Approved: March 24, 2009
Date

MINUTES OF THE HOUSE ENERGY AND UTILITIES COMMITTEE

The meeting began at 9:00 a.m. on March 3, 2009, in the seminar room at the Department of Schools Building.

All members were present except:
Representative Gail Finney- excused
Representative Dan Johnson- excused
Representative Annie Kuether- excused
Representative Margaret Long- excused
Representative Tom Moxley- excused
Representative Don Myers- excused
Representative Connie O'Brien- excused
Representative Rob Olson- excused
Representative Richard Proehl- excused
Representative Tom Sloan- excused
Representative Josh Svaty- excused
Representative Milack Talia- excused

Committee staff present:
Melissa Doeblin, Office of the Revisor of Statutes
Mary Galligan, Kansas Legislative Research Department
Cindy Lash, Kansas Legislative Research Department
Renae Hansen, Committee Assistant

The committee attended portions of "The Solar Roundtable" sponsored by The Kansas Energy Programs division of the Kansas Corporation Commission. Short biographies of the individual speakers (Attachment 1) were included.

The Economics of Solar Power

Peter Lorenz, President, Quanta Renewable Energy Services, (Attachment 2), presented a power-point entitled, "The Economics of Solar Power". Mr. Lorenz spoke about the United States' and the world market for many different aspects of solar energy for the current perspective and future outlook. Additionally an article published in The McKinsey Quarterly, June 2008, co-authored by Peter Lorenz, Dicken Pinner, and Thomas Seitz, entitled, "The economics of solar power" (Attachment 3) was included as a resource for conferrees.

Included also was a Lawrence Berkeley national Laboratory publication entitled, "Tracking the Sun, The Installed Cost of Photovoltaics in the U.S. from 1998-2007", (Attachment 4).

Also provided in the information was a Chart on Photovoltaic Electrical Energy Production in Kansas (Attachment 5).

Regulatory Issues with Solar Power

Jason Keyes, Partner, Keyes & Fox, LLP, Seattle, Washington, spoke to the committee about an update on regulatory issues concerning solar energy. He noted a website with information on tracking existing state and local procedures at www.desireusa.org . He presented a power point (Attachment 6) that talked about the regulatory issues.

The next meeting is scheduled for March 4, 2009.

Committee members left the roundtable at 10:30 a.m. to be present at the House session on the floor of the House chambers.

Dr. Ward Jewell
Professor of Electrical and Computer Engineering
Wichita State University

Dr. Jewell, professor of electrical and computer engineering, and IEEE Fellow, conducts research in power systems, power quality, distributed generation, renewable resources and distance learning. His current activities in the area of power quality include power quality troubleshooting, power system design to Dr. Ward T. Jewell, better serve loads, disturbance and susceptibility testing of loads, and load design to decrease disturbances and susceptibility.

Power quality research is performed through the WSU Power Quality Lab, which provides field and laboratory equipment, computer analysis, and simulation capabilities.

Roger Taylor
U.S. Department of Energy,
National Renewable Energy Laboratory (NREL)

Roger Taylor is a member of the State, Local, and Tribal Integrated Applications Group in the Strategic Energy Analysis and Applications Center. Mr. Taylor will give us an overview of current and near-term solar technology with an emphasis on photovoltaic technologies. Mr. Taylor has a B.S. degree in Physics from Colorado College and an M.S. in Mechanical Engineering from the University of Arizona.

Colin Murchie
Director, Government Affairs
SunEdison, LLC

Colin Murchie is Director, Government Affairs for SunEdison, LLC, the nation's largest provider of solar energy services. In this position, he leads SunEdison's legislative and regulatory advocacy in Mid-Atlantic and some Midwestern states, with a particular focus on interconnection, net metering, incentives, and rate design issues. Previously, Mr. Murchie was Director of Government Affairs at the Solar Energy Industries Association in Washington, DC.

Peter Lorenz
Associate Principle, McKinsey and Company

Peter joined the Houston office of McKinsey and Company in 2001 where he is a leader of McKinsey's North American Electric Power and Natural Gas practice. He has served power companies on strategic, operational, and commercial issues. Peter is currently developing go-to-market strategies for a major Solar power company and leading a global knowledge effort on the future of Solar power.

Prior to joining McKinsey, Peter worked for Royal Dutch Shell in London on several finance assignments. In the late 90's, Peter was a member of Shell's global Solar Management team and instrumental in establishing Shell's global PV business.

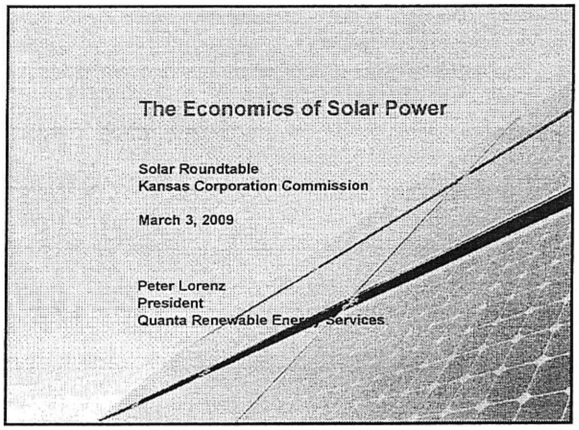
Peter has an MBA from Harvard Business School and a BA in European Business Administration from the University of Reutlingen, Germany and Middlesex University, London.

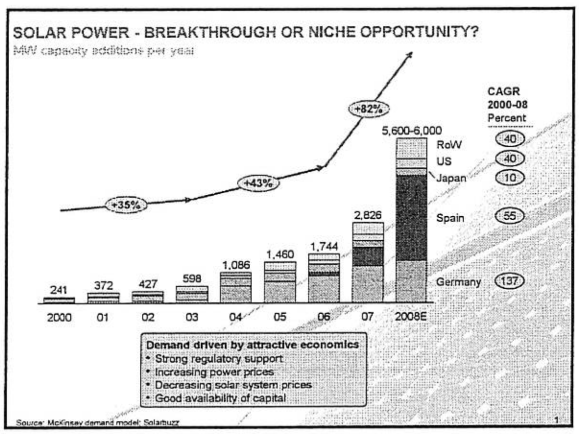
Jason Keyes
Partner
Keyes & Fox, LLP
Seattle, Washington

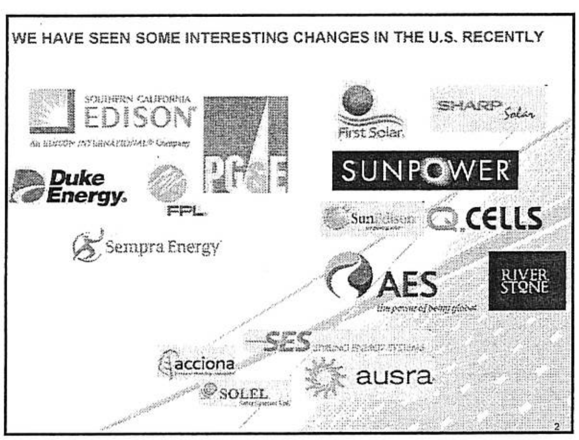
Jason Keyes co-founded the two-man law firm of Keyes & Fox, LLP in July, 2008 to focus on distributed generation law. The new firm's primary client is the Interstate Renewable Energy Council, which the firm represents in state utility commission rulemakings related to net metering and interconnection procedures.

Prior to this move, Jason worked on solar project development at the law firm of Wilson Sonsini Goodrich & Rosati and before that, he represented a major utility and worked on wind project development at the law firm of Stoel Rives. Prior to law school, Jason managed government contracts and business development for eight years at JX Crystals Inc., a pioneer in the field of high-concentration PV and thermophotovoltaics. And in the early 90's, Jason ran the electric vehicle program and helped develop the integrated resource plan and the demand forecast at Puget Power during his three years at that electric utility.

In his free time, Jason enjoys being with his wife and three daughters, skiing and hiking. He has completed more than half of the Pacific Crest Trail (from Mexico to Canada).







HOUSE ENERGY AND UTILITIES
DATE: 3/3/2009
ATTACHMENT 2-1

TODAY'S DISCUSSION

- **Solar technologies and their evolution**
- Demand growth outlook
- Perspectives on solar following the economic crisis

3

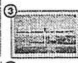
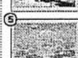
TWO KEY SOLAR TECHNOLOGIES EXIST

	Photovoltaics (PV)	Concentrated Solar Power (CSP)
		
Key characteristics	• Uses light-absorbing material to generate current • High modularity (1 kW - 50 MW) • Uses direct and indirect sunlight – suitable for almost all locations • Incentives widely available • Mainly used as distributed power, some incentives encourage large solar farms	• Uses mirrors to generate steam which powers turbine • Low modularity (20 - 300 MW) • Only uses direct sunlight – specific site requirements • Incentives limited to few countries • Central power only limited by adequate locations and transmission access
Global capacity GW, 2007	~ 10	~ 0.5

Source: McKinsey analysis; EPIA; MarketBuzz

4

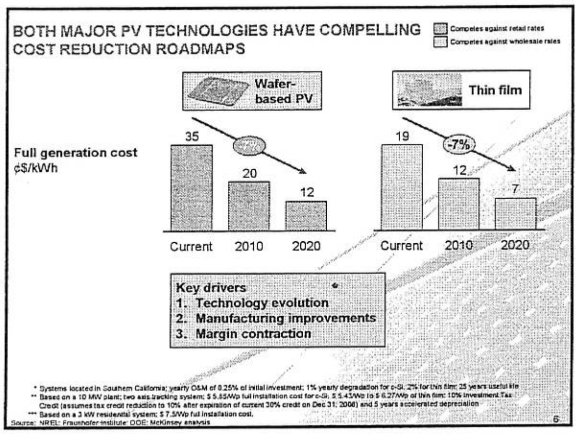
THESE HAVE SEVERAL SUB-TECHNOLOGIES

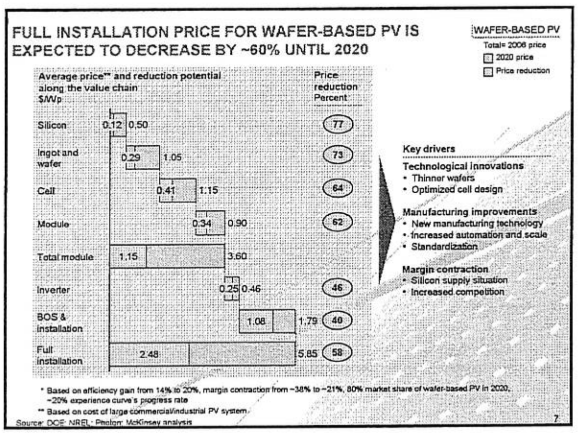
	Key technologies	Sub technologies	Description	Development
Photo Voltaics (PV)	①  Wafer-based PV	• Mono-crystalline • Poly-crystalline	• Uses solar cells combined to modules to generate electricity	Commercial
	②  Thin film	• Amorphous silicon (a -Si) • Cadmium telluride (CdTe) • Copper indium gallium selenide (CIGS)	• Thin layer of glass, steel, and semiconductor material used to convert light directly into electricity	Commercial
		• Nano • Organic dye	• Mixture of flexible polymer substrates with nano materials • Flexible PV using plastic as substrate	Laboratory phase
	③  Con-cen-trating PV	• N/A	• Mirrors used to concentrate light onto cells to increase effectiveness	Pilot
Solar thermal	④  Para-bolic trough	• Without storage or hybrid fossil • With storage • With storage and hybrid fossil	• Parabolic mirrors concentrate sunlight on a tube filled with heat transfer fluid • Heated fluid powers steam turbine	Commercial
	⑤  Dish-stirling	• N/A	• Solar energy converted to heat in a dish collector drives stirling engine, a heat engine that does not require water supply	Pilot
	⑥  Power tower	• Without storage or hybrid fossil • With storage • With storage and hybrid fossil	• Sun-tracking mirrors focus sunlight on a receiver at the top of a tower which heats water to produce electricity	Pilot

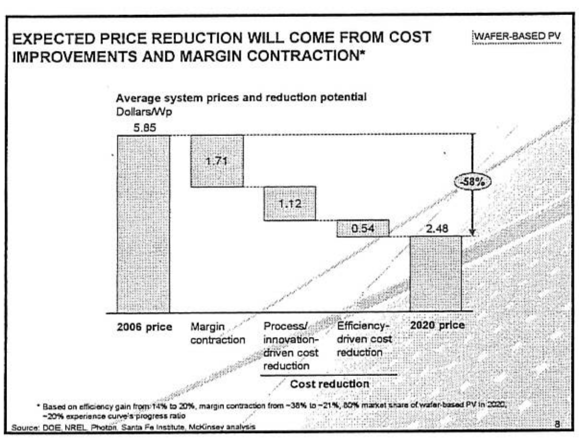
Source: Research reports; Wikipedia; team analysis

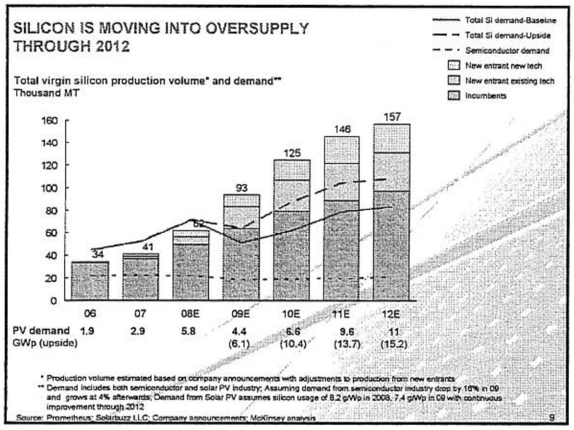
5

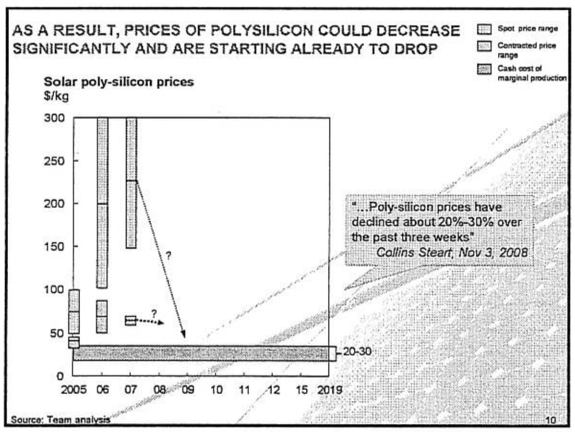
2-2

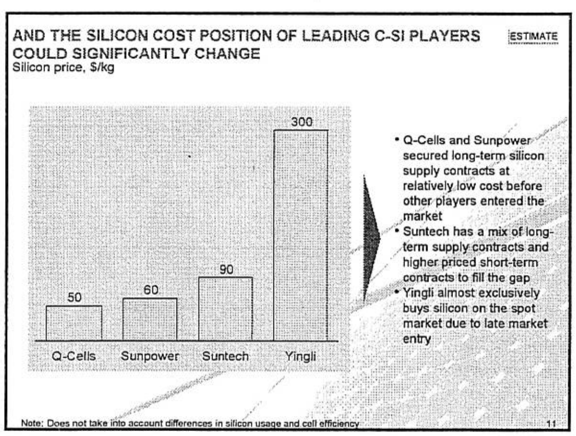

BOTH MAJOR PV TECHNOLOGIES HAVE COMPELLING COST REDUCTION ROADMAPS
Competes against retail rates
Competes against wholesale rates
Wafer-based PV
Thin film
Full generation cost
¢$/kWh
35
20
12
19
-7%
12
7
Current
2010
2020
Current
2010
2020
Key drivers
1. Technology evolution
2. Manufacturing improvements
3. Margin contraction
* Systems located in Southern California; yearly O&M of 0.25% of initial investment; 1% yearly degradation for c-Si, 2% for thin film; 25 years useful life
** Based on a 10 MW plant; two axis tracking system; $ 5.85/Wp full installation cost for c-Si; $ 5.43/Wp to $ 6.27/Wp of thin film; 10% Investment Tax Credit (assumes tax credit reduction to 10% after expiration of current 30% credit on Dec 31, 2008) and 5 years accelerated depreciation
*** Based on a 3 kW residential system; $ 7.5/Wp full installation cost.
Source: NREL; Fraunhofer-Institute; DOE; McKinsey analysis
6


FULL INSTALLATION PRICE FOR WAFER-BASED PV IS EXPECTED TO DECREASE BY ~60% UNTIL 2020
WAFER-BASED PV
Total= 2006 price
2020 price
Price reduction
Average price** and reduction potential along the value chain
$/Wp
Price reduction
Percent
Silicon 0.12 0.50 77
Ingot and wafer 0.29 1.05 73
Cell 0.41 1.15 64
Module 0.34 0.90 62
Total module 1.15 3.60
Inverter 0.25 0.46 46
BOS & installation 1.08 1.79 40
Full installation 2.48 5.85 58
Key drivers
Technological innovations
• Thinner wafers
• Optimized cell design
Manufacturing improvements
• New manufacturing technology
• Increased automation and scale
• Standardization
Margin contraction
• Silicon supply situation
• Increased competition
* Based on efficiency gain from 14% to 20%, margin contraction from ~38% to ~21%, 80% market share of wafer-based PV in 2020, ~20% experience curve's progress rate
** Based on cost of large commercial/industrial PV system
Source: DOE; NREL; Photon; McKinsey analysis
7

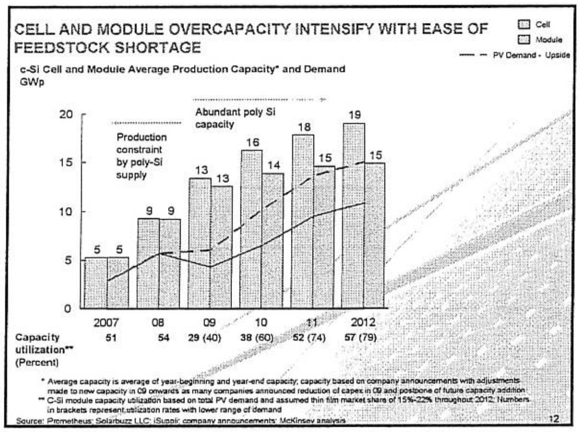

EXPECTED PRICE REDUCTION WILL COME FROM COST IMPROVEMENTS AND MARGIN CONTRACTION*
WAFER-BASED PV
Average system prices and reduction potential
Dollars/Wp
5.85
1.71
1.12
0.54
2.48
-58%
2006 price
Margin contraction
Process/innovation-driven cost reduction
Efficiency-driven cost reduction
2020 price
Cost reduction
* Based on efficiency gain from 14% to 20%, margin contraction from ~38% to ~21%, 80% market share of wafer-based PV in 2020, ~20% experience curve's progress ratio
Source: DOE, NREL, Photon, Santa Fe Institute, McKinsey analysis
8

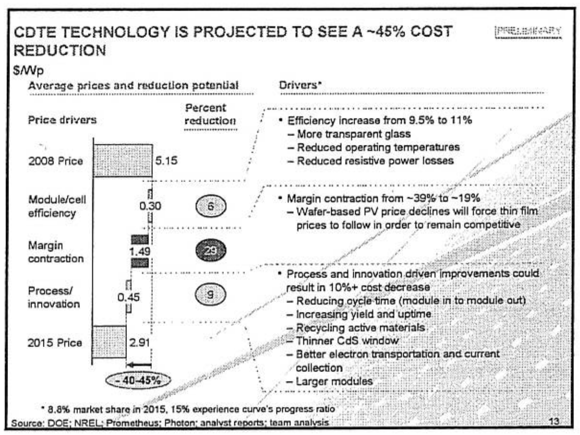

SILICON IS MOVING INTO OVERSUPPLY THROUGH 2012
Total Si demand-Baseline
Total Si demand-Upside
Semiconductor demand
New entrant new tech
New entrant existing tech
Incumbents
Total virgin silicon production volume* and demand**
Thousand MT
160
140
120
100
80
60
40
20
0
34
41
62
93
125
146
157
06
07
08E
09E
10E
11E
12E
PV demand 1.9 2.9 5.8 4.4 6.6 9.6 11
GWp (upside) (6.1) (10.4) (13.7) (15.2)
* Production volume estimated based on company announcements with adjustments to production from new entrants
** Demand includes both semiconductor and solar PV industry; Assuming demand from semiconductor industry drop by 16% in 09 and grows at 4% afterwards; Demand from Solar PV assumes silicon usage of 8.2 g/Wp in 2008, 7.4 g/Wp in 09 with continuous improvement through 2012
Source: Prometheus; Solarbuzz LLC; Company announcements; McKinsey analysis
9

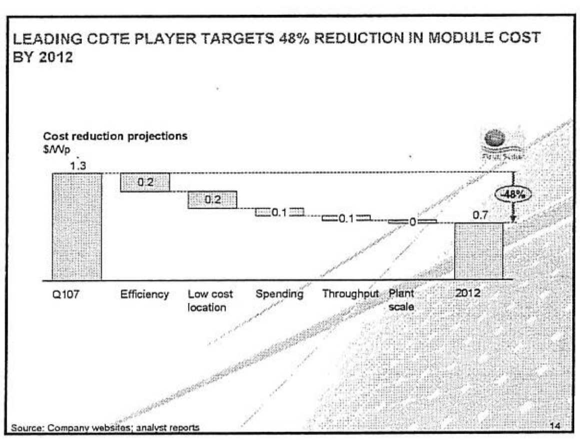

AS A RESULT, PRICES OF POLYSILICON COULD DECREASE SIGNIFICANTLY AND ARE STARTING ALREADY TO DROP
Spot price range
Contracted price range
Cash cost of marginal production
Solar poly-silicon prices
$/kg
300
250
200
150
100
50
0
?
?
20-30
2005 06 07 08 09 10 11 12 15 2019
"...Poly-silicon prices have declined about 20%-30% over the past three weeks"
Collins Steart, Nov 3, 2008
Source: Team analysis
10

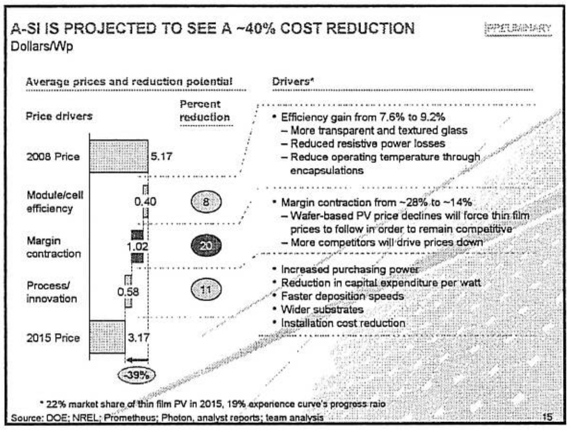

AND THE SILICON COST POSITION OF LEADING C-SI PLAYERS COULD SIGNIFICANTLY CHANGE
ESTIMATE
Silicon price, $/kg
50
60
90
300
Q-Cells
Sunpower
Suntech
Yingli
• Q-Cells and Sunpower secured long-term silicon supply contracts at relatively low cost before other players entered the market
• Suntech has a mix of long-term supply contracts and higher priced short-term contracts to fill the gap
• Yingli almost exclusively buys silicon on the spot market due to late market entry
Note: Does not take into account differences in silicon usage and cell efficiency
11

