	SCE Rural	$72.95	$8.33	$53.87	$37.11	$26.09	$2.98	$19.27	$13.27	$46.86	$5.35	$34.60	$23.84
	Ventura	$57.57	$6.57	$41.29	$28.45	$26.09	$2.98	$18.71	$12.89	$31.48	$3.59	$22.58	$15.56
SDG&E	SDG&E	$114.15	$13.03	$84.35	$58.11	$13.84	$1.58	$10.23	$7.05	$100.31	$11.45	$74.12	$51.07

Note: assumes 2008 - 2027 project lifespan, 2.5% inflation, 8.93% discount rate, and 2008 $

Source: CPUC-commissioned E3 Cost-Effectiveness Model

Example MPR & TOD

2007 MPR
(CPUC)

Adopted 2007 Market Price Referents[1] (Nominal - dollars/kWh)			
Resource Type	10-Year	15-Year	20-Year
2008 Baseload MPR	0.09271	0.09383	0.09572
2009 Baseload MPR	0.09302	0.09475	0.09696
2010 Baseload MPR	0.09357	0.09591	0.09840
2011 Baseload MPR	0.09412	0.09696	0.09969
2012 Baseload MPR	0.09518	0.09844	0.10139
2013 Baseload MPR	0.09605	0.09965	0.10275
2014 Baseload MPR	0.09722	0.10107	0.10430
2015 Baseload MPR	0.09872	0.10274	0.10606
2016 Baseload MPR	0.10053	0.10466	0.10804
2017 Baseload MPR	0.10269	0.10685	0.11143
2018 Baseload MPR	0.10478	0.11016	0.11489
2019 Baseload MPR	0.10818	0.11370	0.11720
2020 Baseload MPR	0.11172	0.11603	0.11954

[1] Note: using 2008 as the base year, Staff calculates MPRs for 2008-2020 that reflect different project online dates.

2007 TOD
(SCE)

Time of Use Periods ("TOU Periods")

TOU Period	*Summer Jun 1st – Sep 30th*	*Winter Oct 1st – May 31st*	*Applicable Days*
On-Peak	Noon – 6:00 p.m.	Not Applicable.	Weekdays except Holidays.
Mid-Peak	8:00 a.m. – Noon	8:00 a.m. - 9:00 p.m.	Weekdays except Holidays.
	6:00 p.m. – 11:00 p.m.		Weekdays except Holidays.
Off-Peak	11:00 p.m. – 8:00 a.m.	6:00 a.m. – 8:00 a.m.	Weekdays except Holidays.
		9:00 p.m. – Midnight	Weekdays except Holidays.
	Midnight – Midnight	6:00 a.m. – Midnight	Weekends and Holidays
Super-Off-Peak	Not Applicable.	Midnight – 6:00 a.m.	Weekdays, Weekends and Holidays

2007 MPR Formula

Table 5 – *2007 MPR in Simple Terms (20-year contract starting in 2008)*

Line	Component	Cost	Calculation
1	Levelized Gas Price	8.64 / MMBtu	
2	Effective Heat Rate	6,964 Btu/kWh	
3	Fuel Cost	$60.19 / MWh	1 x 2
4	Variable O&M	$2.87 / MWh	
5	Line Loss Factor	98.0%	
6	Variable Cost at Load Center	$64.33 per MWh	(3+4)/5
7	Collateral Requirement	$0.34 per MWh	
8	Greenhouse Gas Mitigation	$4.26 per MWh	
9	Total Variable Cost (including externalities)	**$68.94 per MWh**	6+7+8
10	Fixed Cost	**$26.79 per MWh**	
11	Total MPR Price	**$95.73 per MWh**	9+10

2007 MPR = ~$95 per MWh x TOD factor (~1.4 for GV profile on SCE)