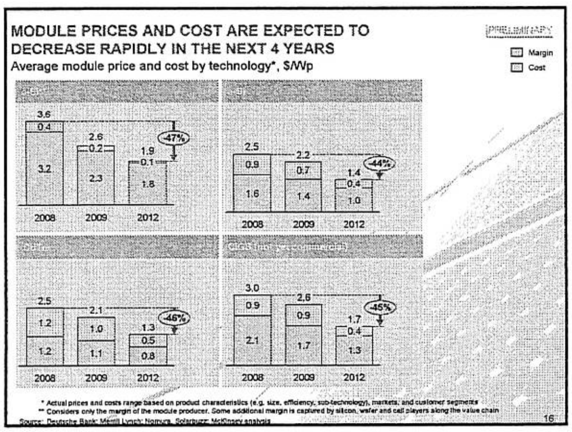
2-4

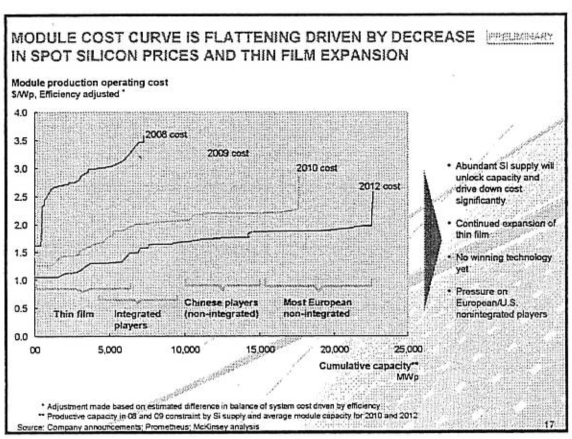

CELL AND MODULE OVERCAPACITY INTENSIFY WITH EASE OF FEEDSTOCK SHORTAGE
Cell
Module
PV Demand - Upside
c-Si Cell and Module Average Production Capacity* and Demand
GWp
20
15
10
5
0
Production constraint by poly-Si supply
Abundant poly Si capacity
5 5
9 9
13 13
16 14
18 15
19 15
2007
08
09
10
11
2012
Capacity utilization** (Percent)
51
54
29 (40)
38 (60)
52 (74)
57 (79)
* Average capacity is average of year-beginning and year-end capacity; capacity based on company announcements with adjustments made to new capacity in 09 onwards as many companies announced reduction of capex in 09 and postpone of future capacity addition
** C-Si module capacity utilization based on total PV demand and assumed thin film market share of 15%-22% throughout 2012; Numbers in brackets represent utilization rates with lower range of demand
Source: Prometheus; Solarbuzz LLC; iSuppli; company announcements; McKinsey analysis
12


CDTE TECHNOLOGY IS PROJECTED TO SEE A ~45% COST REDUCTION
PRELIMINARY
$/Wp
Average prices and reduction potential
Drivers*
Price drivers
Percent reduction
2008 Price
5.15
Module/cell efficiency
0.30
6
Margin contraction
1.49
29
Process/ innovation
0.45
9
2015 Price
2.91
- 40-45%
• Efficiency increase from 9.5% to 11%
– More transparent glass
– Reduced operating temperatures
– Reduced resistive power losses
• Margin contraction from ~39% to ~19%
– Wafer-based PV price declines will force thin film prices to follow in order to remain competitive
• Process and innovation driven improvements could result in 10%+ cost decrease
– Reducing cycle time (module in to module out)
– Increasing yield and uptime
– Recycling active materials
– Thinner CdS window
– Better electron transportation and current collection
– Larger modules
* 8.8% market share in 2015, 15% experience curve's progress ratio
Source: DOE; NREL; Prometheus; Photon; analyst reports; team analysis
13


LEADING CDTE PLAYER TARGETS 48% REDUCTION IN MODULE COST BY 2012
Cost reduction projections
$/Wp
1.3
0.2
0.2
0.1
0.1
0
0.7
-48%
Q107
Efficiency
Low cost location
Spending
Throughput
Plant scale
2012
Source: Company websites; analyst reports
14


A-SI IS PROJECTED TO SEE A ~40% COST REDUCTION
PRELIMINARY
Dollars/Wp
Average prices and reduction potential
Drivers*
Price drivers
Percent reduction
2008 Price
5.17
Module/cell efficiency
0.40
8
Margin contraction
1.02
20
Process/ innovation
0.58
11
2015 Price
3.17
-39%
• Efficiency gain from 7.6% to 9.2%
– More transparent and textured glass
– Reduced resistive power losses
– Reduce operating temperature through encapsulations
• Margin contraction from ~28% to ~14%
– Wafer-based PV price declines will force thin film prices to follow in order to remain competitive
– More competitors will drive prices down
• Increased purchasing power
• Reduction in capital expenditure per watt
• Faster deposition speeds
• Wider substrates
• Installation cost reduction
* 22% market share of thin film PV in 2015, 19% experience curve's progress raio
Source: DOE; NREL; Prometheus; Photon, analyst reports; team analysis
15


MODULE PRICES AND COST ARE EXPECTED TO DECREASE RAPIDLY IN THE NEXT 4 YEARS
Average module price and cost by technology*, $/Wp
Margin
Cost
3.6
0.4
3.2
2.6
0.2
2.3
1.9
0.1
1.8
-47%
2008
2009
2012
2.5
0.9
1.6
2.2
0.7
1.4
1.4
0.4
1.0
-44%
2008
2009
2012
2.5
1.2
1.2
2.1
1.0
1.1
1.3
0.5
0.8
-46%
2008
2009
2012
3.0
0.9
2.1
2.6
0.9
1.7
1.7
0.4
1.3
-45%
2008
2009
2012
* Actual prices and costs range based on product characteristics (e.g. size, efficiency, sub-technology), markets, and customer segments
** Considers only the margin of the module producer. Some additional margin is captured by silicon, wafer and cell players along the value chain
Source: Deutsche Bank; Merrill Lynch; Nomura, Solarbuzz; McKinsey analysis
16


MODULE COST CURVE IS FLATTENING DRIVEN BY DECREASE IN SPOT SILICON PRICES AND THIN FILM EXPANSION
PRELIMINARY
Module production operating cost
$/Wp, Efficiency adjusted *
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2008 cost
2009 cost
2010 cost
2012 cost
Thin film
Integrated players
Chinese players (non-integrated)
Most European non-integrated
00
5,000
10,000
15,000
20,000
25,000
Cumulative capacity** MWp
• Abundant SI supply will unlock capacity and drive down cost significantly
• Continued expansion of thin film
• No winning technology yet
• Pressure on European/U.S. nonintegrated players
* Adjustment made based on estimated difference in balance of system cost driven by efficiency
** Productive capacity in 08 and 09 constraint by Si supply and average module capacity for 2010 and 2012
Source: Company announcements; Prometheus; McKinsey analysis
17

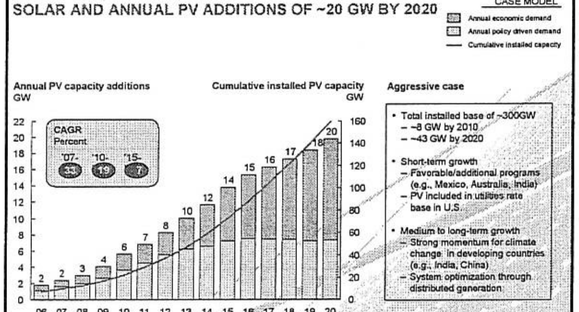
TODAY'S DISCUSSION

- Solar technologies and their evolution
- Demand growth outlook
- Perspectives on solar following the economic crisis

18

WE EXPECT TOTAL INSTALLED BASE OF 160 GW FOR SOLAR AND ANNUAL PV ADDITIONS OF ~20 GW BY 2020

McKINSEY BASE CASE MODEL



Aggressive case

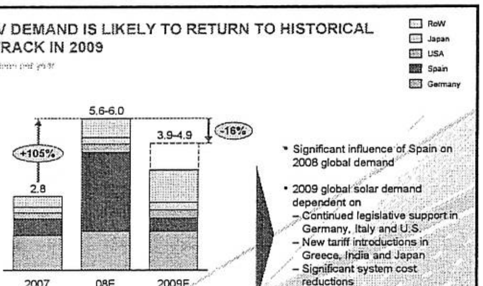
- Total installed base of ~300GW
  - ~8 GW by 2010
  - ~43 GW by 2020
- Short-term growth
  - Favorable/additional programs (e.g., Mexico, Australia, India)
  - PV included in utilities rate base in U.S.
- Medium to long-term growth
  - Strong momentum for climate change in developing countries (e.g., India, China)
  - System optimization through distributed generation

Source: McKinsey proprietary demand model

19

GLOBAL PV DEMAND IS LIKELY TO RETURN TO HISTORICAL GROWTH TRACK IN 2009

GW capacity additions per year

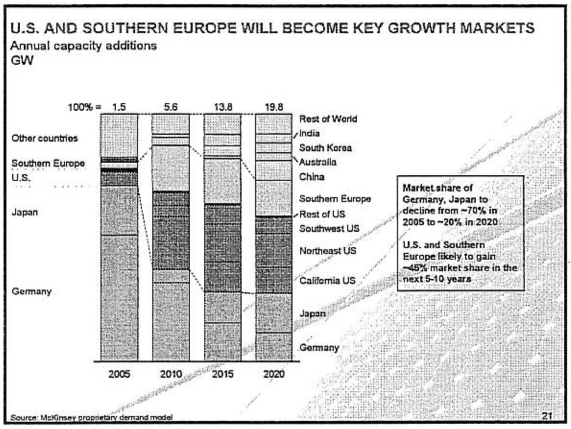


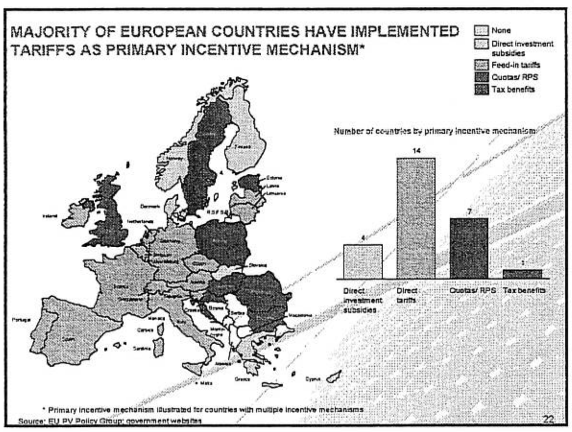
	2007	08E	2009E
YoY growth Percent	62	105	-24
YoY growth (excl. Spain) Percent	34	28	42

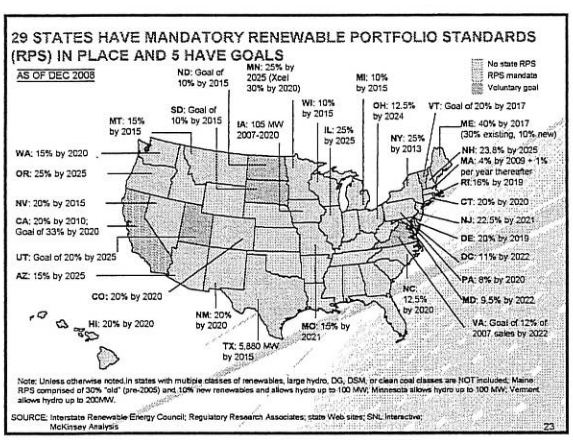
- Significant influence of Spain on 2008 global demand
- 2009 global solar demand dependent on
  - Continued legislative support in Germany, Italy and U.S.
  - New tariff introductions in Greece, India and Japan
  - Significant system cost reductions
  - Availability of high-leveraged project financing in key markets

Source: German PV Association; Spanish PV regulator; EPIA; Solarbuzz; Merrill Lynch; Bank Sarasin; PVNews; press search; McKinsey analysis

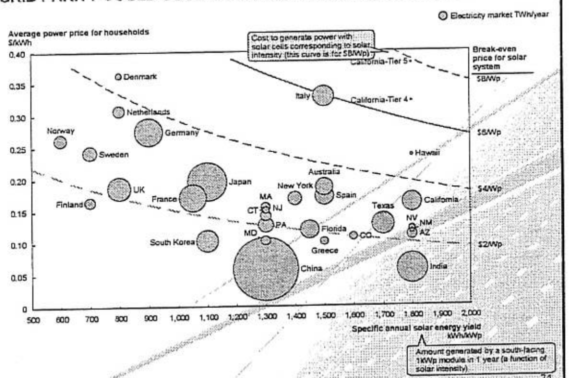
20


U.S. AND SOUTHERN EUROPE WILL BECOME KEY GROWTH MARKETS
Annual capacity additions
GW
100% = 1.5 5.6 13.8 19.8
Other countries
Southern Europe
U.S.
Japan
Germany
Rest of World
India
South Korea
Australia
China
Southern Europe
Rest of US
Southwest US
Northeast US
California US
Japan
Germany
2005 2010 2015 2020
Market share of Germany, Japan to decline from ~70% in 2005 to ~20% in 2020
U.S. and Southern Europe likely to gain ~45% market share in the next 5-10 years
Source: McKinsey proprietary demand model
21


MAJORITY OF EUROPEAN COUNTRIES HAVE IMPLEMENTED TARIFFS AS PRIMARY INCENTIVE MECHANISM*
None
Direct investment subsidies
Feed-in tariffs
Quotas/ RPS
Tax benefits
Number of countries by primary incentive mechanism
4
14
7
1
Direct investment subsidies
Direct tariffs
Quotas/ RPS
Tax benefits
* Primary incentive mechanism illustrated for countries with multiple incentive mechanisms
Source: EU PV Policy Group; government websites
22


29 STATES HAVE MANDATORY RENEWABLE PORTFOLIO STANDARDS (RPS) IN PLACE AND 5 HAVE GOALS
AS OF DEC 2008
No state RPS
RPS mandate
Voluntary goal
ND: Goal of 10% by 2015
MN: 25% by 2025 (Xcel 30% by 2020)
MI: 10% by 2015
SD: Goal of 10% by 2015
WI: 10% by 2015
OH: 12.5% by 2024
VT: Goal of 20% by 2017
MT: 15% by 2015
IA: 105 MW 2007-2020
IL: 25% by 2025
NY: 25% by 2013
ME: 40% by 2017 (30% existing, 10% new)
WA: 15% by 2020
NH: 23.8% by 2025
MA: 4% by 2009 + 1% per year thereafter
RI: 16% by 2019
OR: 25% by 2025
NV: 20% by 2015
CT: 20% by 2020
CA: 20% by 2010; Goal of 33% by 2020
NJ: 22.5% by 2021
DE: 20% by 2019
UT: Goal of 20% by 2025
DC: 11% by 2022
AZ: 15% by 2025
PA: 8% by 2020
CO: 20% by 2020
NC: 12.5% by 2020
MD: 9.5% by 2022
HI: 20% by 2020
NM: 20% by 2020
MO: 15% by 2021
VA: Goal of 12% of 2007 sales by 2022
TX: 5,880 MW by 2015
Note: Unless otherwise noted in states with multiple classes of renewables, large hydro, DG, DSM, or clean coal classes are NOT included; Maine RPS comprised of 30% "old" (pre-2005) and 10% new renewables and allows hydro up to 100 MW; Minnesota allows hydro up to 100 MW; Vermont allows hydro up to 200MW.
SOURCE: Interstate Renewable Energy Council; Regulatory Research Associates; state Web sites; SNL Interactive; McKinsey Analysis
23

GRID PARITY COULD SOON BE REACHED IN MANY COUNTRIES

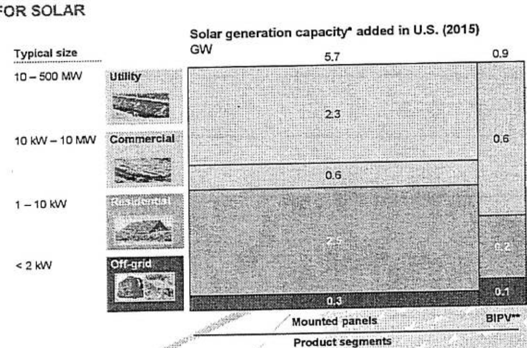


Source: Eurostat; PV Policy group; PG&E; CIA country files; Public policy Institute New York; EIA; team analysis

24

U.S. IS LIKELY TO SEE A SIGNIFICANT UTILITY MARKET FOR SOLAR

McKinsey 2008 model



* Includes PV measured in Wp and solar thermal measured in We

** BIPV = Building integrated photovoltaics

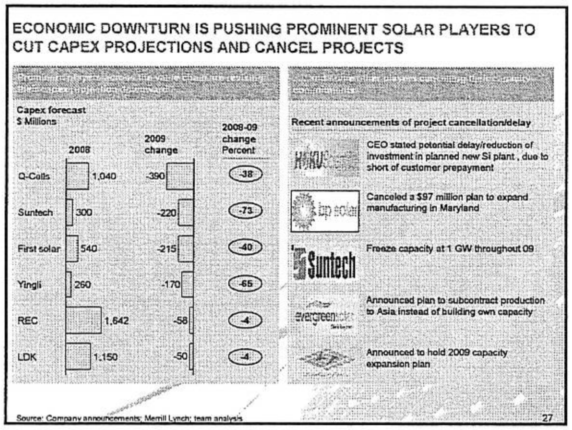
Source: McKinsey analysis; Yole report

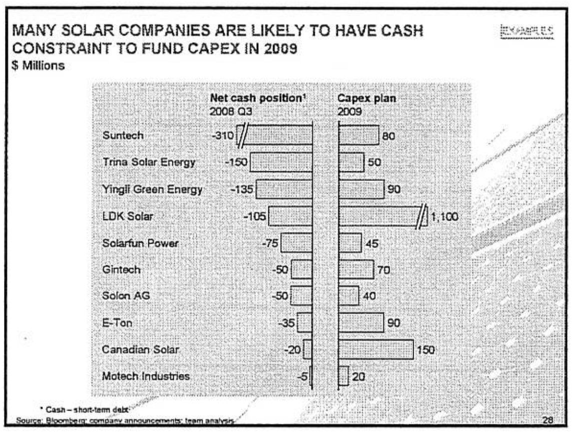
25

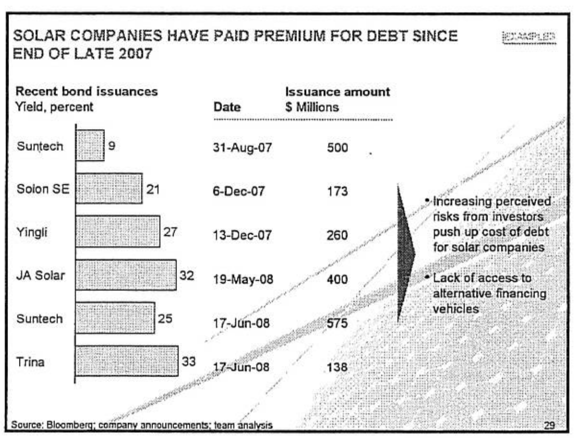
TODAY'S DISCUSSION

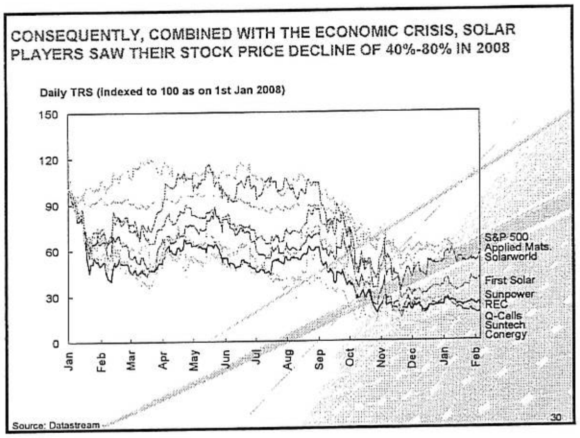
- Solar technologies and their evolution
- Demand growth outlook
- Perspectives on solar following the economic crisis

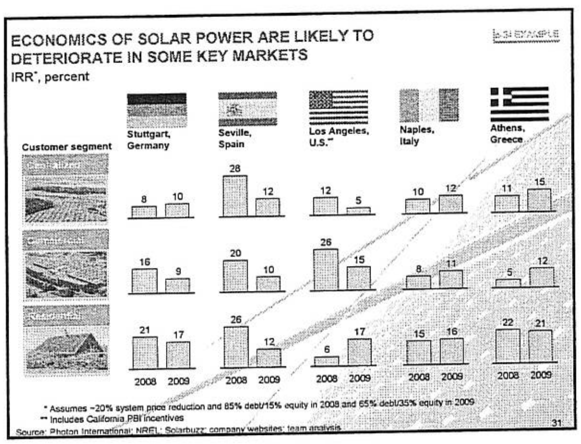
26

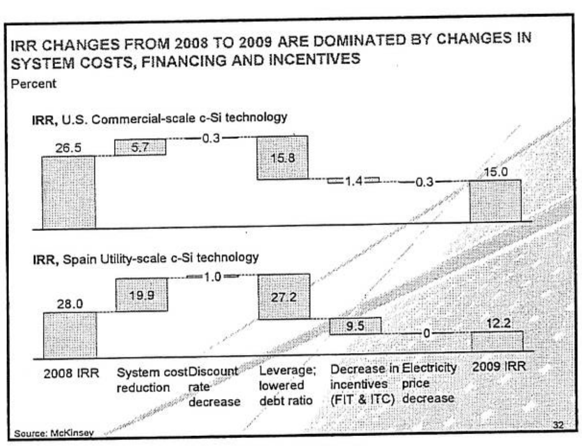

ECONOMIC DOWNTURN IS PUSHING PROMINENT SOLAR PLAYERS TO CUT CAPEX PROJECTIONS AND CANCEL PROJECTS
Capex forecast
$ Millions
2008
2009 change
2008-09 change Percent
Q-Cells 1,040 -390 -38
Suntech 300 -220 -73
First solar 540 -215 -40
Yingli 260 -170 -65
REC 1,642 -58 -4
LDK 1,150 -50 -4
Recent announcements of project cancellation/delay
CEO stated potential delay/reduction of investment in planned new Si plant, due to short of customer prepayment
Canceled a $97 million plan to expand manufacturing in Maryland
Suntech
Freeze capacity at 1 GW throughout 09
Announced plan to subcontract production to Asia instead of building own capacity
Announced to hold 2009 capacity expansion plan
Source: Company announcements; Merill Lynch; team analysis
27

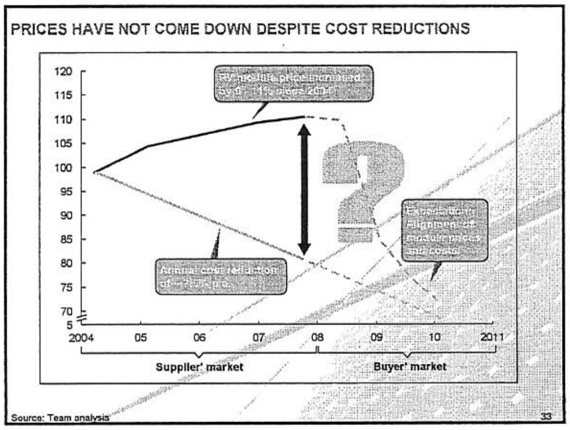

MANY SOLAR COMPANIES ARE LIKELY TO HAVE CASH CONSTRAINT TO FUND CAPEX IN 2009
$ Millions
Net cash position[1] 2008 Q3
Capex plan 2009
Suntech -310 80
Trina Solar Energy -150 50
Yingli Green Energy -135 90
LDK Solar -105 1,100
Solarfun Power -75 45
Gintech -50 70
Solon AG -50 40
E-Ton -35 90
Canadian Solar -20 150
Motech Industries -5 20
1 Cash – short-term debt
Source: Bloomberg; company announcements; team analysis
28

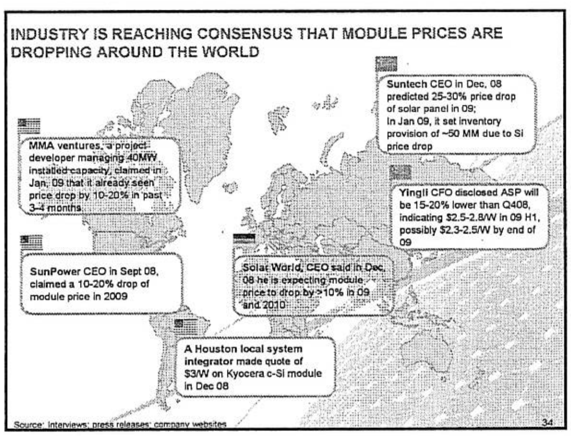

SOLAR COMPANIES HAVE PAID PREMIUM FOR DEBT SINCE END OF LATE 2007
Recent bond issuances
Yield, percent
Date
Issuance amount
$ Millions
Suntech 9 31-Aug-07 500
Solon SE 21 6-Dec-07 173
Yingli 27 13-Dec-07 260
JA Solar 32 19-May-08 400
Suntech 25 17-Jun-08 575
Trina 33 17-Jun-08 138
• Increasing perceived risks from investors push up cost of debt for solar companies
• Lack of access to alternative financing vehicles
Source: Bloomberg; company announcements; team analysis
29

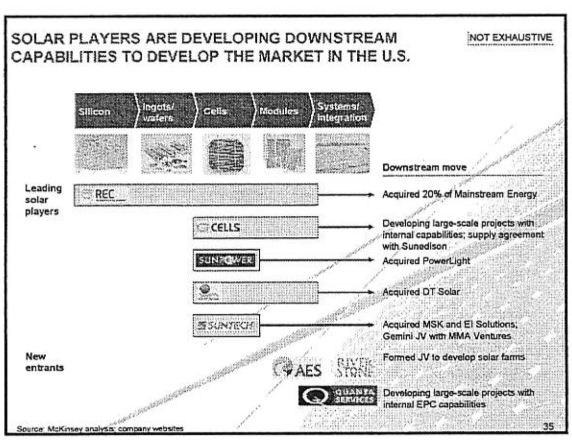

CONSEQUENTLY, COMBINED WITH THE ECONOMIC CRISIS, SOLAR PLAYERS SAW THEIR STOCK PRICE DECLINE OF 40%-80% IN 2008
Daily TRS (Indexed to 100 as on 1st Jan 2008)
150
120
90
60
30
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Jan
Feb
S&P 500
Applied Mats.
Solarworld
First Solar
Sunpower
REC
Q-Cells
Suntech
Conergy
Source: Datastream
30

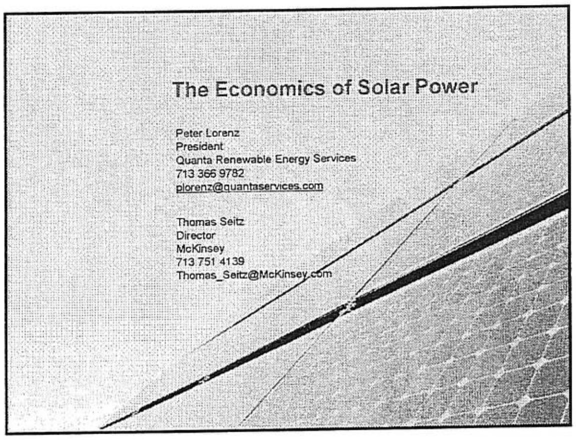

ECONOMICS OF SOLAR POWER ARE LIKELY TO DETERIORATE IN SOME KEY MARKETS
IRR*, percent
Customer segment
Stuttgart, Germany
Seville, Spain
Los Angeles, U.S.**
Naples, Italy
Athens, Greece
8 10
28 12
12 5
10 12
11 15
16 9
20 10
26 15
8 11
5 12
21 17
26 12
6 17
15 16
22 21
2008 2009
* Assumes ~20% system price reduction and 85% debt/15% equity in 2008 and 65% debt/35% equity in 2009
** Includes California PBI incentives
Source: Photon International; NREL; Solarbuzz; company websites; team analysis
31


IRR CHANGES FROM 2008 TO 2009 ARE DOMINATED BY CHANGES IN SYSTEM COSTS, FINANCING AND INCENTIVES
Percent
IRR, U.S. Commercial-scale c-Si technology
26.5
5.7
0.3
15.8
1.4
0.3
15.0
IRR, Spain Utility-scale c-Si technology
28.0
19.9
1.0
27.2
9.5
0
12.2
2008 IRR
System cost reduction
Discount rate decrease
Leverage; lowered debt ratio
Decrease in incentives (FIT & ITC)
Electricity price decrease
2009 IRR
Source: McKinsey
32


PRICES HAVE NOT COME DOWN DESPITE COST REDUCTIONS
120
115
110
105
100
95
90
85
80
75
70
5
2004
05
06
07
08
09
10
2011
Supplier' market
Buyer' market
Source: Team analysis
33


INDUSTRY IS REACHING CONSENSUS THAT MODULE PRICES ARE DROPPING AROUND THE WORLD
Suntech CEO in Dec, 08 predicted 25-30% price drop of solar panel in 09; In Jan 09, it set inventory provision of ~50 MM due to Si price drop
MMA ventures, a project developer managing 40MW installed capacity, claimed in Jan, 09 that it already seen price drop by 10-20% in past 3-4 months
Yingli CFO disclosed ASP will be 15-20% lower than Q408, indicating $2.5-2.8/W in 09 H1, possibly $2.3-2.5/W by end of 09
SunPower CEO in Sept 08, claimed a 10-20% drop of module price in 2009
Solar World, CEO said in Dec, 08 he is expecting module price to drop by >10% in 09 and 2010
A Houston local system integrator made quote of $3/W on Kyocera c-Si module in Dec 08
Source: Interviews; press releases; company websites
34


SOLAR PLAYERS ARE DEVELOPING DOWNSTREAM CAPABILITIES TO DEVELOP THE MARKET IN THE U.S.
NOT EXHAUSTIVE
Silicon
Ingots/ wafers
Cells
Modules
Systems/ integration
Downstream move
Leading solar players
REC
Acquired 20% of Mainstream Energy
CELLS
Developing large-scale projects with internal capabilities; supply agreement with Sunedison
SUNPOWER
Acquired PowerLight
Acquired DT Solar
SUNTECH
Acquired MSK and EI Solutions; Gemini JV with MMA Ventures
New entrants
AES
Formed JV to develop solar farms
QUANTA SERVICES
Developing large-scale projects with internal EPC capabilities
Source: McKinsey analysis; company websites
35


The Economics of Solar Power
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The McKinsey *Quarterly*

ENERGY, RESOURCES, MATERIALS

JUNE 2008

The economics of **solar power**

Don't be fooled by technological uncertainty and the continued importance of regulation; solar will become more economically attractive.

Peter Lorenz, Dickon Pinner, and Thomas Seitz

Article at a glance

Solar energy is becoming more economically attractive as technologies improve and the cost of electricity generated by fossil fuels rises.

By 2020, hundreds of billions of dollars of investment capital will probably boost global solar-generating capacity 20 to 40 times higher than its current level.

As the new sector takes shape, producers of solar components must drive their costs down, utilities must place big bets despite enormous technological uncertainty, and regulators must phase out subsidies with care.

The actions these players take will determine the solar sector's scale, structure, and performance for years to come.

HOUSE ENERGY AND UTILITIES
DATE: 3/3/2009
ATTACHMENT 3-1

A new era for solar power is approaching. Long derided as uneconomic, it is gaining ground as technologies improve and the cost of traditional energy sources rises. Within three to seven years, unsubsidized solar power could cost no more to end customers in many markets, such as California and Italy, than electricity generated by fossil fuels or by renewable alternatives to solar. By 2020, global installed solar capacity could be 20 to 40 times its level today.

But make no mistake, the sector is still in its infancy. Even if all of the forecast growth occurs, solar energy will represent only about 3 to 6 percent of installed electricity generation capacity, or 1.5 to 3 percent of output in 2020. While solar power can certainly help to satisfy the desire for more electricity and lower carbon emissions, it is just one piece of the puzzle.

What's more, solar power faces challenges that are common in emerging sectors. Several technologies are competing to win the lowest-cost laurels, and it's not yet clear which is going to win. Rapid growth has created shortages and high margins for early players, such as the silicon refiners Dow Corning, REC Solar, and Wacker, as well as the component manufacturers First Solar, Q-Cells, and SunPower. Fueled by ever-increasing flows of new equity from venture capital and private-equity firms—$3.2 billion in 2007—innovative new competitors are entering the sector, and with them the potential for excess supply, falling prices, and deteriorating financial performance for some time.

With competition heating up, the companies building the equipment that generates solar power must relentlessly cut their costs by improving the processes they use to manufacture solar cells, investing in research and development, and moving production to low-cost countries. At the same time, they must secure access to raw materials without tying themselves to the wrong technology or partner.

The evolution of technology looms large for utilities as well. If they hesitate to undertake large long-term investments until the dust clears, they risk losing customers to players such as panel installers willing to put up and finance solar units on the roofs of buildings in return for a share of the savings the owners enjoy. As always in the utility sector, it will be essential to deploy smart regulatory strategies, which in some regions might mean including solar investments in the capital base used to set rates for consumers. Government policies will also continue to influence the sector's development heavily. Deciding when and how to phase out subsidies will be critical for creating a vibrant, cost-competitive sector.

Even in the most favorable regions, solar power is still a few years away from true "grid parity"—the point when the price of solar electricity is on par with that of conventional sources of electricity on the power grid. The time frame is considerably longer in countries such as China and India, whose electricity needs will require large

3-2

amounts of new generating capacity in the years ahead and whose cheap power from coal makes grid parity a more elusive goal.

The birth of a sector

The solar sector includes a diverse set of players, including the manufacturers of the silicon wafers, panels, and components used to generate much of today's solar power, as well as the installers who put small-scale units on individual roofs, utilities and other operators setting up enormous solar collection systems in deserts, and start-up companies striving for breakthroughs such as lower-cost thin-film technologies. All are operating in a dynamic environment in which long-held assumptions—subsidies, the primacy of incumbents, and the predominance of silicon-wafer-based technology—are being eroded.

Beyond subsidies

Government subsidies have played a prominent role in the growth of solar power. Producers of renewable energy in the United States receive tax credits, for example, and Germany requires electricity distributors to pay above-market rates for electricity generated from renewable sources. Without such policies, the high cost of generating solar power would prevent it from competing with electricity from traditional fossil-fuel sources in most regions.

But the sector's economics are changing. Over the last two decades, the cost of manufacturing and installing a photovoltaic solar-power system has decreased by about 20 percent with every doubling of installed capacity. The cost of generating electricity from conventional sources, by contrast, has been rising along with the price of natural gas, which heavily influences electricity prices in regions that have large numbers of gas-fired power plants. These regions include California, the Northeast, and Texas (in the United States), as well as Italy, Japan, and Spain.

As a result, solar power has been creeping toward cost competitiveness in some areas. California, for example, combines abundant sunshine with retail electricity prices that, partly as a result of the state's policies, are among the highest in the United States—up to 36 cents per kilowatt-hour for residential users.[1] Unsubsidized solar power costs 36 cents per kilowatt-hour. Support from the California Solar Initiative [2] cuts the price customers pay to 27 cents. Rising natural-gas prices, state regulations aiming to limit greenhouse gas emissions, and the need to build more power plants to keep up with growing demand could push the cost of conventional electricity higher.

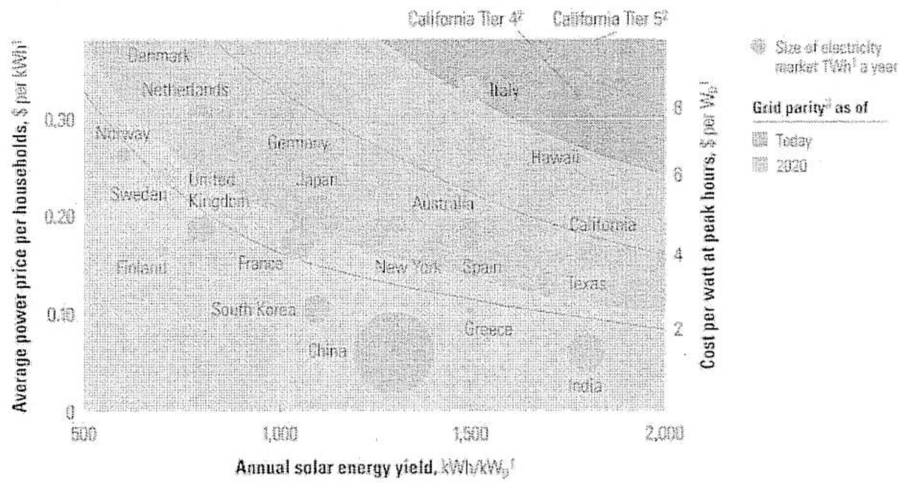
During the next three to seven years, solar energy's unsubsidized cost to end customers should equal the cost of conventional electricity in parts of the United States (California and the Southwest) and in Italy, Japan, and Spain. These markets have in common relatively strong solar radiation (or insolation), high electricity

3-3

prices, and supportive regulatory regimes that stimulate the solar-capacity growth needed to drive further cost reductions (Exhibit 1). These conditions set in motion a virtuous cycle: growing demand for solar power creates more opportunities for companies to reduce production costs by improving solar-cell designs and manufacturing processes, to introduce new solar technologies, and to enjoy lower prices from raw-material and component suppliers competing for market share.

EXHIBIT 1

The growing competitiveness of solar power



[1] kWh = kilowatt hour; kW_p = kilowatt peak; TWh = terawatt hour; W_p = watt peak; the annual solar yield is the amount of electricity generated by a south-facing 1 kW peak-rated module in 1 year, or the equivalent number of hours that the module operates at peak rating.
[2] Tier 4 and 5 are names of regulated forms of electricity generation and usage.
[3] Unsubsidized cost to end users of solar energy equals cost of conventional electricity.

Source: CIA country files; European Photovoltaic Policy Group; Eurostat; Pacific Gas & Electric (PG&E); Public Policy Institute of New York State; McKinsey Global Institute analysis

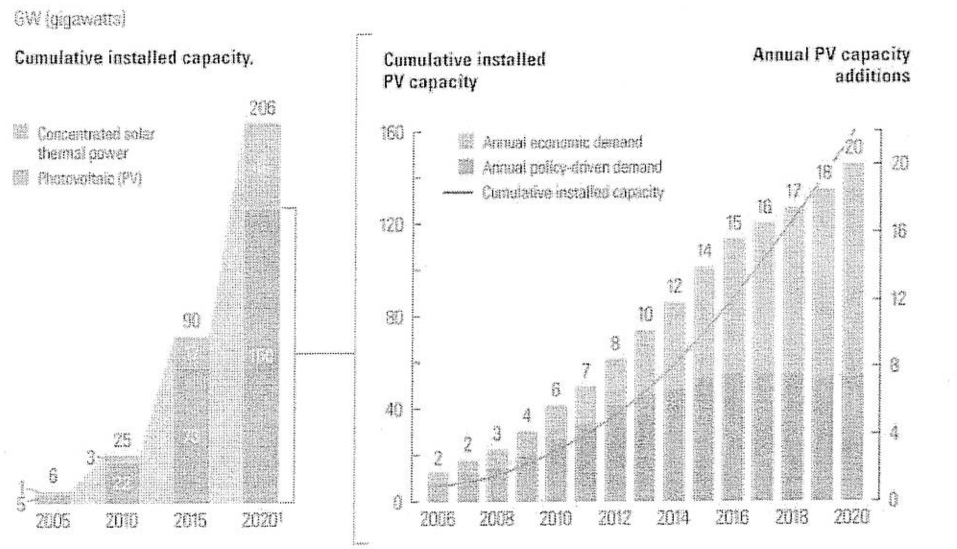
We forecast global solar demand by estimating the payback period for customers in different countries and regions. (Payback estimates rest on projected system costs and power prices, as well as local sunlight and incentive schemes.) Our analysis suggests that by 2020 at least ten regions with strong sunlight will have reached grid parity, with the price of solar electricity falling from upward of 30 cents per kilowatt-hour to 12, or even less than 10, cents. From now until 2020, installed global solar capacity will grow by roughly 30 to 35 percent a year, from 10 gigawatts today to about 200 to 400 gigawatts[3] (Exhibit 2), requiring capital investments of more than $500 billion. Even though this volume represents only 1.5 to 3 percent of global electricity output, the roughly 20 to 40 new gigawatts a year of installed solar capacity would provide about 10 to 20 percent of annual new power capacity over that period.

3-4

This level of installed solar capacity would abate some 125 to 250 megatons of carbon dioxide—roughly 0.3 to 0.6 percent of global emissions in 2020.

EXHIBIT 2

The global solar market in 2020



[1]Estimate uses base-case scenario. Aggressive scenario predicts 400 GW in 2020.

Evolving technologies

Our demand and capacity forecasts assume continued improvement in solar-cell designs and materials but neither a radical breakthrough nor the emergence of a dominant technology. At present, three technologies—silicon-wafer-based and thin-film photovoltaics and concentrated solar thermal power—are competing for cost leadership. Each has its advantages for certain applications, but none holds the overall crown. Major innovations and shifts in the relative cost competitiveness of these technologies could occur.

Companies that use either of the current photovoltaic technologies, which generate electricity directly from light, are striving to reduce costs by making their systems more efficient. In power conversion, efficiency means the amount of electrical power generated by the solar radiation striking the surface of a photovoltaic cell in a given period of time. For each unit of power generated, more efficient systems require less raw material and a smaller solar-collection surface area, weigh less, and are cheaper to transport and install.

3-5

Silicon-wafer-based photovoltaics. Although 90 percent of installed solar capacity uses silicon-wafer-based photovoltaic technology, it faces two challenges that could create openings for competing approaches. For one thing, though it is well suited to space-constrained rooftop applications (because it is roughly twice as efficient as current thin-film photovoltaic technologies), the solar panels and their installation are costly: larger quantities of photovoltaic material (in this case, silicon) are required to make the panels than are to make thin-film photovoltaic solar cells.[4] Second, companies are starting to approach the theoretical efficiency limit—31 percent—of a single-junction silicon-wafer-based photovoltaic cell; several now achieve efficiencies in the 20 to 23 percent range. To be sure, there is still room for improvement before the limit is reached, and clever engineering techniques (such as concentrating sunlight on solar cells or adding a number of junctions made of different materials to absorb a larger part of the light spectrum more efficiently) could extend it, though many of these ideas increase production costs.

Thin-film photovoltaics. The other important photovoltaic approach, thin-film technology,[5] has been available for many years but only recently proved that it can reach sufficiently high efficiency levels (about 10 percent) at commercial production volumes. Thin film trades off lower efficiencies against a significantly lower use of materials—about 1 to 5 percent of the amount needed for silicon-wafer-based photovoltaics. The result is a cost structure roughly half that of wafer-based silicon. This technology also has significant headroom to extend the cost gap in the long term.

But challenges abound. The lower efficiency of thin-film modules[6] means that they are currently best suited to large field installations and to large, flat rooftops. Furthermore, the longevity of these modules is uncertain; silicon-wafer-based photovoltaics, by contrast, maintain their output at high levels for more than 25 years. Of the most promising thin-film technologies, only one—cadmium telluride—has truly reached commercial scale, and some experts worry about the toxicity of cadmium and the availability of tellurium. A final complicating factor is that a new generation of nanoscale thin-film technologies now on the horizon could significantly increase the efficiency and reduce the cost of producing solar power.

Concentrated solar thermal power. The third major solar technology, concentrated solar thermal power,[7] is the cheapest available option today but has two limitations. Photovoltaic systems can be installed close to customers, thereby reducing the expense of transmitting and distributing electricity. But concentrated solar thermal power systems require almost perfect solar conditions and vast quantities of open space, both often available only at a great distance from customers. In addition, the ability of concentrated solar thermal power to cut costs further may be limited, because it relies mostly on conventional devices such as pipes and reflectors, whose costs will probably fall less significantly than those of the materials used in

3-6

semiconductor-based photovoltaics. Nonetheless, several European utilities now regard concentrated solar thermal power as the solar technology of choice.

The road ahead

The extent and speed of this diverse and complex emerging sector's growth will depend on its ability to keep driving down the cost of solar power. No single player or set of players can make that happen on its own.

- The necessary technological breakthroughs will come from solar-component manufacturers, but rapid progress depends on robustly growing demand from end users, to whom many manufacturers have only limited access.

- Utilities have strong relationships with residential, commercial, and industrial customers and understand the economics of serving them. But these companies will have difficulty driving the penetration of solar power unless they have a much clearer sense of the cost potential of different solar technologies.

- In some regions, regulators can accelerate the move toward grid parity, as they did in California and Germany, but they can't reduce the real cost of solar power. Poor regulation might even slow the fall in prices.

Although these considerations make it difficult to predict outcomes and to prescribe strategies, certain economic principles do apply.

Solar-component manufacturers

The fundamentals are clear for photovoltaic-component manufacturers that hope to remain competitive: there's no escaping significant R&D investments to stimulate continued efficiency improvements, as well as operational excellence to drive down manufacturing costs. Furthermore, in view of the technological uncertainty, established silicon-wafer-based companies should hedge their bets by investing in advanced thin-film technologies.

Some manufacturers have considered establishing partnerships or vertically integrating—approaches that could give them access to supplies, customers, and financing but might also lock them into the wrong technology. To make the right trade-offs, the manufacturers of components for silicon-wafer-based and thin-film technologies should focus on fundamentals, such as manufacturing costs, efficiency improvements, and the movement of prices for raw materials.

Raw materials. Polysilicon is the main raw material for silicon-wafer-based solar-cell manufacturers, which now consume more of it than the semiconductor industry does. Over the last two years, shortages and price spikes have been the result.

3-7

Cell manufacturers shouldn't overreact to this tight environment by making big bets on supply and demand contracts for polysilicon or by forging onerous partnerships with suppliers. High margins have encouraged incumbents to add capacity and have attracted new entrants. Many observers have therefore been predicting that global polysilicon production capacity will at least triple from 2005 to 2010, and our forecasts indicate that demand for the material will only double during the same period. This mismatch suggests that the spot price of polysilicon wafers could drop from over $200 a ton to the variable cost of production—as little as $25 to $50.

Production process technology. The way companies manufacture solar cells has the largest impact on the cells' efficiency and their cost. Many incumbents have invested heavily in developing proprietary manufacturing processes. Some start-up cell manufacturers, by contrast, buy entire manufacturing lines from equipment companies such as Applied Materials.

Cell manufacturers are valuable partners for equipment companies hoping to tap into the growth of the solar sector. The equipment companies need formal partnerships that will allow them to retain ownership of the intellectual property associated with their manufacturing processes—a difficult trick that these vendors tried (and failed) to pull off in the semiconductor sector. The same thing could happen again unless equipment providers can figure out how to make their offerings extremely cost competitive and difficult for operators to imitate or enhance.

Producing in low-cost regions. Many leading silicon-wafer-based photovoltaic solar companies are located in high-wage countries. These manufacturers produce cells that are typically more efficient than those produced in lower-wage countries; for example, many German and US cells achieve an efficiency of 20 percent or more, compared with 15 to 16 percent for Chinese ones. Yet countries like China and India will inevitably gain an overall cost advantage by developing the skills needed to produce more efficient cells. Companies in regions with high labor costs should therefore constantly monitor the benefits and risks of locating their next plant in an area that offers lower-cost labor and generous subsidies.

Utilities

Although the distributed nature of solar power might seem to clash with the utilities' business model of centralized electricity generation, these companies do have assets in the solar era, starting with strong customer relationships. They are also in a good position to integrate electricity generated at large numbers of different locations (such as rooftops) into the existing network. Many utilities could use their advanced metering infrastructure to calculate the full value of solar power during peak times.

One way of leveraging these assets would be to form partnerships with component manufacturers. Building profitable partnerships will require utilities to develop new

3-8

skills, such as installing and managing solar-generation capacity, as well as deciding which solar technologies best suit their service territories.

The technology that currently seems most attractive for utilities is concentrated solar thermal power, because it involves centralized electricity generation—much as traditional coal, nuclear, and hydroelectric facilities do—and is today's low-cost solar champion. Its long-term cost prospects, though, are less favorable than those of some emerging photovoltaic technologies, so choosing it now is in effect a strategic bet on how quickly relative costs and local subsidy environments will change.

While the natural tendency might be to postpone investments until the technology picture becomes clearer, sitting on the sidelines could hurt the utilities. As the cost of solar energy decreases, the growing number of companies that will probably enter the business of installing solar equipment could cut off some utilities from their customers. Installers buy solar panels, mount them in homes and businesses, and then lease them in return for a stream of payments lower than prevailing electricity rates but still high enough to earn a healthy return on the panel investment. Since people who now pay the highest electricity rates would be the most likely to switch, utilities would lose their most valuable customers.

One way of coping would be to forge relationships with solar-cell and -module manufacturers that could help utilities claim a portion of this emerging business while they gain experience integrating distributed generating capacity into the grid. It should be in their interest to strike up such partnerships quickly, before disintermediation reduces their attractiveness as partners, since savvy manufacturers will pit them against installers in a quest for the most favorable financial arrangements.

Another approach for the utilities involves a regulatory strategy—for example, they could try to persuade regulators to add solar investments to their rate base (the expenses and capital investments that regulators use to calculate fair retail electricity prices). Although such a readjustment would raise electricity rates, utilities could argue that the long-term benefits would be significant: increasing their reserve margins while making conventional power generation investments unnecessary, dampening future rate increases from rising fuel prices, meeting environmental targets, and accelerating the decline in solar-power costs. This approach yields a fixed return on capital that might ultimately be lower than what would be possible if utilities bet successfully on the right technologies, but it also mitigates investment risk.

Governments and regulators

The decisions of regulators will affect not only utilities but also the entire solar sector. During the march to grid parity, well-understood and targeted subsidies will be critical to build the confidence of investors and attract capital. The impact of government policies in rapidly growing emerging markets such as China and India will be particularly important for the pace of the sector's growth. Our base-case forecasts do not include aggressive growth in these markets. But if China installed rooftop solar panels on, say, 13 percent of all new construction in 2020, the country would add 15 gigawatts of solar capacity a year, about 40 percent of the world's annual increase. Similarly, government policies encouraging the use of electric vehicles may also accelerate the growth of solar demand.

While the optimal regulations for different countries will vary considerably, all governments should focus on a few major factors.

- *Clarify objectives.* Before establishing policies, regulators must decide whether they want to increase energy security, lower carbon emissions, build a high-tech manufacturing cluster, create jobs for installers, or any combination of these goals. Once regulators have identified and prioritized them, appropriate policies can be developed to stimulate specific parts of the sector.

- *Reward production, not capacity.* Subsidizing capacity rewards all solar-power installations at the same rate, regardless of their cost-efficiency. Production-based programs, which reward companies only for generating electricity, create incentives to reduce costs and to focus initially on attractive areas with high levels of sunlight.

- *Phase out subsidies carefully.* In virtually every region of the world, solar subsidies are still crucial; in 2005, when they expired in Japan, capacity growth declined there significantly. But since solar power could eventually be cost competitive with conventional sources, regulators must adjust incentive structures over time and phase them out when grid parity is reached.

Solar energy is becoming more economically attractive. Component manufacturers, utilities, and regulators are making decisions now that will determine the scale, structure, and performance of this new sector. Technological uncertainty makes the choices difficult, but the opportunities—for companies to profit and for the world to become less dependent on fossil fuels—are significant.

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3-10

Notes

[1] Residential retail electricity prices in California increase with the end customer's usage.

[2] The California Solar Initiative provides $3.1 billion of subsidies to install 3 gigawatts, or 3 billion watts, of capacity by 2017.

[3] One gigawatt = one billion watts. As a point of reference, the capacity of a typical coal plant is about 0.6 to 1.0 gigawatts.

[4] Silicon absorbs light less well than the materials currently used to make thin-film photovoltaic solar cells, so they must be thicker to absorb the same amount of light.

[5] Leaving aside nanoscale materials and technologies, there are currently four promising thin-film technologies: cadmium telluride, copper indium gallium diselenide, amorphous silicon, and thin-film polysilicon.

[6] A module is a collection of cells that have been connected together to generate higher current and voltages.

[7] Photovoltaic systems use semiconductor materials to convert light directly into electricity. Concentrated solar thermal power uses mirrors to reflect sunlight onto fluids, which heat up and then pass through a heat exchanger to generate steam and drive a turbine. Such technologies include parabolic troughs, power towers, linear Fresnel reflectors, dish Stirling systems, and solar chimneys.

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3-11

Tracking the Sun

The Installed Cost of Photovoltaics in the U.S. from 1998-2007

Ryan Wiser
Galen Barbose
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February 2009

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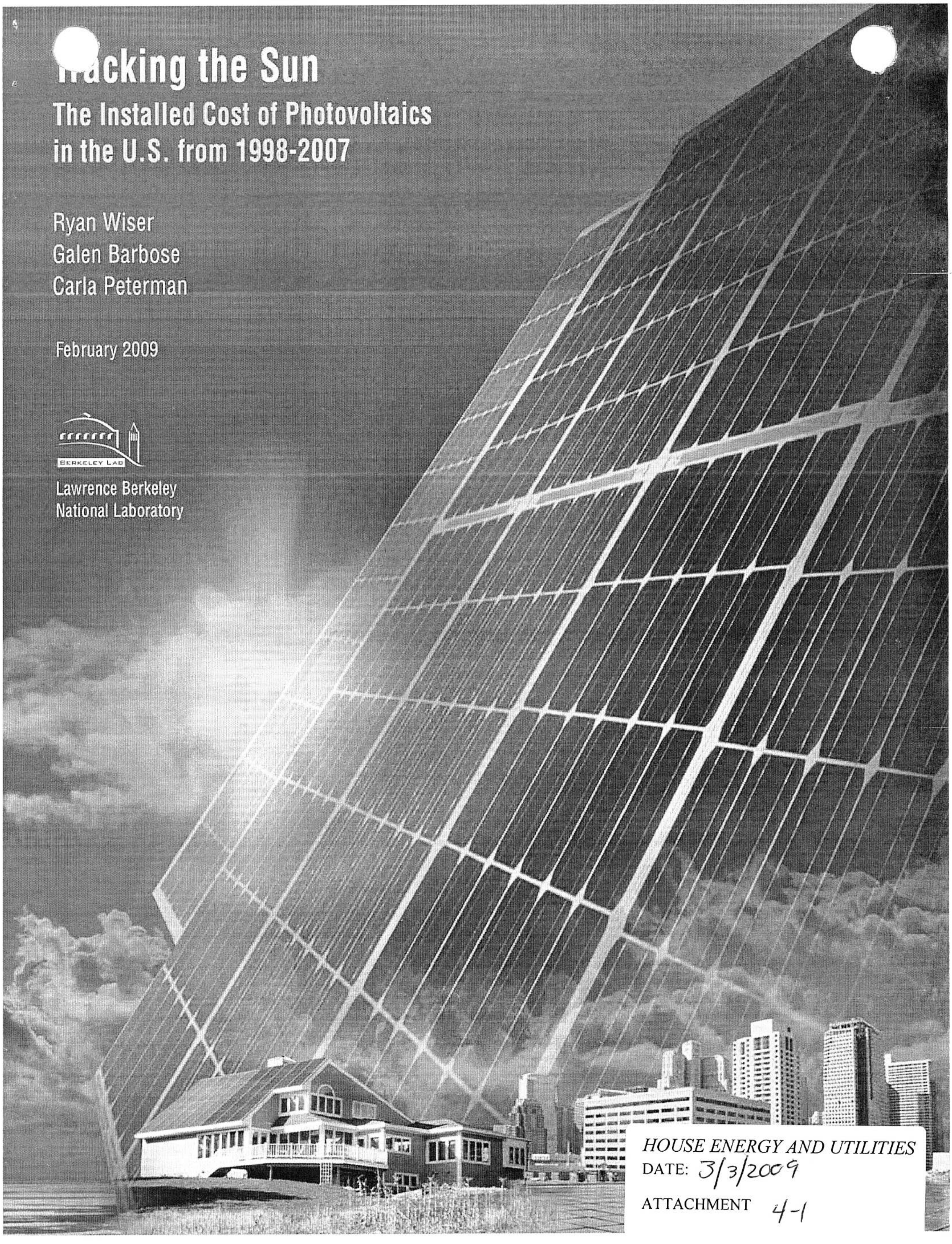

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Tracking the Sun

The Installed Cost of Photovoltaics in the U.S. from 1998-2007

Primary Authors: Ryan Wiser, Galen Barbose, and Carla Peterman

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Contents

Executive Summary 1

1. Introduction 3

2. Data Summary 5

3. PV Installed Cost Trends 9

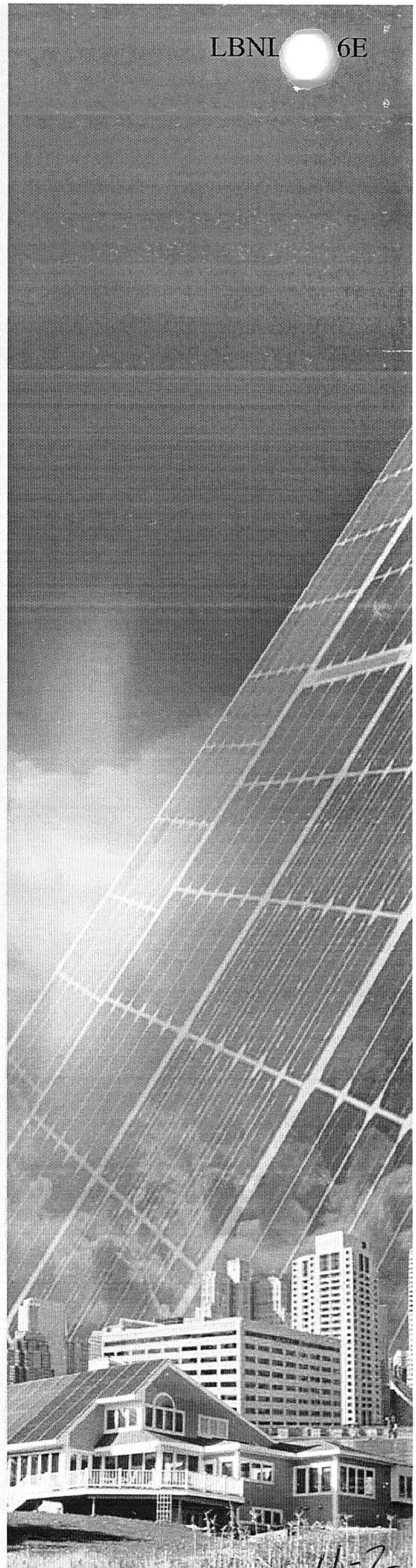
   - Installed Costs Have Declined over Time, but Were Stable from 2005-2007 9
   - Installed Cost Reductions Are Primarily Associated with Non-Module Costs 10
   - Historical Cost Reductions Are Most Evident for Systems Smaller than 100 kW 11
   - The Distribution of Installed Costs Has Narrowed over Time 11
   - Installed Costs Exhibit Significant Economies of Scale 12
   - Average Installed Costs Are Lower in Germany and Japan than in the U.S 14
   - Installed Costs Vary Widely Across States 15
   - The New Construction Market Offers Cost Advantages for Residential PV 16
   - Systems with Thin-Film Modules Had Higher Installed Costs in 2006 and 2007 than Those with Crystalline Modules 18
   - Module Costs Represent About Half of Total PV Installed Costs, with the Remainder Consisting of a Diversity of Non-Module Cost Components 19

4. PV Incentive and Net Installed Cost Trends 21

   - State/Utility Cash Incentives Have Declined since 2002 21
   - Including Federal and State ITCs, Financial Incentives Rose for Commercial PV from 2002-2007, But Fell for Residential PV 23
   - Declining Financial Incentives for Residential PV Offset Much of the Cost Reductions from 2001-2007, While Net Installed Costs for Commercial PV Continued to Fall 25
   - Incentives Have Diverged Widely Across States 26

5. Conclusions 29

Appendix 30



Executive Summary

As installations of grid-connected solar photovoltaic (PV) systems have grown, so too has the desire to track the installed cost of these systems over time, by system characteristics, by system location, and by component. This report helps to fill this need by summarizing trends in the installed cost of grid-connected PV systems in the United States from 1998 through 2007.[1] The report is based on an analysis of installed cost data from nearly 37,000 residential and non-residential PV systems, totaling 363 MW of capacity, and representing 76% of all grid-connected PV capacity installed in the U.S. through 2007.

Key findings of the analysis are as follows:[2]

- Among all PV systems in the dataset, average installed costs – in terms of real 2007 dollars per installed watt (DC-STC) and prior to receipt of any direct financial incentives or tax credits – declined from $10.5/W in 1998 to $7.6/W in 2007. This equates to an average annual reduction of $0.3/W, or 3.5%/yr in real dollars.
- The overall decline in installed costs over time is primarily attributable to a reduction in non-module costs, calculated as the total installed cost of each system minus a global annual average module price index. From 1998-2007, average non-module costs fell from $5.7/W to $3.6/W, representing 73% of the average decline in total installed costs over this period. This suggests that state and local PV deployment programs – which likely have a greater impact on non-module costs than on module prices – have been at least somewhat successful in spurring cost reductions.
- Average installed costs have declined since 1998 for systems <100 kW, with systems <5 kW exhibiting the largest absolute reduction, from $11.8/W in 1998 to $8.3/W in 2007. Cost reductions for systems >100 kW are less apparent, although the paucity of data for earlier years in the study period may limit the significance of this finding.
- The distribution of installed costs within a given system size range has narrowed significantly since 1998, with high-cost outliers becoming increasingly infrequent, indicative of a maturing market.
- Both the decline in average costs and the narrowing of cost distributions halted in 2005, with average costs and cost distributions remaining essentially unchanged from 2005-2007.
- PV installed costs exhibit significant economies of scale, with systems <2 kW completed in 2006 or 2007 averaging $9.0/W and systems >750 kW averaging $6.8/W (i.e., about 25% less than the smallest systems).
- Average installed costs vary widely across states; among systems <10 kW completed in 2006 or 2007, average costs range from a low of $7.6/W in Arizona (followed by California and New Jersey, which had average installed costs of $8.1/W and $8.4/W, respectively) to a high of $10.6/W in Maryland.
- International experience suggests that greater near-term cost reductions may be possible in the U.S. The average cost of residential PV installations in 2007 (excluding sales/value-added tax) in both Japan ($5.9/W) and Germany ($6.6/W) was significantly below that in

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[1] Although the report is intended to portray national trends, with 12 states represented within the dataset, the overall sample is heavily skewed towards systems in California and New Jersey, where the vast majority of PV systems in the U.S. have been installed.

[2] Unless otherwise noted, the results reflect all system types (e.g., rack-mounted, building-integrated, tracking, non-tracking, crystalline, non-crystalline, etc.).

4-3

the United States ($7.9/W). Variations in average installed cost across states, as well as comparisons with Japan and Germany, suggest that markets with large PV deployment programs often tend to have lower average installed costs for residential PV.

- The new construction market offers cost advantages for residential PV; among 1-3 kW systems funded by California's Emerging Renewable Program and completed in 2006 or 2007, PV systems installed in residential new construction cost $0.6/W less than comparably-sized residential retrofit systems (or $0.8/W less if focused exclusively on rack-mounted systems).
- Somewhat surprisingly, among systems <10 kW and installed in 2006 or 2007, those with thin-film modules were found to cost $0.5/W more, on average, than those employing crystalline modules. Among larger systems completed in 2006 or 2007, average installed costs did not differ substantially between crystalline and thin-film systems.
- The limited component-level cost data that are available (for systems <100 kW only) indicate that, on average, module costs represent just over 50% of total installed costs, while inverter costs represent just under 10%. Smaller residential systems are faced with higher overhead, regulatory compliance, and other costs (on a $/W basis) than are larger systems.
- State and utility cash incentives for PV declined significantly, on average, from 2002 through 2007 across all system size categories. Among systems <5 kW, for example, pre-tax incentives declined from 2002-2007 by an average of $1.9/W (from $4.3/W to $2.4/W).
- As a result of the increase in the Federal investment tax credit (ITC) for commercial systems in 2006, however, total after-tax incentives for commercial PV (i.e., state/utility cash incentives plus state and Federal ITCs, but excluding revenue from renewable energy certificate sales and the value of accelerated depreciation) were $3.9/W in 2007, an all-time high. Total after-tax incentives for residential systems, on the other hand, averaged $3.1/W in 2007, their lowest level since 2001. These trends may partially explain the shift towards the commercial sector within the U.S. PV market over this period. Starting in 2009, however, residential PV is likely to receive some gain in overall incentive levels with the lifting of the dollar cap on the Federal residential ITC.
- Due to the overall decline in total after-tax incentives for residential PV from 2001-2007, the net installed cost of residential PV (installed cost minus state/utility cash incentives and tax credits) averaged $5.1/W in 2007, just 7% below 2001 levels. The net installed cost of commercial PV, however, averaged $3.9/W in 2007, a near-record low and 32% below average net installed costs in 2001.
- Financial incentives and net installed costs diverge widely across states. Among residential PV systems completed in 2007, the combined after-tax incentive ranged from $2.5/W in Maryland to $5.7/W in Pennsylvania. These two states also represent the bookends in terms of net installed costs for residential PV, which averaged $3.2/W in Pennsylvania and $7.7/W in Maryland. Incentives and net installed costs for commercial systems varied similarly across states.
- Although average installed costs remained flat from 2005-2007, recent developments portend a potentially dramatic shift over the next few years in the customer-economics of PV. Most industry experts anticipate an over-supply of PV modules in 2009, putting downward pressure on module prices, and presumably on total installed costs as well. In addition, the lifting of the cap on the Federal ITC for residential PV, also beginning in 2009, will further reduce net installed costs for residential installations, potentially leading to some degree of renewed emphasis on the residential market in the years ahead.

1. Introduction

Installations of solar photovoltaic (PV) systems have been growing at a rapid pace in recent years. In 2007, 3,400 MW of PV was installed globally, up from 2,200 MW in 2006 and dominated by grid-connected applications. Cumulatively, roughly 10,600 MW of PV was installed worldwide by the end of 2007.[3] The United States was the world's fourth largest PV market in terms of annual capacity additions in 2007, behind Germany, Spain, and Japan; 205 MW of PV was added in the U.S. in 2007, 152 MW of which came in the form of grid-connected installations.[4] Despite the significant year-on-year growth, however, the share of global and U.S. electricity supply met with PV remains small, and annual PV additions are currently modest in the context of the overall electric system.

The market for PV in the U.S. is driven by national, state, and local government incentives, including up-front cash rebates, production-based incentives, requirements that electricity suppliers purchase a certain amount of solar energy, and Federal and state tax benefits. These programs are, in part, motivated by the popular appeal of solar energy, and by the positive attributes of PV – modest environmental impacts, avoidance of fuel price risks, coincidence with peak electrical demand, and the location of PV at the point of use. Given the relatively high cost of PV, however, a key goal of these policies is to encourage cost reductions over time. Therefore, as policy incentives have become more significant and as PV deployment has accelerated, so too has the desire to track the installed cost of PV systems over time, by system characteristics, by system location, and by component.

This report seeks to fill this need by summarizing major trends in the installed cost (i.e., the cost paid by the system owner, prior to the receipt of any available incentives) of grid-connected PV systems in the U.S. from 1998 through 2007.[5] The report is based on an analysis of project-level cost data from nearly 37,000 residential and commercial PV systems in the U.S., all of which are installed on the utility-customer side of the meter (i.e., "customer-sited" systems). These systems total 363 MW, or 76% of all grid-connected PV capacity installed in the U.S. by the end of 2007, representing the most comprehensive source of installed PV cost data in the United States. In addition to the primary dataset, which is limited to data provided directly by PV incentive program administrators and only includes systems installed on the utility-customer side of the meter, the report also summarizes installed cost data obtained through public data sources for five multi-MW grid-connected PV systems in the U.S. (several of which are installed on the utility-side of the meter). These additional large systems represent a combined 32 MW, bringing the total dataset to 395 MW, or 89% of all grid-connected PV capacity installed in the U.S. through 2007. The report also briefly compares recent PV installed costs in the U.S. to those in Germany and Japan. Finally, it should be noted that the analysis presented here focuses on descriptive trends in the underlying

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[3] Photon Consulting. 2008. *Solar Annual 2008: Four Peaks*. Boston, Massachusetts. Installed capacity totals refer to power applications, and exclude wafer-integrated products (e.g., electronic devices).

[4] Sherwood, L. 2008. *U.S. Solar Market Trends 2007*. Interstate Renewable Energy Council. http://www.irecusa.org. Note that there is some uncertainty over the correct number for 2007 grid-connected capacity additions in the U.S.

[5] This report focuses on installed costs paid by the system owner, rather than the costs born by manufacturers or installers. It is possible, especially over the past several years, that cost trends may have diverged between manufacturers and installers, or between installers and system owners. Note also that, in focusing on installed costs, the report ignores improvements in the performance of PV systems, which will tend to reduce the levelized cost of energy of PV even absent changes in installed costs.

4-5

data, and is primarily summarized in tabular and graphical form; later analysis may explore some of these trends with more-sophisticated statistical techniques.

The report begins with a summary of the data collection methodology and resultant dataset (Section 2). The primary findings of the analysis are presented in Section 3, which describes trends in installed costs over time, by system size, by state, by application (new construction vs. retrofit), and by technology type (building-integrated vs. rack-mounted and crystalline silicon vs. thin-film). Section 3 also describes trends related to non-module costs and component-level costs, drawing on a limited amount of available component-level cost data and the results of a 2008 survey of PV system installers conducted by Berkeley Lab. Section 4 presents additional findings related to trends in PV incentive levels over time and among states (focusing specifically on state and utility incentive programs as well as state and Federal tax credits), and trends in the net installed cost paid by system owners after receipt of such incentives. Brief conclusions are offered in the final section.

4-6

2. Data Summary

This section briefly describes the procedures used to collect, standardize, and clean the data provided by individual PV incentive programs, and summarizes the basic characteristics of the resulting dataset, including: the number of systems and installed capacity by PV incentive program and by year, the sample distribution by state and project size, and the sample size relative to all grid-connected PV capacity installed in the U.S.

Data Collection, Conventions, and Data Cleaning

Requests for project-level installed cost data were sent to state and utility PV incentive program administrators from around the country, with some focus (though not exclusively so) on relatively large programs. Ultimately, 16 PV incentive programs provided project-level installed cost data. To the extent possible, this report presents the data as provided directly by these PV incentive program administrators. That said, several steps were taken to standardize and clean the data, which are briefly summarized here and described in greater detail in Appendix A.

In particular, two key conventions used throughout this report deserve specific mention:

1. All cost and incentive data are presented in real 2007 dollars (2007$), which required inflation adjustments to the nominal-dollar data provided by PV programs.
2. All capacity and dollars-per-watt ($/W) data are presented in terms of rated module power output under Standard Test Conditions (DC-STC), which required that capacity data provided by several programs that use a different capacity rating be translated to DC-STC.

Additionally, the data were cleaned by eliminating projects with clearly erroneous cost or incentive data, by correcting text fields with obvious errors, and by standardizing the identifiers for module and inverter models. Finally, each PV system in the dataset was classified as either building-integrated PV or rack-mounted, and as using either crystalline or thin-film modules, based on a combination of information sources.

Sample Description

The final dataset, after all data cleaning was completed, consists of roughly 37,000 grid-connected, residential and non-residential PV systems, totaling 363 MW (see Table 1).[6] In aggregate, the PV systems in the dataset represent a significant fraction of the U.S. grid-connected PV market, equivalent to approximately 76% of all grid-connected PV capacity installed in the U.S. through 2007, and about 70% of the PV capacity installed in 2007 alone (see Figure 1).[7] The largest state markets missing from the primary data sample, in terms of cumulative installed PV capacity through 2007, are: Nevada (representing 4.0% of total U.S. grid-connected PV capacity), Colorado (3.1%), Hawaii (0.9%), and Texas (0.7%).[8]

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[6] There may be a moderate level of double-counting of systems between programs, particularly between LADWP's Solar Incentive Program and the ERP and SGIP programs in California, and between the two Illinois programs.
[7] Sherwood, L. 2008. *U.S. Solar Market Trends 2007*. Interstate Renewable Energy Council. http://www.irecusa.org.
[8] Some data on larger PV installations in both Colorado and Nevada are included in this report outside of the primary dataset, as summarized in the next paragraph. Additional data from Nevada were provided to Berkeley Lab, but are not included in this report; those data will be included in subsequent updates.

The primary sample consists only of data provided by PV incentive program administrators, all of which are for systems installed on the utility-customer side of the meter. The report separately describes the installed cost of five multi-MW grid-connected PV systems, several of which are installed on the utility-side of the meter.[9] Cost data for these projects were compiled from press releases and other publicly available sources. The data for these five projects bring the total PV capacity for which cost data are presented to 395 MW, equal to 89% of all grid-connected PV capacity in the U.S. installed through 2007.

Table 1. Data Summary by PV Incentive Program

State	PV Incentive Program	No. of Systems	Total MW	% of Total MW	Size Range (kW)	Year Range
AZ	Solar Partners Incentive Program (Arizona Public Service)	540	3.1	0.9%	0.4 – 255	2002 - 2007
CA	Emerging Renewables Program (California Energy Commission)	27,267	143.0	39.4%	0.1 – 670	1998 - 2007
CA	Self Generation Incentive Program (Pacific Gas & Electric, Southern California Edison, California Center for Sustainable Energy)	801	132.6	36.5%	34 – 1,265	2002 - 2007
CA	California Solar Initiative (Pacific Gas & Electric, Southern California Edison, California Center for Sustainable Energy)	2,303	14.3	3.9%	1.2 – 1,182	2007
CA	Solar Incentive Program (Los Angeles Dept. of Water & Power)	592	10.6	2.9%	0.3 – 467	1999 - 2006
CT	Solar PV and Onsite Renewable DG Programs (Connecticut Clean Energy Fund)	311	2.7	0.7%	1.0 – 434	2003 - 2007
IL	Renewable Energy Grant Programs (Illinois Clean Energy Community Foundation)	21	0.6	0.2%	1.0 – 110	2002 - 2005
IL	Renewable Energy Resources Rebate Program (Illinois Dept. Commerce & Economic Opportunity)	145	0.7	0.2%	0.8 – 60	1999 - 2007
MA	Small Renewables Initiative (Massachusetts Technology Collaborative)	702	4.7	1.3%	0.2 – 432	2002 - 2007
MD	Solar Energy Grant Program (Maryland Energy Administration)	78	0.2	0.1%	0.5 – 45	2005 - 2007
MN	Solar Electric Rebate Program (Minnesota State Energy Office)	105	0.4	0.1%	0.9 – 40	2002 - 2007
NJ	Customer Onsite Renewable Energy Program (New Jersey Clean Energy Program)	2,395	42.1	11.6%	0.8 – 702	2003 - 2007
NY	PV Incentive Program (New York State Energy Research & Development Authority)	755	4.4	1.2%	0.7 – 51	2003 - 2007
OR	Solar Electric Program (Energy Trust of Oregon)	600	2.3	0.6%	0.8 – 67	2003 - 2007
PA	Solar PV Grant Program (Sustainable Development Fund)	137	0.5	0.1%	1.2 – 10	2002 - 2007
WI	Cash Back Rewards Program (Wisconsin Focus on Energy)	240	0.9	0.2%	0.2 – 19	2002 - 2007
	Total	***36,992***	***363.1***	***100%***	***0.1 – 1,265***	***1998 - 2007***

[9] These five systems include: a 14.2 MW system installed in 2007 at Nellis Air Force Base in Nevada; two systems (8.2 MW and 2 MW) installed in Colorado in 2007; and two systems (4.6 MW and 3.4 MW) installed in Arizona, completed in 2004 and 2006, respectively.

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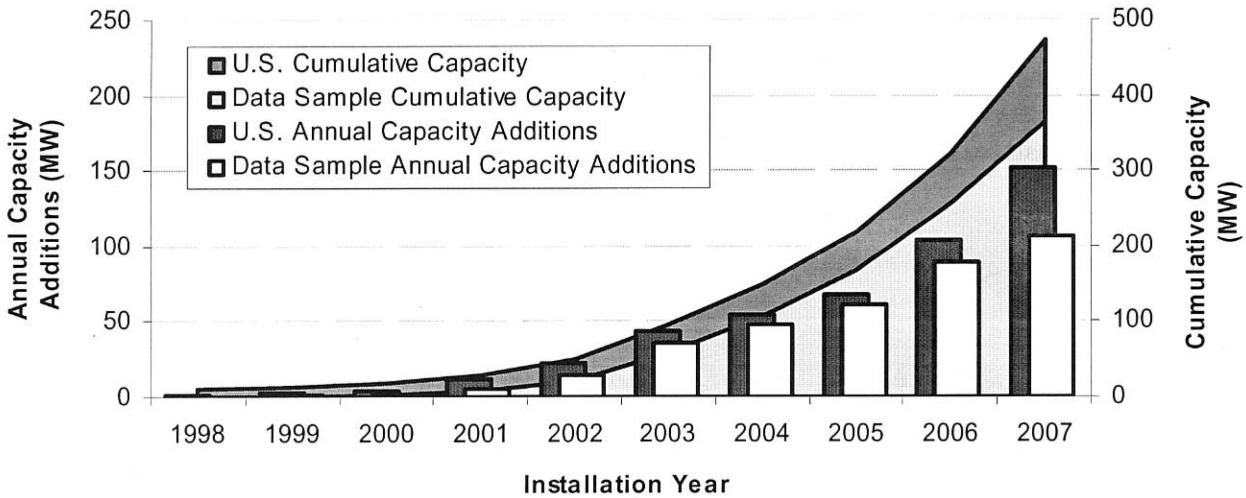

Figure 1. Data Sample Compared to Total U.S. Grid-Connected PV Capacity[10]

Table 2. Data Sample by Installation Year

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	Total
No. of Systems	39	190	219	1,344	2,523	3,471	5,497	5,084	8,353	10,272	**36,992**
% of Total	0.1%	0.5%	0.6%	3.6%	6.8%	9.4%	14.9%	13.7%	22.6%	27.8%	**100%**
Capacity (MW)	0.2	0.8	1.0	5.6	14.0	36.0	47.9	61.2	89.3	107.0	**363.1**
% of Total	0.1%	0.2%	0.3%	1.6%	3.9%	9.9%	13.2%	16.9%	24.6%	29.5%	**100%**

The PV systems in the primary dataset were installed over a ten-year period, from 1998 through 2007. As to be expected, however, given the dramatic expansion of the U.S. solar market over recent years, the sample is skewed towards projects completed during the latter years of this period (see Table 2). Approximately half of the PV systems in the sample were installed in either 2006 or 2007, and slightly more than half (54%) of the total capacity was installed during these two years.[11] See Appendix B for detailed annual installation data (number of systems and capacity) by PV incentive program and system size range.

Among the 16 PV incentive programs that provided data for this report, the lion's share of the sample is associated with the four largest PV incentive programs in the country to-date: California's Emerging Renewables Program (ERP); California's Self-Generation Incentive Program (SGIP); the California Solar Initiative (CSI) Program; and New Jersey's Customer Onsite Renewable Energy (CORE) Program. As such, the sample is heavily weighted towards systems installed in California and New Jersey, as shown in Figure 2. In terms of installed capacity, these two states represent 83% and 12% of the total data sample, respectively. Massachusetts, New York, Arizona, Connecticut, and Oregon each represent between 0.6-1.3% of the sample, with the remaining five states (Illinois, Maryland, Minnesota, Pennsylvania, and Wisconsin) comprising 0.9%, in total.

[10] Data source for U.S. Grid-Connected PV Capacity: Sherwood, L. 2008. *U.S. Solar Market Trends 2007*. Interstate Renewable Energy Council. http://www.irecusa.org.

[11] Dates used in this report are the system completion dates, or whatever date is provided that best approximates that date.

4-9

The size of the PV systems in the primary dataset span a wide range, from as small as 100 W to as large as 1.3 MW, but almost 90% of the projects in the sample are smaller than 10 kW (see Figure 3). In terms of installed capacity, however, the sample is considerably more evenly distributed across system size ranges, with systems larger than 100 kW representing 40% of the total installed capacity, and systems smaller than 10 kW representing 38%.

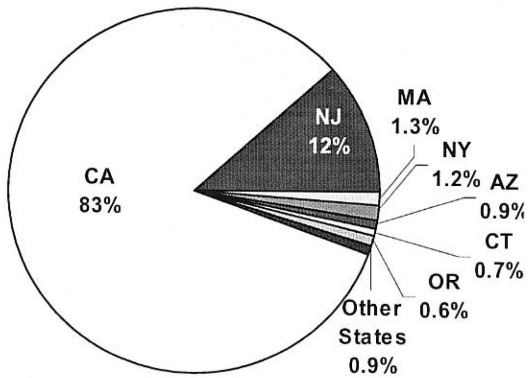

Figure 2. Data Sample Distribution among States (by Cumulative MW)

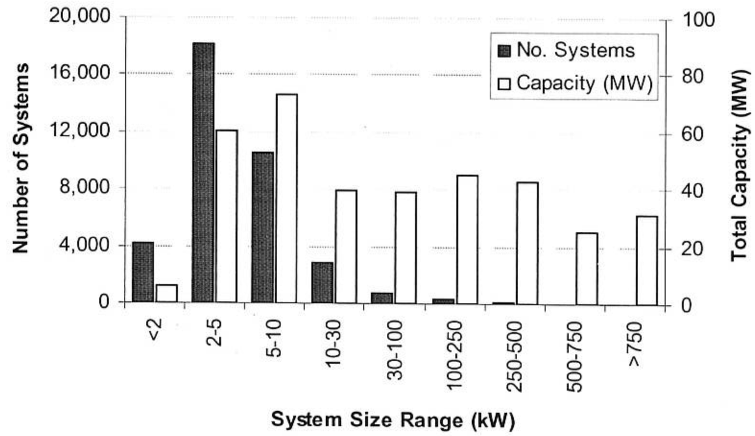

Figure 3. Data Sample Distribution by PV System Size

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3. PV Installed Cost Trends

This section presents the primary findings of the report, describing trends in the average installed cost of grid-connected PV, based on the dataset described in Section 2. It begins by presenting the trends in installed costs over time; by system size; between Japan, Germany, and the U.S.; and among individual states.[12] It then compares installed costs among several specific types of applications and technologies – specifically, residential new construction vs. residential retrofit, BIPV vs. rack-mounted systems, and systems with thin-film modules vs. those with crystalline modules. Last, the section presents some limited data related to component-level costs. To be clear, the focus of this section is on installed costs, as paid by the system owner, prior to receipt of any financial incentives (e.g., rebates, tax credits, etc.).

Installed Costs Have Declined over Time, but Were Stable from 2005-2007

Figure 4 presents the average installed cost of all projects in the primary sample completed in each year, from 1998-2007. As shown, capacity-weighted average costs declined from \$10.5/W in 1998 to \$7.6/W in 2007, equivalent to an average annual reduction of \$0.3/W, or 3.5%/yr in real dollars.

These cost reductions, however, have not occurred steadily over time. From 1998-2005, average costs declined at a relatively rapid pace, with average annual reductions of \$0.4/W, or 4.8% per year in real dollars. From 2005 through 2007, however, installed costs remained essentially flat. During this period, U.S. and global PV markets expanded significantly, creating shortages in the supply of silicon for PV module production and putting upward pressure on PV module prices. As documented in the next section, however, silicon shortages are not the sole cause for the cessation of price declines during 2005-2007, as average non-module costs also remained relatively flat over this period.

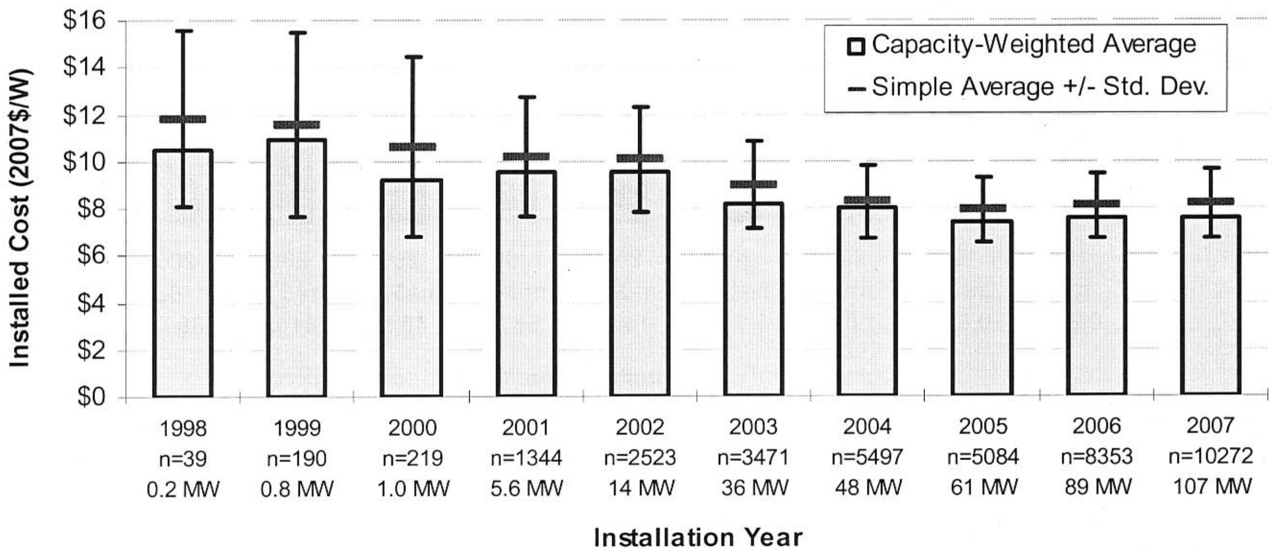


Figure 4. Installed Cost Trends over Time

[12] Unless otherwise noted, the results include all system types (e.g., rack-mounted, building-integrated, tracking, non-tracking, crystalline, non-crystalline, etc.).

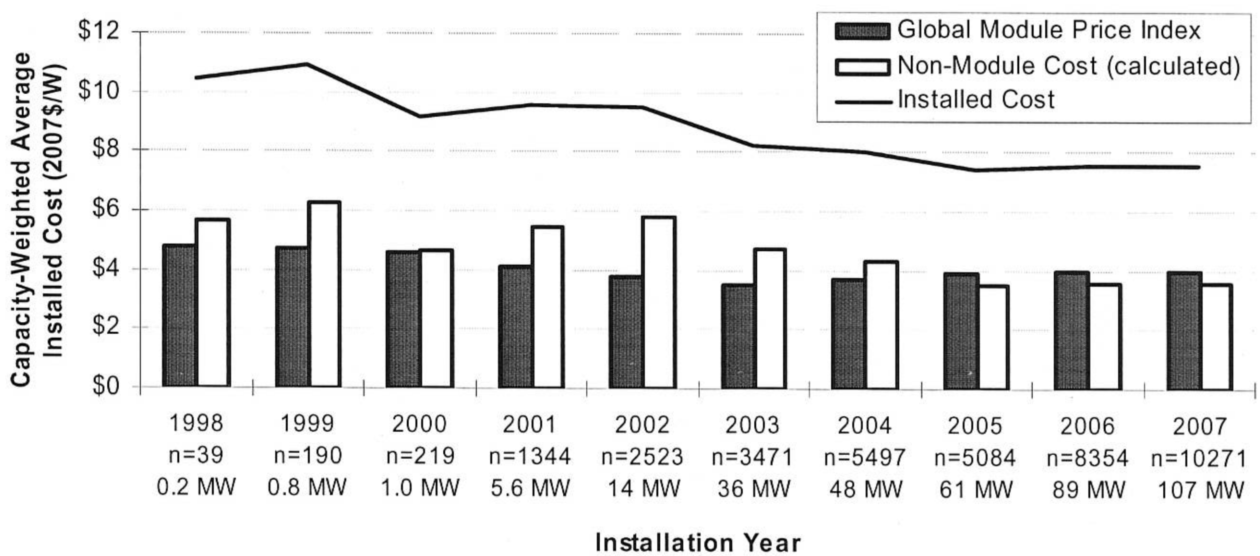
4-11

Installed Cost Reductions Are Primarily Associated with Non-Module Costs

Figure 5 disaggregates average annual installed costs into average module and non-module costs. Few programs provided actual component-level cost data. In lieu of this information, Figure 5 presents Navigant Consulting's Global Power Module price index as a proxy for module costs. The non-module costs (which may include such items as inverters, mounting hardware, labor, permitting and fees, shipping, overhead, taxes, and profit) shown in Figure 5 are then calculated as the difference between the average total installed cost and the module price index in each year.

Using this method, the decline in total average PV installed costs since 1998 appears to be primarily attributable to a drop in *non-module* costs, which fell from approximately \$5.7/W in 1998 to \$3.6/W in 2007, a reduction of \$2.1/W (or 73% of the \$2.9/W drop in total installed costs of this period). In comparison, module index prices dropped by only \$0.8/W from 1998-2007, and increased somewhat from 2003-2007.[13] As with the trend in total installed costs, however, average non-module costs remained relatively stable from 2005-2007.

Trends in non-module costs may be particularly relevant in gauging the impact of state and utility PV programs. Unlike module prices, which are primarily established through national (and even global) markets,[14] non-module costs consist of a variety of cost components that may be more readily affected by local programs – including both deployment programs aimed at increasing demand (and thereby increasing competition and efficiency among installers) as well as more-targeted efforts (e.g., training and education programs). Thus, the fact that non-module costs have fallen over time, at least until 2005, suggests (though, admittedly, does not prove) that state and local PV programs have had some success in driving down the installed cost of PV.



Note: Non-module costs are calculated as reported total installed costs minus the global module price index.

Figure 5. Module and Non-Module Cost Trends over Time

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[13] Other sources of historical PV module price data are available (e.g., SolarBuzz and Photon Consulting) and show qualitatively similar trends. For example SolarBuzz's retail module price index is approximately \$0.6/W lower in 2007 than at the end of 2001, with relatively constant prices from 2005-2007.

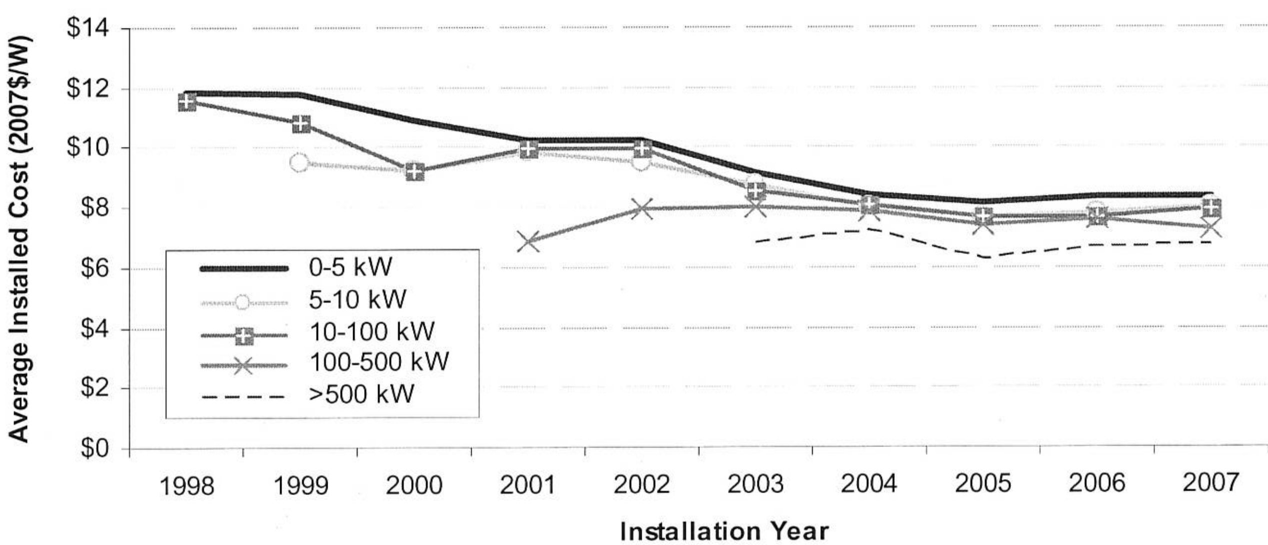
[14] PV modules are effectively commodities whose prices are established through the interplay of global supply and demand. Though average module prices can and do vary by region, those differences are likely to be considerably smaller than differences in non-modules costs.

4-12

Historical Cost Reductions Are Most Evident for Systems Smaller than 100 kW

The overall decline in average installed costs across the entire sample largely reflects the decline in costs of small and medium-size systems, as shown in Figure 6. From 1998-2007, the installed cost of systems <5 kW in size dropped from an average of $11.8/W to $8.3/W, equivalent to an average annual reduction of $0.4/W per year. Similar cost reductions occurred for 10-100 kW systems, and lower but still apparent cost reductions occurred for 5-10 kW systems. Larger systems (100-500 kW and >500 kW), however, did not exhibited a discernable reduction in average installed costs over this period.

These trends may, in part, be attributable to the fact that non-module costs, which declined more over time than module costs, comprise a larger portion of the overall cost of smaller systems (as documented later in this report, where component-level cost data are presented for different sizes). Some caution is warranted in interpreting the results for large systems, though, as relatively few of these systems were installed during the early years of the study period. For example, for 100-500 kW systems, fewer than 10 systems were installed each year until 2003; and for >500 kW systems, fewer than 10 systems were installed each year until 2006 (see Table B-2 in Appendix B for annual sample size data by system size).



Note: Averages shown only if more than five observations were available for a given size category in a given year.

Figure 6. Installed Cost Trends over Time, by PV System Size

The Distribution of Installed Costs Has Narrowed Over Time

As indicated by the standard deviation bars in Figure 4, the distribution of installed costs has narrowed considerably over time. This trend can be seen with greater precision in Figures 7 and 8, which present frequency distributions of installed costs for systems less than and greater than 10 kW, respectively, installed in different time periods. Both figures show a marked narrowing of the cost distributions over the past decade. This convergence of prices, with high-cost outliers becoming increasingly infrequent, is consistent with a maturing market characterized by increased competition among installers and module manufacturers, improved module manufacturing and installation efficiency, and better-informed consumers. The two figures also show a *shifting* of the

4-13

cost distributions to the left, as would be expected based on the previous finding that average installed costs have declined over time. As with the overall decline in average costs, however, the narrowing of the cost distribution has subsided within the past 3-4 years, with the distribution of installed costs remaining largely stable from 2004/05 to 2006/07.

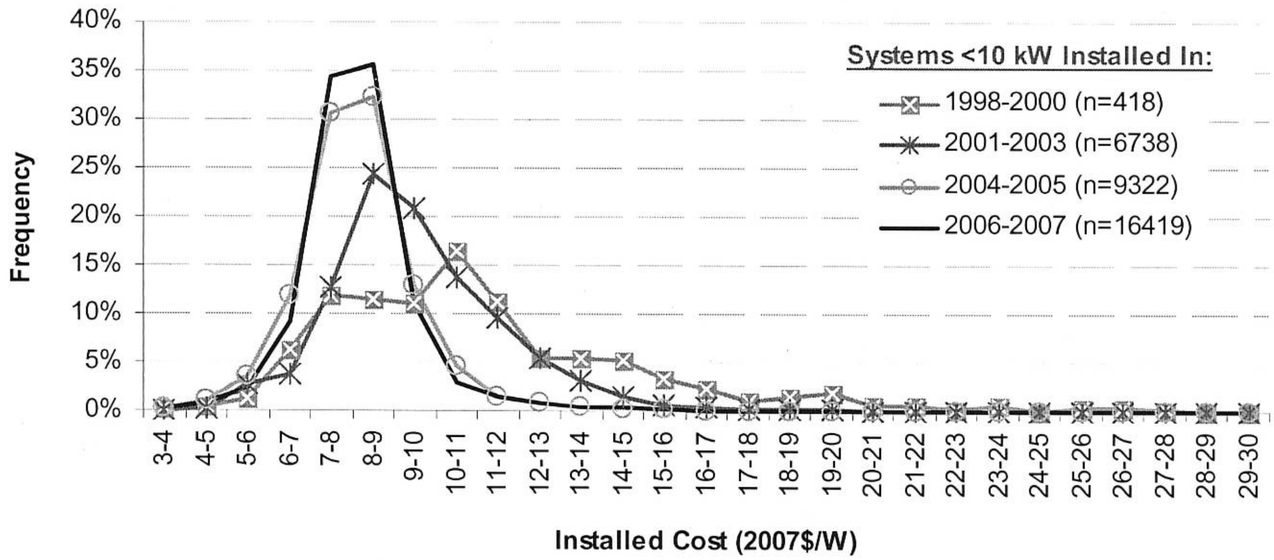


Figure 7. Distribution of Installed Costs for Systems <10 kW

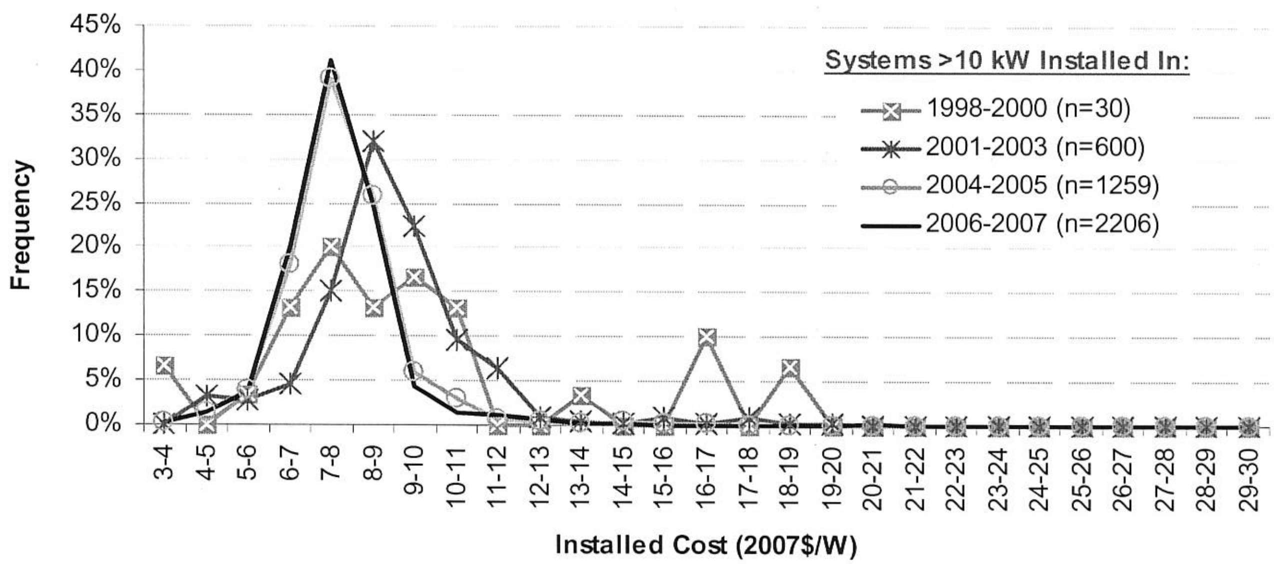


Figure 8. Distribution of Installed Costs for Systems >10 kW

Installed Costs Exhibit Significant Economies of Scale

Large PV installations may benefit from economies of scale, through price reductions on volume purchases of materials and through the ability to spread fixed costs (including transaction costs) over a larger number of installed watts. This expectation has been borne out in experience, as indicated by Figure 9, which shows the average installed cost according to system size, for PV

4-14

systems completed in 2006 and 2007. The smallest systems (<2 kW) exhibit the highest average installed costs ($9.0/W), while the largest systems (>750 kW) have the lowest average cost ($6.8/W, or about 25% below the average cost of the smallest systems). Interestingly, the economies of scale do not appear to be continuous with system size, but rather, most strongly accompany increases in system size up to 5 kW, and increases in system size in the 100-750 kW range. In contrast, the data do not show evidence of significant economies of scale within the 5-100 kW size range.

The primary dataset underlying the results shown in Figure 9 consists only of data provided by the 16 PV program administrators in our sample. Not included in this dataset are a number of large, multi-MW PV systems, several of which are installed on the utility-side of the meter. Installed cost data for five of these projects have been reported in press releases and other public sources, and are summarized in Table 3.[15] As shown, the installed costs of these projects are generally similar to the average cost of the >750 kW systems shown in Figure 9.[16] Importantly, though, a number of these out-of-sample multi-MW projects have tracking systems, and are therefore likely to attain higher performance (and thus lower levelized costs on a $/MWh basis) than the large projects in the primary dataset, which are mostly fixed-axis systems.

To the extent that the economies of scale described above have persisted over time, they may partially explain the temporal decline in average installed costs as the average size of PV systems has grown over time. As shown in Figure 10, the average size of systems <10 kW (a rough proxy for residential systems) grew from 2.7 kW in 1998 to 4.6 kW in 2007. Similarly, the average size of systems >10 kW (most of which are non-residential systems) rose from 25 kW to 55 kW over the same time period.

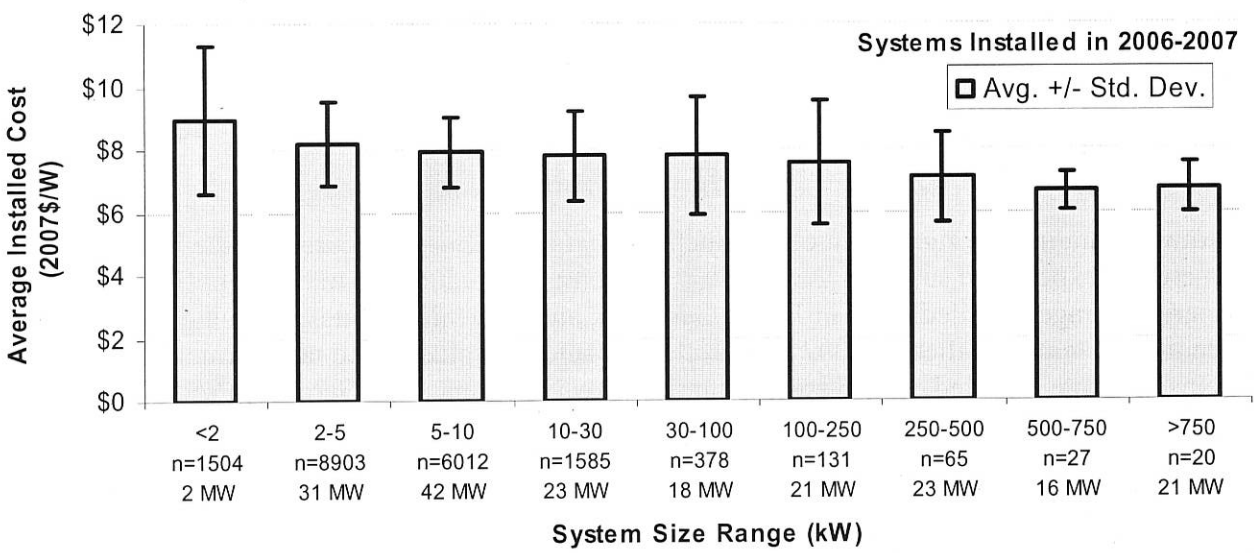


Figure 9. Variation in Installed Cost According to PV System Size

[15] Table 3 only includes systems >2 MW that are not in the primary dataset and for which installed cost data could be found. Note, though, that the sources of these cost data vary in quality, and therefore these data are less certain than the data in the primary sample.
[16] Though the focus of this report is on systems installed through 2007, it is worth noting that a number of utility-scale PV systems installed in 2008 are reported to have installed costs significantly below the average for >750 kW customer-sited systems installed in 2006/07.

4-15

Table 3. Installed Cost of Large PV Systems Not Included in the Primary Dataset

Location	Year of Installation	Plant Size (kW)	Installed Cost (2007$/W)	Actual or Expected Capacity Factor	Tracking System Design
Nellis, NV	2007	14,200	7.0	24%	single axis
Alamosa, CO	2007	8,220	7.3	24%	fixed, single axis, and double axis
Fort Carson, CO	2007	2,000	6.5	18%	fixed
Springerville, AZ	2001-2004	4,590	5.9	19%	fixed
Prescott Airport, AZ	2002-2006	3,388	5.4	21%	single axis and double axis

Notes: Cost for Springerville is for capacity added in 2004. Cost for Prescott is for single-axis capacity additions in 2004.

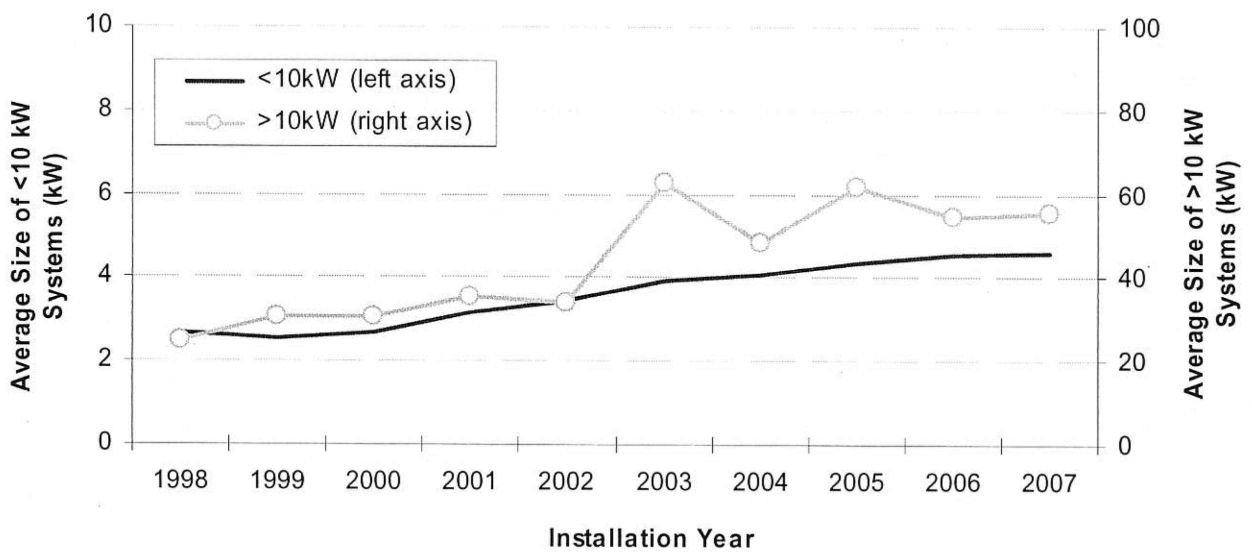


Figure 10. PV System Size Trends over Time

Average Installed Costs Are Lower in Germany and Japan than in the U.S.

Notwithstanding the significant cost reductions that have already occurred in the U.S., international experience suggests that greater near-term cost reductions may be possible. Figure 11 compares average installed costs in Japan, Germany, and the United States, focusing specifically on residential systems installed in 2007 (and excluding sales or value-added tax). Among this class of systems, average installed costs were substantially lower in Japan and Germany ($5.9/W and $6.6/W, respectively) than in the U.S. ($7.9/W). These differences may be partly attributable to the much greater cumulative grid-connected PV capacity in Japan and Germany (about 1,800 MW and 3,800 MW, respectively, at the end of 2007), compared to just 500 MW in the U.S. However, it is also evident that larger market size, alone, does not account for all of the variation – as indicated by the fact that installed costs are higher in Germany than in Japan, despite the substantially greater grid-connected PV capacity in the former.[17]

[17] The relatively low residential PV costs in Japan may be partly explained by the fact that Japan's PV support policies have focused largely on the residential sector, and that a large portion of this market consists of pre-fabricated new homes that incorporate PV systems as a standard feature. More generally, installed costs may differ among countries as a result of a wide variety of factors, including differences in: module prices, technical standards for grid-connected PV

4-16

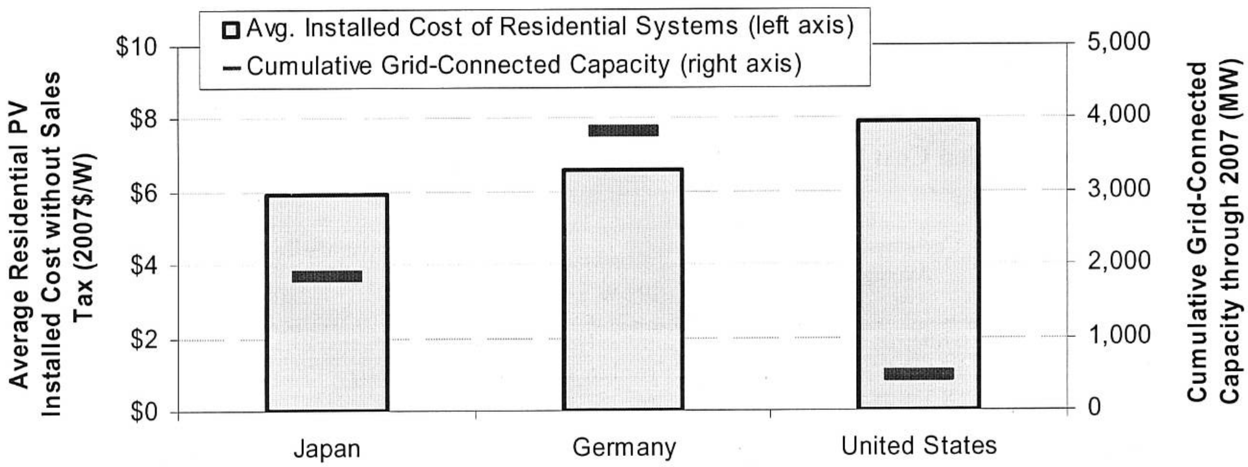


Figure 11. Comparison of Average Installed Costs in Japan, Germany, and the U.S. (Residential Systems Completed in 2007)[18]

Installed Costs Vary Widely Across States

The U.S. is clearly not a homogenous PV market, as evidenced by Table 4, which compares the average installed cost of systems completed in 2006 or 2007, across the 12 states in the dataset.[19] Figure 12 focuses specifically on systems less than 10 kW, for which there are a relatively large number of projects in each state. Among systems in this size class, average costs range from a low of $7.6/W in Arizona to a high of $10.6/W in Maryland.

This variation in average installed costs across states is, in part, likely a consequence of the differing size and maturity of the PV markets, where larger markets stimulate greater competition and hence greater efficiency in the delivery chain, and may also allow for bulk purchases and better access to lower-cost products. Most notably, the two largest PV markets in the U.S. – California and New Jersey – have among the lowest average costs, lending some credence to the premise behind state policies and programs that seek to reduce the cost of PV by accelerating deployment.[20]

As noted in the preceding comparison between the U.S., Japan, and Germany, however, other factors also drive differences in installed costs among individual states. Incentive application procedures and regulatory compliance costs, for example, vary substantially. Additionally, installed costs vary across states due to differing sales tax treatment; five of the 12 states shown in Figure 12 (Arizona, Massachusetts, Minnesota, New Jersey, and New York)[21] exempted PV hardware costs from state sales tax throughout 2006 and 2007, and Oregon has no state sales tax. If PV hardware costs represent approximately 60% of the total installed cost of residential PV systems (an

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systems, installation labor costs, procedures for receiving incentives and permitting/interconnection approvals, foreign exchange rates, and the degree to which components are manufactured locally.

[18] In Figure 11, the Japanese cost data are for 2-5 kW systems, while the German and U.S. cost data are for 3-5 kW systems. Additionally, note that the U.S. data presented in this figure exclude sales tax, and therefore are not entirely comparable to data presented elsewhere in this report, which include sales tax, if applicable. Sources for Japanese and German data: Ikki, O. and K. Matsubara. 2008. *National Survey Report of PV Power Applications in Japan 2007.* Paris, France: International Energy Agency Cooperative Programme on Photovoltaic Power Systems. Wissing, L. 2008. *National Survey Report of PV Power Applications in Germany 2007.* Paris: France: International Energy Agency Cooperative Programme on Photovoltaic Power Systems.

[19] See Appendix B for average annual cost data for each of the 16 PV incentive programs.

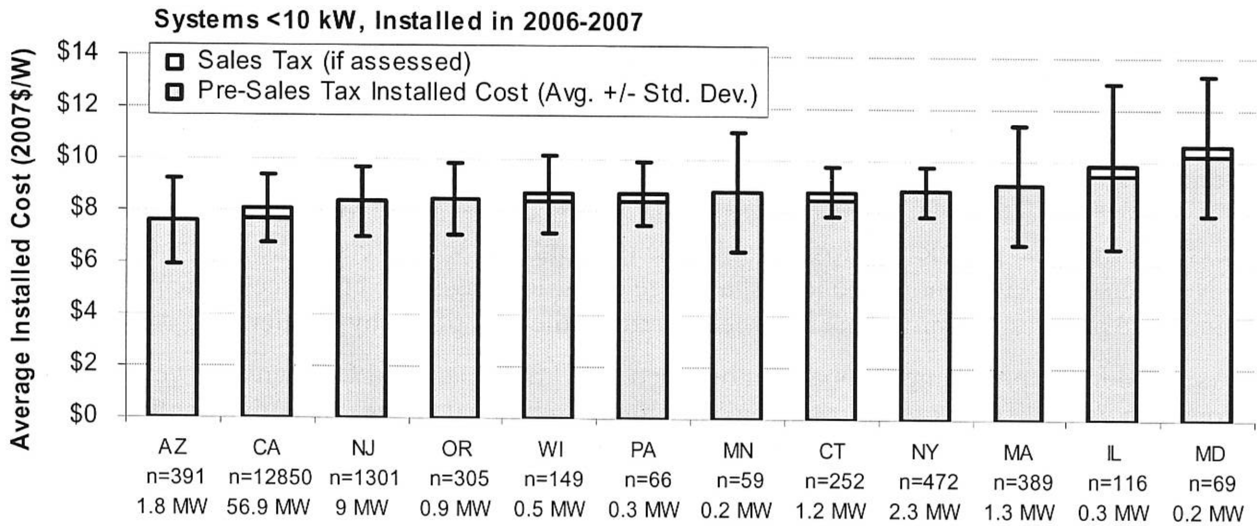
[20] The reason for the relatively low average cost in Arizona – itself a smaller PV market – is unknown.

[21] Connecticut established a state sales tax exemption for PV beginning in July 2007.

assumption supported by data presented later in this report), sales tax exemptions effectively reduce post-sales-tax installed costs by \$0.2-0.4/W, depending on the state sales tax rate.

Table 4. Average Installed Cost by State and PV System Size Range

State	Total Sample Capacity-Weighted Average Cost		2006-2007 Systems										
			Capacity-Weighted Average Cost (all sizes)		Simple Average Cost							
					0 - 10 kW		10 - 100 kW		100 - 500 kW		>500 kW	
AZ	\$7.8	(n=540)	\$7.6	(n=413)	\$7.6	(n=391)	\$8.1	(n=20)	\$9.1	(n=2)	n/a	(n=0)
CA	\$7.7	(n=30963)	\$7.5	(n=14614)	\$8.1	(n=12850)	\$7.6	(n=1607)	\$7.3	(n=136)	\$6.7	(n=33)
CT	\$8.4	(n=311)	\$8.3	(n=274)	\$8.8	(n=252)	\$8.1	(n=19)	\$7.9	(n=3)	n/a	(n=0)
IL	\$12.4	(n=166)	\$8.5	(n=118)	\$9.8	(n=116)	\$3.3	(n=2)	n/a	(n=0)	n/a	(n=0)
MA	\$9.7	(n=702)	\$9.6	(n=415)	\$9.1	(n=389)	\$10.1	(n=24)	\$8.8	(n=5)	n/a	(n=0)
MD	\$9.8	(n=78)	\$9.7	(n=71)	\$10.6	(n=69)	\$8.5	(n=2)	n/a	(n=0)	n/a	(n=0)
MN	\$8.4	(n=105)	\$8.5	(n=60)	\$8.8	(n=59)	\$8.7	(n=3)	n/a	(n=0)	n/a	(n=0)
NJ	\$7.7	(n=2395)	\$7.5	(n=1588)	\$8.4	(n=1301)	\$8.4	(n=272)	\$7.6	(n=50)	\$6.7	(n=15)
NY	\$8.8	(n=755)	\$8.8	(n=519)	\$8.8	(n=472)	\$8.9	(n=52)	n/a	(n=0)	n/a	(n=0)
OR	\$8.0	(n=600)	\$8.4	(n=324)	\$8.4	(n=305)	\$8.4	(n=19)	n/a	(n=0)	n/a	(n=0)
PA	\$9.0	(n=137)	\$8.7	(n=67)	\$8.7	(n=66)	\$8.4	(n=1)	n/a	(n=0)	n/a	(n=0)
WI	\$8.4	(n=240)	\$8.3	(n=162)	\$8.7	(n=149)	\$7.9	(n=16)	n/a	(n=0)	n/a	(n=0)



Note: Sales tax, if assessed on customer-sited PV installations in 2006-07, was assumed to be applied to only hardware costs, which were assumed to constitute 60% of the total pre-sales-tax installed cost.

Figure 12. Variation in Installed Costs among U.S. States

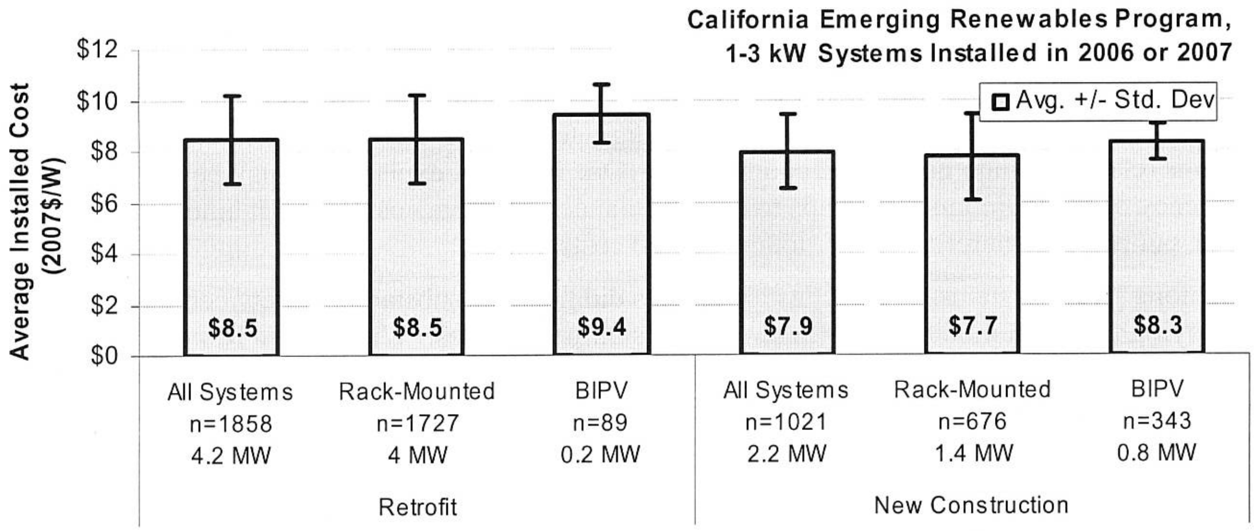
The New Construction Market Offers Cost Advantages for Residential PV

The California Emerging Renewables Program (ERP) is one of few PV incentive programs within the sample that explicitly tracks which of the funded systems are installed in residential new construction applications.[22] Figure 13 compares the average installed cost of residential new construction and residential retrofit projects funded through the ERP, focusing in particular on 1-3

[22] Note that, starting in 2007, the California Energy Commission's New Solar Homes Program (NSHP) replaced the ERP as the incentive program for PV systems installed in residential new construction (within the service territories of California's investor-owned utilities). No systems funded through the NSHP were completed in 2007, however.

4-18

kW projects (the size range typical of residential new construction) completed in 2006 or 2007. Among this group of PV systems, those installed in residential new construction cost \$0.6/W less, on average, than comparably-sized residential retrofit systems (\$7.9/W compared to \$8.5/W), a price advantage of approximately 7%.[23]



Note : The number of rack-mounted systems plus BIPV systems may not sum to the total number of systems, as some systems could not be identified as either rack-mounted or BIPV.

Figure 13. Comparison of Installed Costs for Residential Retrofit vs. New Construction

Simply comparing the overall average cost of all residential new construction and all residential retrofit systems masks the fact that a much larger proportion of new construction systems are building-integrated PV (BIPV), which tend to have somewhat higher costs than rack-mounted systems, thought the higher installed costs may be partially offset by avoided roofing material costs. To allow an apples-to-apples comparison, Figure 13 also presents average costs for rack-mounted and BIPV systems within both the new construction and retrofit samples. Systems were identified as BIPV or rack-mounted based on module manufacturer and model data provided for the ERP-funded systems. These comparisons suggest a somewhat greater cost advantage for new construction than implied by the overall averages, with rack-mounted systems installed in residential new construction averaging \$0.8/W less than residential retrofit systems (\$7.7/W compared to \$8.5/W), and BIPV systems in new construction averaging \$1.1/W less than residential retrofits (\$8.3/W compared to \$9.4/W).[24]

[23] For this report, we have not attempted to distinguish between PV systems installed in large new residential developments and those installed on individual custom new homes. This issue was explored in a previous Berkeley Lab report: Wiser, R., M. Bolinger, P. Cappers, and R. Margolis. 2006. *Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California*. LBNL-59282. Berkeley, California: Lawrence Berkeley National Laboratory. That earlier report used data from the ERP and a multi-variate linear regression analysis, and found that the cost differential between residential new construction and retrofit markets was much greater for large new developments than for individual new homes. Specifically, PV systems installed in large new residential developments were found to cost \$1.2/W_{AC} (\$1.0/$W_{DC\text{-}STC}$) less, on average, than residential retrofit systems, while systems installed on individual new homes cost just \$0.18/W_{AC} (\$0.15/$W_{DC\text{-}STC}$) less than retrofit systems.

[24] Some caution is warranted in interpreting the cost comparison for BIPV systems. Individual PV systems in the ERP dataset were identified as BIPV using module manufacturer and model data provided for these systems. Because some

4-19

Small Systems with Thin-Film Modules Had Higher Installed Costs in 2006 and 2007 than Those with Crystalline Modules

Module manufacturer and model data were provided for approximately half of the systems in the dataset, and were used to determine whether these systems employed thin-film or crystalline modules.[25] As shown in Figure 14, thin-film systems <10 kW in size and installed in 2006 or 2007 had average installed costs $0.5/W higher than comparably-sized crystalline systems.[26] This result comes as somewhat of a surprise given that thin-film modules are widely considered to be lower cost than crystalline, and that greater uncertainty in the long-term performance of thin-film modules, on the part of consumers, would seemingly tend to drive down the price of thin-film systems relative to their crystalline counterparts. One potential explanation may be that the lower efficiency of thin-film modules leads to higher balance of system costs, at least among the systems in our sample, and therefore higher total installed costs.

Among larger systems, average installed costs did not vary substantially between those employing thin-film modules and those with crystalline modules. Within the >100 kW size category shown in Figure 14, thin-film systems appear to be substantially more costly than crystalline systems ($7.7/W, compared to $7.1/W for crystalline systems). However, this apparent trend is an artifact of the small sample size and the presence of a single thin-film system with an installed cost of $25/W. If this system were eliminated from the data set, the average cost of the thin-film systems >100 kW would be $7.2/W – only marginally higher than the corresponding value for crystalline systems.

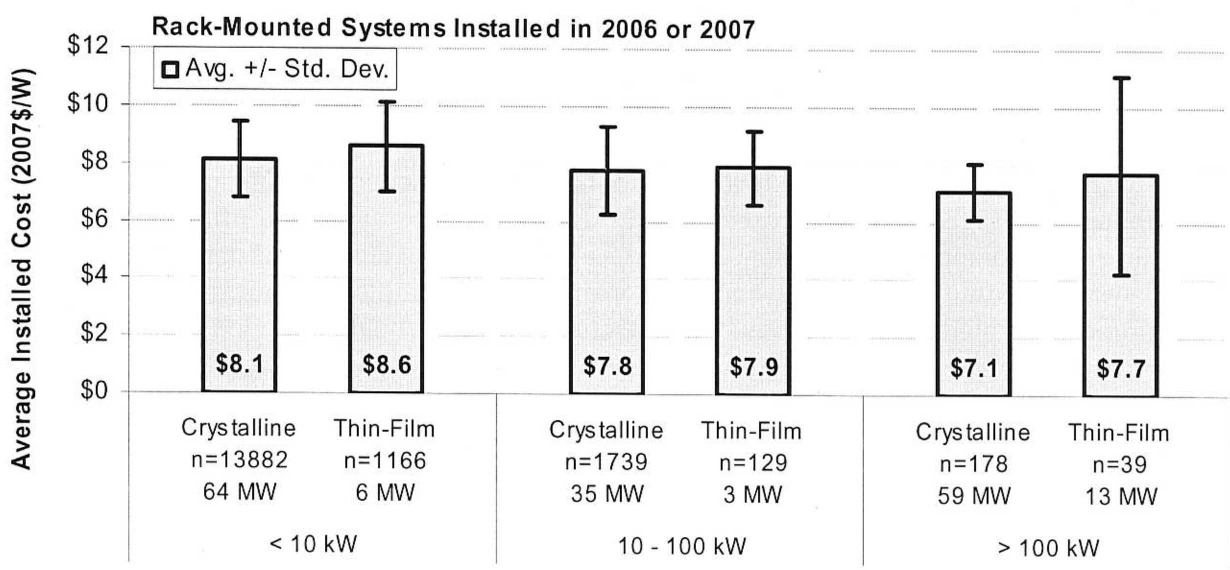


Figure 14. Comparison of Installed Costs for Crystalline vs. Thin-Film Systems

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modules made for BIPV applications may be installed as rack-mounted systems, it is possible (if not likely) that some of the systems identified as residential retrofit BIPV systems may be misclassified and may, in fact, be rack-mounted installations.

[25] Thin-film systems include both amorphous silicon and non-silicon modules.

[26] For the purpose of this comparison, we compare rack-mounted crystalline to rack-mounted thin-film (i.e., we exclude BIPV systems.

4-20

Module Costs Represent About Half of Total PV Installed Costs, with the Remainder Consisting of a Diversity of Non-Module Cost Components

The average module and non-module costs presented previously in Figure 5 were estimated based on a module price index. This approach was necessitated by the fact that many of the PV incentive programs in our data sample did not provide component-level cost data. However, a few programs did provide component-level cost data, and this limited quantity of data do lend some validation to the break-down between module and non-module costs implied in Figure 5, and also provide a moderate level of additional detail on the composition of non-module costs. Figure 15 summarizes the limited amount of component-level cost data provided by the PV incentive programs in our data sample, for <10 kW and 10-100 kW systems completed in 2006-2007. For both system size ranges, modules represent slightly over 50% of total costs, on average – which is roughly consistent with the imputed module cost indicated in Figure 5 – while inverter costs average just under 10% of total costs. "Other" costs (e.g., mounting hardware, labor, overhead, profit, etc.) make up the relatively substantial remaining portion of total installed costs.

Some additional detail on individual component costs, although not based directly on project data, can be gleaned from the results of a survey of PV installers conducted by Berkeley Lab in 2008. The survey asked installers to provide the typical percentage contribution to total cost for a variety of specific cost components (e.g., modules, inverters, installation labor, etc.). As shown in Figure 16, installers reported that module costs typically represent approximately 50% of total installed cost, and inverters represent 6-7% of total costs – findings that are generally consistent with the component cost data reported by PV incentive program administrators, which are based on actual system installations. The survey results also provide further granularity in decomposing non-module, non-inverter costs. In particular, the survey results indicate that, depending on the system size, installation labor represents 9-10% of total installed cost, and other materials (e.g., mounting hardware) represent 7-11% of installed cost. The remaining 20-29% of installed costs consists of overhead, profit, and regulatory compliance (e.g., permitting, interconnection, rebate application). Not surprisingly, these "other" costs – many of which are largely fixed costs – represent a greater percentage of total installed costs for residential systems than for larger, non-residential systems.

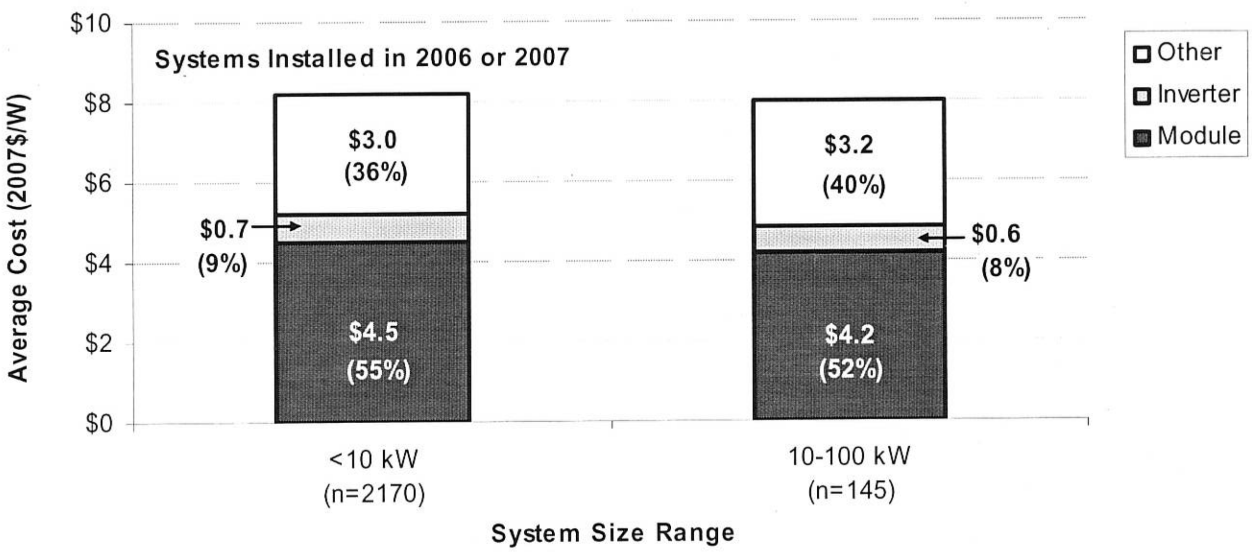
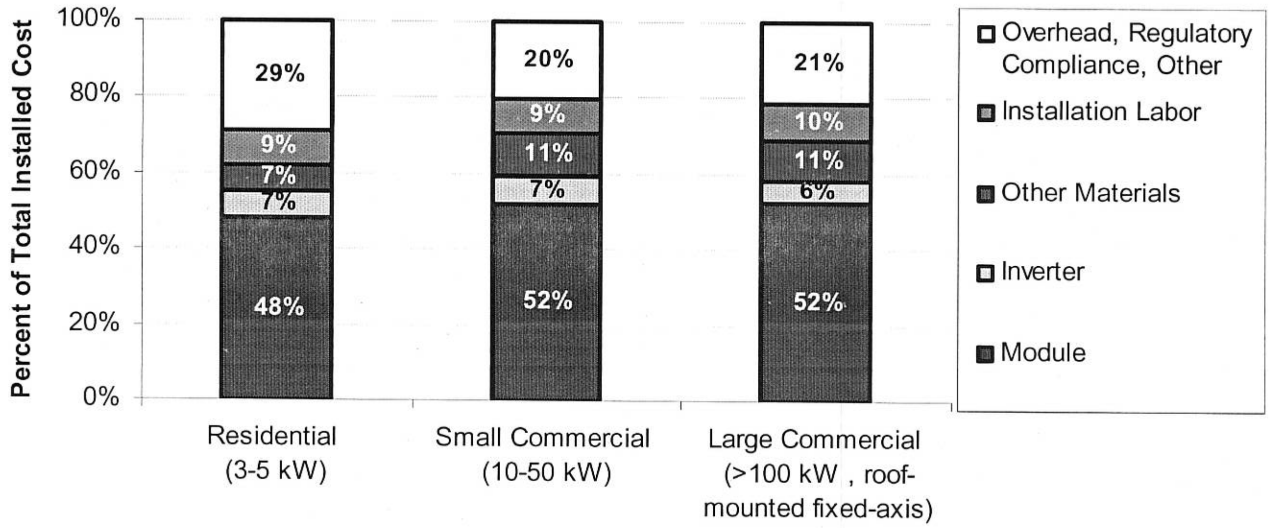


Figure 15. Module, Inverter, and Other Costs

4-21



Sample size: six installers provided survey responses for residential and large commercial systems, and five installers provided survey responses for small commercial systems.

Figure 16. Results from Berkeley Lab Survey of PV Installers on Component Costs

4-22

4. PV Incentive and Net Installed Cost Trends

Financial incentives provided through utility, state, and Federal programs have been a major driving force for the PV market in the U.S. These incentives potentially include some combination of cash incentives provided through state or utility PV incentive programs, Federal and/or state investment tax credits (ITCs), revenues from the sale of renewable energy certificates (RECs), and accelerated depreciation of capital investments in solar energy systems. This section describes trends in incentive levels (focusing specifically on state/utility incentives and ITCs) and net installed costs (i.e., installed costs after receipt of financial incentives) over time, by system size, and among states.

Two important caveats should be noted at the outset:

- First, the set of incentives addressed here are necessarily limited in scope, accounting only for the direct cash incentives provided through the 16 state/utility incentive programs in the dataset, plus state and Federal ITCs. The analysis does not account for the incentive for commercial PV provided through accelerated depreciation (which has remained constant over the sample period),[27] nor for any additional incentives that projects may have received from state/utility incentive programs outside of the 16 program covered in this report.[28] The results presented in this section also do not account for revenue from the sale of RECs, although the potential magnitude of this revenue stream is briefly discussed in general terms (see Text Box 1).
- Second, this section marks a departure from Section 3 by going beyond a simple reporting of the data provided by program administrators. In particular, a variety of assumptions, as documented within this section and described further in Appendix C, were required in order to estimate the value of Federal and state ITCs for each project and to determine the net installed cost on an after-tax basis.

State/Utility Cash Incentives Have Declined since 2002

The 16 state and utility PV incentive programs represented within the dataset provide cash incentives of varying forms. Most provide up-front cash incentives (i.e., "rebates"), based either on system capacity, a percentage of installed cost, or a projection of annual energy production. Several programs, instead, provide performance-based incentives (PBIs), which are paid out over time based on actual energy production, as either a supplement or an alternative to an up-front rebate.[29] Figure 16 shows the average cash incentive, on a $/W basis, received by the PV systems in the dataset, over time and according to system size. These data are presented on a *pre-tax* basis – that

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[27] Commercial PV owners are allowed to depreciate the installed cost of their system over a 5-year schedule, rather than the standard 20-year period. The net present value of this accelerated depreciation (relative to the standard depreciation schedule) is equal to 12% of installed costs. See: Bolinger, M., G. Barbose, and R. Wiser. 2008. *Shaking Up the Residential PV Market: Implications of Recent Changes to the ITC.* Berkeley, CA: Lawrence Berkeley National Laboratory.

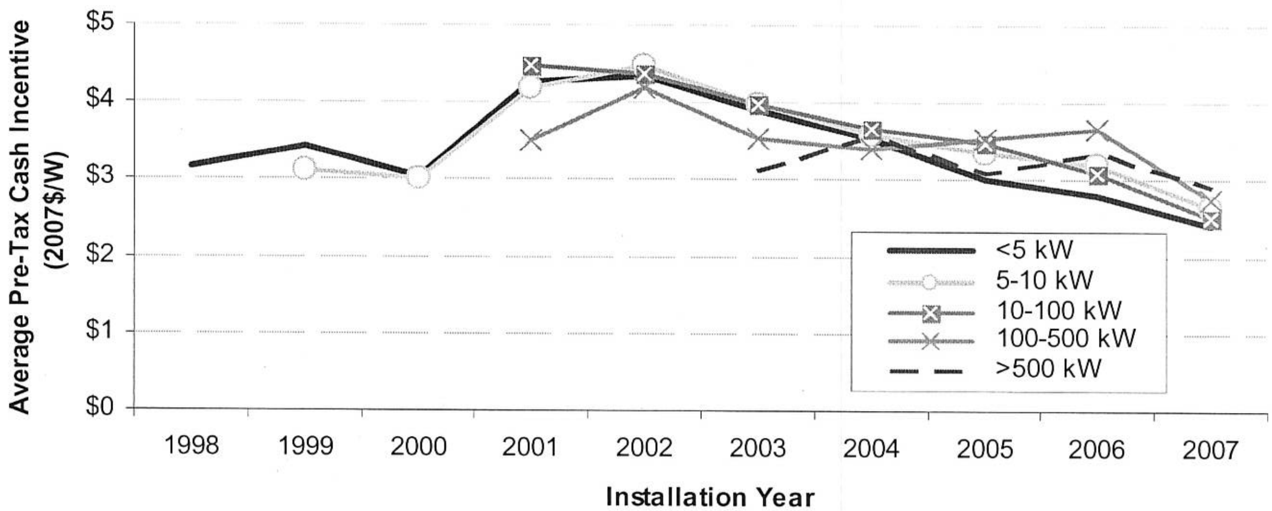
[28] For example, in Pennsylvania, some projects may have received incentives through both the Sustainable Energy Fund's Solar Grant Program and the state's Energy Harvest Program (where the former is included in the dataset and the latter is not).

[29] PBI payments were reported by PV incentive program administrators on a $/W basis, based on estimated energy production. These $/W figures were used directly, without discounting, in the analysis provided in this section.

4-23

is, prior to assessment of state or Federal taxes that may be levied if the incentive is treated as taxable income.[30]

As shown, average cash incentives declined significantly from 2002-2007 across all size ranges (with the exception of the >500 kW category, for which insufficient data are available for 2002). Specifically, cash incentives declined from 2002-2007 by an average of $1.9/W for systems in the <5 kW, 5-10 kW, and 10-100 kW size ranges, and by $1.4/W for systems 100-500 kW.[31] These trends largely reflect changes in incentive levels within California's Emerging Renewables Program (ERP) and Self-Generation Incentive Program (SGIP), which together represent approximately 75-80% of all systems in each size category. To some extent, these incentive level trends also reflect the growing prominence of New Jersey's Customer-Onsite Renewable Energy (CORE) program, which has offered relatively high incentives. The CORE program represents an increasing percentage of the sample in all size categories over time, counteracting, to some degree, the decline in average incentive levels associated with the drop in ERP and SGIP incentives. Although masked by the dominant effect of the California and New Jersey programs, average incentives among the other PV incentive programs also generally declined since 2002/2003 (see Table B-3 in Appendix B). Last, it is perhaps interesting to note that, although the difference is relatively small, the largest systems in the sample (>500 kW) received the highest incentives, on average, in 2007 ($2.9/W), while the smallest systems (< 5 kW) received the lowest average incentives in that year ($2.4/W).



Note: Averages shown only if more than five observations available for a given size range in a given year.

Figure 16. Pre-Tax State/Utility Cash Incentive Levels over Time

[30] Although the IRS has provided only limited guidance on the issue, it appears that, in most cases, cash incentives provided for commercial PV systems are considered Federally-taxable income. Cash incentives for residential PV, however, are exempt from Federal income taxes if the incentive is considered to be a "utility energy conservation subsidy," per Section 136 of the Internal Revenue Code. Despite several IRS private letter rulings of potential relevance, uncertainty remains as to what exactly constitutes a "utility energy conservation subsidy." See: Bolinger, M., G. Barbose, and R. Wiser. 2008. *Shaking Up the Residential PV Market: Implications of Recent Changes to the ITC.* Berkeley, CA: Lawrence Berkeley National Laboratory.

[31] For systems >500 kW, the maximum average incentive was $3.6/W in 2004, declining to $2.9/W in 2007 (a drop of $0.7/W). However, fewer than 10 systems in this size range were installed each year prior to 2006, and therefore the time trend is rather idiosyncratic and not particularly meaningful.

4-24

Text Box 1. Revenue from the Sale of RECs

PV system owners may be able to sell RECs generated by their system, adding to any direct incentives received from state/utility PV incentive programs and Federal or state ITCs (provided that REC ownership is not automatically transferred to the state/utility as a condition of receiving a direct cash incentive). Projecting the value of REC sales over the lifetime of each individual PV system in our dataset would be a highly speculative task, and therefore was not undertaken for this study. Based on historical REC prices, however, the revenue potential in most states (with the exception of New Jersey) is relatively modest, compared to the value of direct cash incentives received through state/utility PV incentive programs and to the value of the Federal ITC for commercial PV.

In general, the potential REC revenue for customer-sited PV depends on where the system is located, and consequently, what types of REC markets are available.

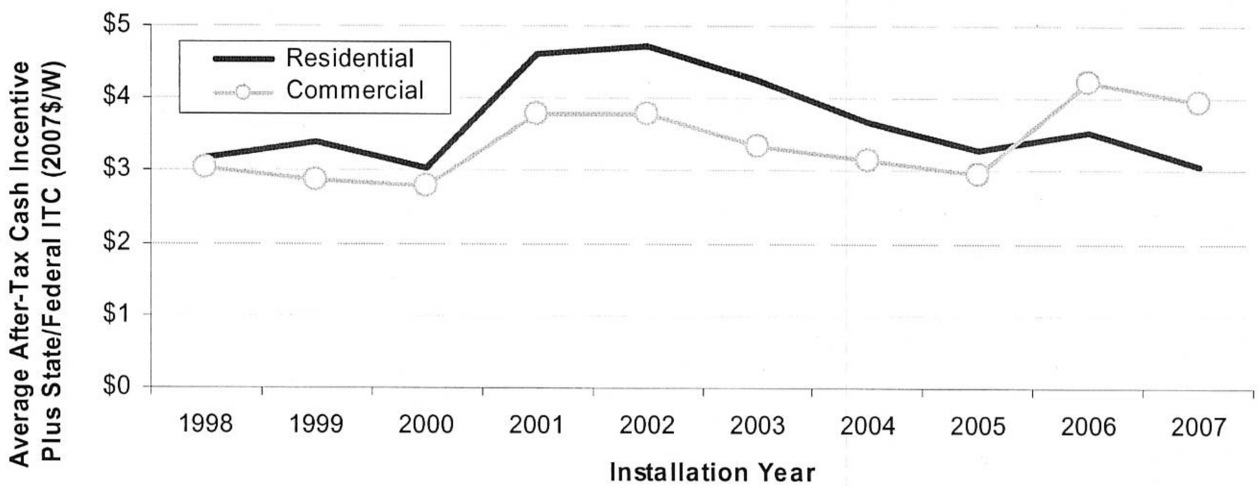
- *Voluntary REC Markets.* In most states, RECs generated by PV systems may be sold to individuals, businesses, or government agencies that are voluntarily seeking to support renewable energy and/or to publicly demonstrate their support. Given the voluntary nature of these transactions, prices in voluntary REC markets have historically been quite modest. For example, voluntary RECs traded through Evolution Markets, a brokerage firm, averaged about $20/MWh in 2007. Extrapolated over a 20-year period, revenues from REC sales at this price are equivalent to just $0.23/W on a present value basis (assuming a 10% nominal discount rate and a capacity factor of 14%), without accounting for income tax that may be assessed on REC revenue.
- *Traditional RPS Markets.* In some states, RECs generated by PV systems may be sold to electricity suppliers for compliance with state renewables portfolio standards (RPS). These markets may offer greater REC revenue potential, though REC prices in RPS markets have historically varied quite substantially across states and over time. For PV, the most critical issue typically is whether the state RPS has a specific solar requirement (i.e., a "solar set-aside"). In traditional RPS markets without a solar set-aside, the highest average REC prices in 2007 (based on trading through Evolution Markets) occurred in Massachusetts, where REC prices for compliance with the state's Class I RPS requirement averaged approximately $55/MWh. Extrapolating these prices over a 20-year period (using the same assumptions as before) is equivalent to an up-front, pre-tax payment of $0.63/W.
- *RPS Solar Set-Aside Markets.* Substantially greater REC revenue potential may be available in states with an RPS solar set-aside. Through 2007, active trading of solar RECs (or SRECs) for compliance with a solar set-aside occurred primarily in New Jersey, where SRECs traded through Evolution Markets averaged $253/MWh in 2007. Again, extrapolating this revenue stream over a 20-year period yields the equivalent of an up-front, pre-tax payment of $2.9/W (equal to roughly 60% of the average pre-tax cash incentive paid by New Jersey's CORE Program for PV systems installed in 2007). As of 2009, however, systems larger than 50 kW in New Jersey are no longer eligible for cash incentives, as the state shifts towards an SREC-based support mechanism.

Including Federal and State ITCs, Financial Incentives Rose for Commercial PV from 2002-2007, But Fell for Residential PV

Although direct cash incentives received from state and utility PV programs have, on average, declined over time, other sources of financial incentives have become more significant. Most notably, starting January 1, 2006, the Federal ITC for commercial PV systems rose from 10% to 30% of project costs, and a 30% ITC (capped at $2,000) was established for residential PV. (Note that the *Energy Improvement and Extension Act of 2008* lifted the cap on the residential ITC for

4-25

systems installed on or after January 1, 2009; however, this change does not pertain to the systems within our sample.) In addition to the Federal ITC, a number of states have, at various times, also offered state ITCs for PV, although these tax credits have generally been smaller and/or available to a more-restricted set of projects than the Federal tax credit (see Appendix C for details on the ITCs for PV offered by the states in our dataset).



Notes: We assume that all systems <10 kW are residential (unless indentified otherwise) and that state/utility cash incentives for such systems are non-taxable and reduce the basis of the Federal ITC. We assume that all systems >10 kW are commercial (unless indentified otherwise) and that state/utility cash incentives for such systems are taxed at a Federal corporate tax rate of 35% plus the prevailing state corporate tax rate, and do not reduce the basis of the Federal ITC. The value of state ITCs is calculated as described in Appendix C.

Figure 17. After-Tax State/Utility Cash Incentives plus State & Federal ITCs (Estimated)

Figure 17 illustrates the combined effect of changes over time in state and Federal ITCs (assuming that all customers take advantage of available tax credits) *plus* changes in the cash incentives provided through the state and utility PV incentive programs in the dataset, expressed here on an *after-tax* basis. As noted previously, this assessment ignores potential revenues from the sale of RECs, though for most of the 12 states in our dataset (other than New Jersey), such revenues would likely add only marginally to the overall incentive received (see Text Box 1).

Figure 17 suggests a notably different trend for commercial PV systems than that exhibited in Figure 16 for systems >10 kW (the majority of which are commercial). Specifically, as shown in Figure 17, the decline in the average combined commercial incentive that began in 2002 abruptly reversed course in 2006, when the Federal ITC for commercial PV increased from 10% to 30% of project costs. As a result, commercial PV systems received *greater* total financial incentives in 2006-2007, on average, than at any time since 1998, with the after-tax value of cash incentives plus ITCs averaging $3.9/W in 2007. Residential PV also saw a slight boost in overall incentive levels when the Federal ITC was extended to these systems in 2006; however, with the $2,000 cap on the residential credit, the effect was much less dramatic than for commercial PV.[32] Consequently, the

[32] Removal of the $2,000 ITC cap for residential systems installed on or after January 1, 2009 will, of course, provide an additional increase in residential incentives. Even after the cap is lifted, however, the average value of the residential ITC will still be less than the commercial ITC, because utility rebates for residential systems are often tax-exempt and therefore reduce the tax credit basis on which the ITC applies.

4-26

combined after-tax incentive (cash incentives plus ITCs) for residential PV was, in 2007, at its lowest average level ($3.1/W) since 2001.

The fact that combined after-tax incentives rose substantially from 2005-2007 for commercial PV, while remaining essentially flat for residential PV, may partially explain the shift towards the commercial sector within the U.S. PV market over this period. With the lifting of the cap on the Federal ITC for residential PV beginning in 2009, however, some movement back towards the residential sector may occur.

Declining Financial Incentives for Residential PV Offset Much of the Cost Reductions from 2001-2007, While Net Installed Costs for Commercial PV Continued to Fall

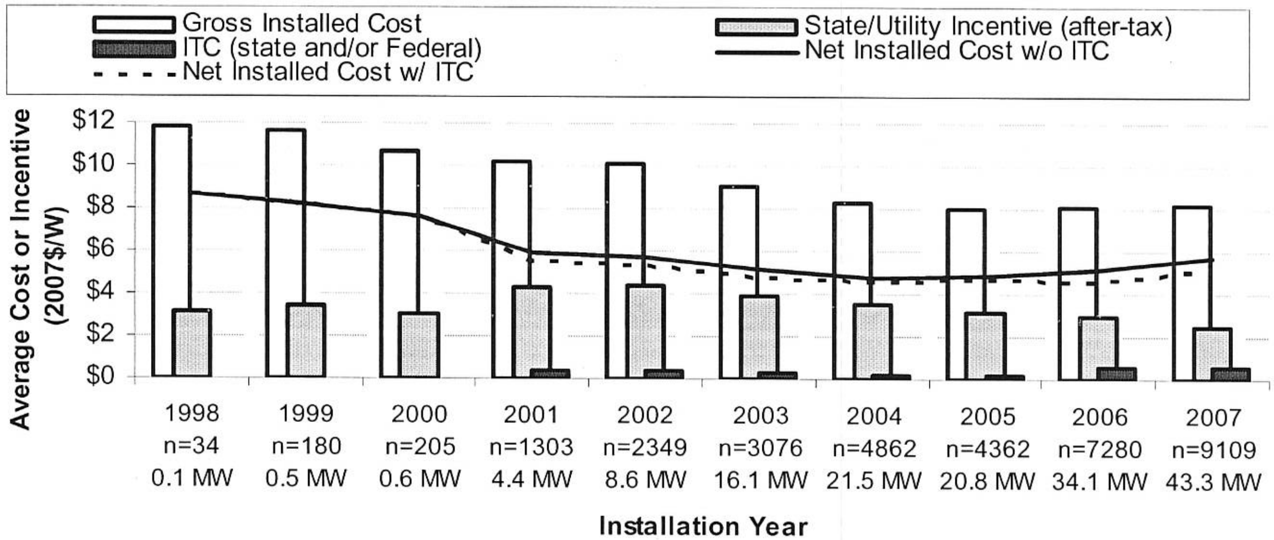
As discussed at length in Section 3, average installed costs across most PV system size categories declined significantly from 1998-2005, but remained relatively stable from 2005-2007. At the same time, average after-tax incentive levels for residential systems steadily declined from 2002-2007. The net effect of these two trends, as illustrated in Figure 18, is that the net installed cost of residential PV – that is, the installed cost after deducting the after-tax value of state/utility cash incentives plus ITCs – has remained relatively flat since 2001, declining by $1.0/W from 2001-2004, and then increasing by $0.5/W from 2004-2007. Thus, in 2007, the average net installed cost of residential PV was $5.1/W, compared to an average of $5.6/W in 2001, a drop of just 7%.

As shown in Figure 19, the trend for commercial PV is markedly different, by virtue of the more-lucrative Federal ITC available beginning in 2006. Specifically, in 2007, the net installed cost of commercial PV was $3.9/W, compared to $5.9/W in 2001, a drop of 32%. Without Federal and state ITCs, though, the average net installed cost of commercial PV would be only 9% lower in 2007 than in 2001 ($6.3/W compared to $7.0/W), and would be essentially unchanged from the average net installed cost in 2003 ($6.2).

Finally, Figures 18 and 19 also illustrate the potential impact of incentive levels on gross (i.e., pre-incentive) installed costs. A previous Berkeley Lab report, *Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California*, found a statistically significant correlation between pre-incentive installed costs in California and incentive levels under the state's two major PV incentive programs at the time (ERP and SGIP).[33] Evidence of this correlation can be seen in Figures 18 and 19 (not surprisingly so, given the dominance of ERP and SGIP systems within the dataset). Most visibly, the decline in gross installed costs that had occurred during prior years ceased in 2001-2002, especially among commercial systems, coinciding with a substantial increase in incentive levels under the ERP and SGIP.

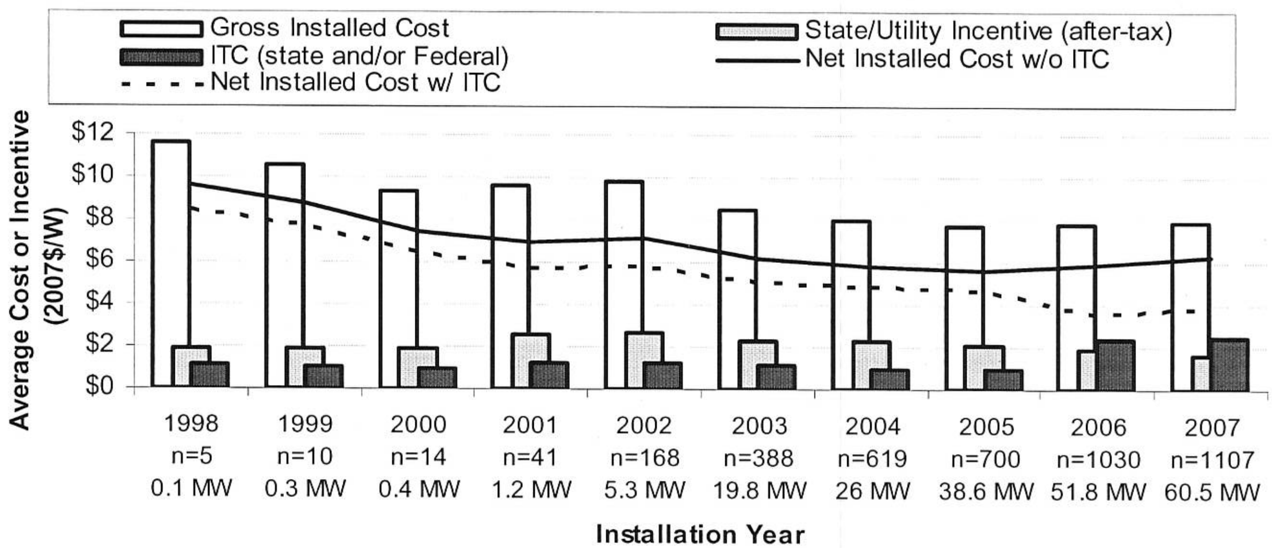
[33] Wiser, R., M. Bolinger, P. Cappers, and R. Margolis. 2006. *Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California.* LBNL-59282. Berkeley, California: Lawrence Berkeley National Laboratory.

4-27



Notes: We assume that all systems <10 kW are residential (unless identified otherwise) and that state/utility cash incentives for such systems are non-taxable and reduce the basis of the Federal ITC. The value of state ITCs is calculated as described in Appendix C.

Figure 18. Net Installed Cost of Residential PV over Time (Estimated)



Notes: We assume that all systems >10 kW are commercial (unless identified otherwise) and that state/utility cash incentives for such systems are taxed at a Federal corporate tax rate of 35% plus the prevailing state corporate tax rate, and do not reduce the basis of the Federal ITC. The value of state ITCs is calculated as described in Appendix C.

Figure 19. Net Installed Cost of Commercial PV over Time (Estimated)

Incentives Have Diverged Widely Across States

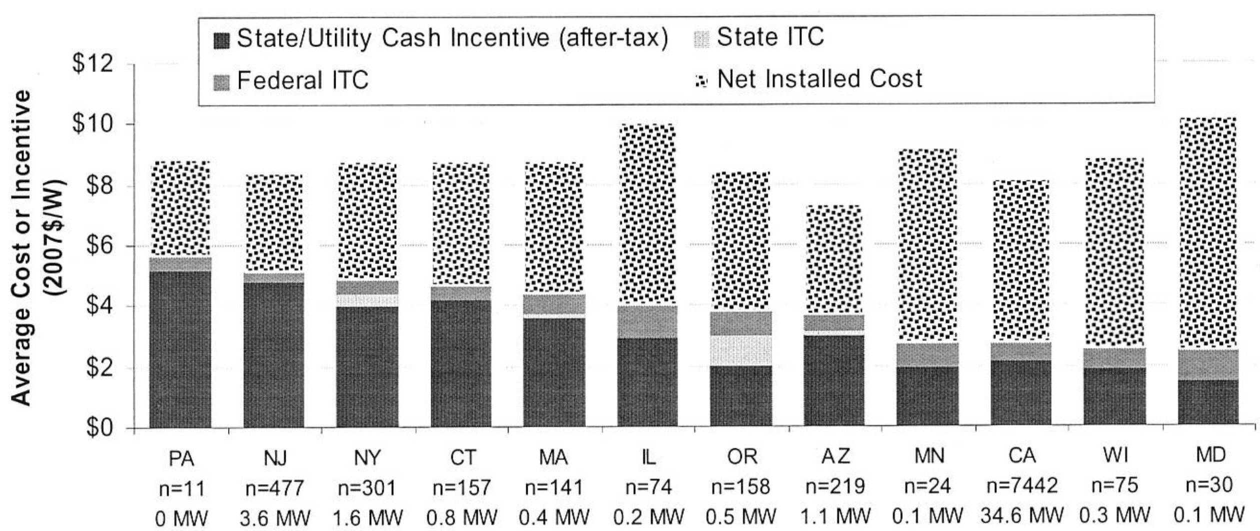
The preceding time trends apply to the sample at large, which is itself dominated by the PV incentive programs in California and New Jersey. Of course, incentives and net installed costs vary significantly from state-to-state, as shown in Figures 20 and 21, which compare average incentive levels and net installed costs across the 12 states in our dataset, focusing specifically on systems

4-28

installed in 2007.[34] Again, note that this analysis does not capture all types of financial incentives that may be available to PV systems in each state (e.g., incentives offered by other PV incentive programs outside of the 16 programs included in the data sample, and revenue that may be available from the sale of RECs).

Among residential systems installed in 2007 (Figure 20), average after-tax incentives (i.e., the sum of direct cash incentives from state/utility PV incentive programs plus state and Federal ITCs, but excluding revenue from sale of RECs) ranged from a high of $5.7/W in Pennsylvania to just $2.5/W in Maryland. These two states also represent the bookends in terms of net installed cost after incentives, averaging $3.2/W and $7.7/W, respectively. The largest PV markets, California and New Jersey, also fall at opposite ends of the spectrum. In California, after-tax incentives for residential PV averaged $2.8/W in 2007, yielding an average net installed cost of $5.4/W. In New Jersey, which offered a much more lucrative cash incentive in 2007, the combined after-tax incentive for residential PV averaged $5.1/W, yielding an average net installed cost of $3.3/W.

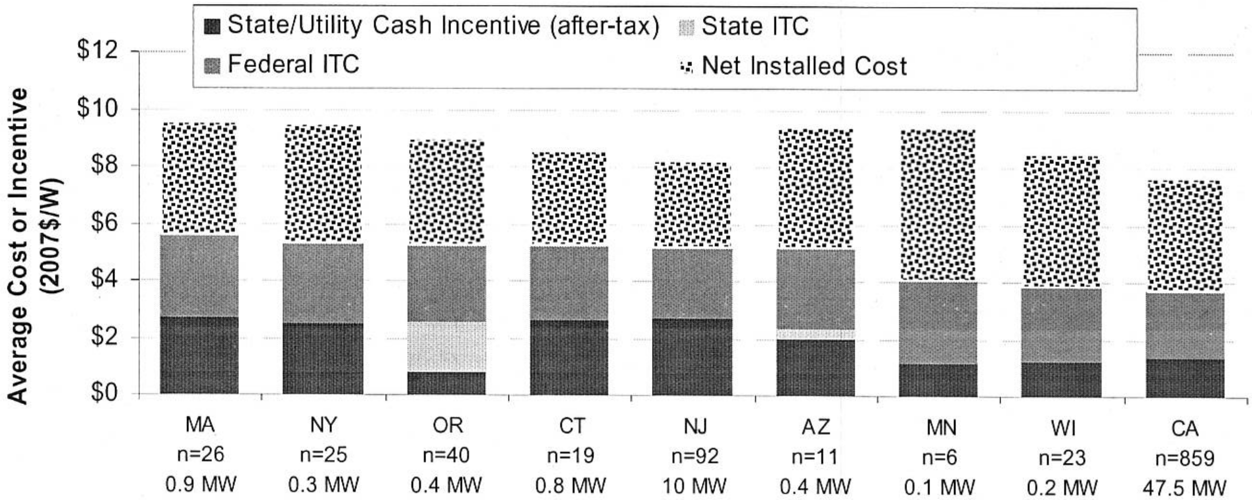
For commercial PV (Figure 21), average after-tax incentive levels and net installed costs also varied considerably across states in 2007. Comparing only those states within the dataset that had five or more commercial systems completed in 2007 (which excludes Pennsylvania and Maryland, the two bookends from the residential comparison, as well as Illinois), average after-tax incentives for commercial PV in 2007 ranged from $5.6/W in Massachusetts to $3.7/W in California. The lowest average net installed cost belongs to New Jersey, at $3.0/W (not accounting for SRECs, which, as discussed in Text Box 1, could reduce net installed costs by a substantial additional amount). In comparison, the net installed cost of commercial PV in 2007 was greatest in Minnesota, at $5.4/W.



Notes: We assume that all systems <10 kW are residential (unless identified otherwise) and that state/utility cash incentives for such systems are non-taxable and reduce the basis of the Federal ITC. The value of state ITCs is calculated as described in Appendix C.

Figure 20. Comparison of Incentive Levels and Net Installed Cost across States for Residential PV Systems Installed in 2007 (Estimated)

[34] See Appendix B for data on the average annual cash incentive for each of the 16 PV incentive programs.



Notes: IL , MD , and PA are omitted from the figure due to insufficient sample size (<5 systems). We assume that all systems >10 kW are commercial (unless identified otherwise) and that state/utility cash incentives for such systems are taxed at a Federal corporate tax rate of 35% plus the prevailing state corporate tax rate, and do not reduce the basis of the Federal ITC. The value of state ITCs is calculated as described in Appendix C.

Figure 21. Comparison of Incentive Levels and Net Installed Cost across States for Commercial PV Systems Installed in 2007 (Estimated)

4-30

5. Conclusions

Installations of photovoltaic systems have been growing at a rapid pace in recent years, driven in large measure by government incentives. Given the relatively high cost of PV, a key goal of these policies has been to encourage cost reductions over time. Out of this goal arises the need for reliable information on the historical installed cost of PV. This report addresses this need, describing trends in the installed cost of approximately 37,000 grid-connected systems deployed across 12 states from 1998-2007.

Available evidence confirms that PV costs have declined substantially over time, especially among smaller systems, primarily as a result of reductions in non-module costs. This trend, along with the narrowing of cost distributions over time, suggests that PV deployment policies have achieved some success in fostering competition within the industry and in spurring improvements in the cost structure and efficiency of the delivery infrastructure. Moreover, the fact that states with the largest PV markets also appear to have somewhat lower average costs than most states with smaller markets lends further credence to the premise that state and utility PV deployment policies can affect local costs. Even lower average installed costs in Japan and Germany suggest that deeper near-term cost reductions may be possible.

Despite these findings, both module and non-module costs remained largely unchanged from 2005-2007, perhaps reflecting constraints throughout the supply-chain and delivery infrastructure as PV markets rapidly expanded. This trend, were it to continue indefinitely, would be cause for concern, given the desire of PV incentive programs to continue to ratchet down the level of financial support offered to PV installations. Recent developments, however, portend a potentially dramatic shift over the next few years, with significant improvements in the customer-economics of PV. First, in contrast to the recent past, most industry experts anticipate an over-supply of PV modules in the near future, putting downward pressure on module prices in 2009 and, hence, on total installed costs (though projections of the magnitude of these price reductions vary considerably). Second, the lifting of the cap on the Federal ITC for residential PV, also beginning in 2009, will further reduce net installed costs for residential installations (to the extent that it is not offset by corresponding reductions in state and utility incentives). Although large commercial PV installations may continue to be the dominant growth market (joined by utility-scale PV), the removal of the cap on the residential ITC may lead to some degree of renewed emphasis on the residential market in the years ahead.

Appendix A: Data Cleaning, Coding, and Standardization

To the extent possible, this report presents the data as provided directly by PV incentive program administrators. That said, several steps were taken to clean the data and standardize it across programs, described below.

Projects Removed from the Dataset: The initial data sample received from PV incentive program administrators consisted of 37,249 PV systems installed through 2007. To eliminate presumably erroneous numerical data entries, systems were removed from the dataset if the reported installed cost was less than $3/W (13 systems) or greater than $30/W (28 systems), or if the incentive amount was zero (27 systems) or greater than the installed cost (17 systems). In addition, systems missing installed cost data (31 systems), incentive data (6 systems), or system size data (71 systems) were removed from the dataset. Finally, 74 systems with battery back-up were removed from the dataset. In total, 267 systems, out of an initial sample of 37,185, were removed from the dataset as a result of these filters, yielding a final sample of 36,992 systems.

Manual Data Cleaning: City, installer, zip code, module manufacturer/model, and inverter manufacturer/model data were reviewed in order to correct obvious misspellings and misidentifications, and to create standardized identifiers for individual module and inverter models.

Completion Date: The data provided by several PV incentive programs did not identify the system completion date. In lieu of this information, the best available proxy was used (e.g., the date of the incentive payment or the post-installation site inspection).

Identification of Residential New Construction and Residential Retrofit Systems: Section 3 compares the cost of systems installed in residential new construction to those installed in residential retrofit applications, focusing specifically on 1-3 kW systems funded through the California Energy Commission (CEC)'s Emerging Renewables Program (ERP) and installed in 2006 or 2007. Residential new construction systems were identified within the ERP dataset if the data field labeled "Category" contained the value "Development," "New Home," or "n".

Identification of Building-Integrated and Rack-Mounted Residential Systems: The comparison between residential new construction and residential retrofit systems funded through the ERP is further differentiated between building-integrated PV (BIPV) and rack-mounted systems. The raw data provided by the CEC did not include explicit identifiers for these categories; thus, systems were identified as either BIPV or rack-mounted by cross-referencing data provided on the module manufacturer and model for each system with the California Solar Initiative (CSI)'s List of Eligible Modules, which explicitly identifies whether modules are BIPV or rack-mounted.[35] Based on this procedure, 2,835 of the 2,879 applicable systems (i.e., 1-3 kW systems funded through the ERP in 2006 or 2007) were identified as either BIPV or rack-mounted.

Identification of Crystalline and Thin-Film Systems: Section 3 compares the installed cost of systems with thin-film modules to those with crystalline modules. The raw data provided by PV program administrators generally do not include explicit identifiers for these categories. Thus, systems were categorized as thin-film or crystalline by cross-referencing data provided on module manufacturer and model with the CSI's List of Eligible Modules, which explicitly identifies whether modules are crystalline or thin-film. Based on this procedure, 32,035 of the 36,992 systems were identified as employing either thin-film or crystalline modules.

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[35] http://www.gosolarcalifornia.org/equipment/pvmodule.php

Conversion to 2007 Real Dollars: Installed cost and incentive data are expressed throughout this report in real 2007 dollars (2007$). Data provided by PV program administrators in nominal dollars were converted to 2007$ using the "Monthly Consumer Price Index for All Urban Consumers," published by the U.S. Bureau of Labor Statistics.

Conversion of Capacity Data to DC Watts at Standard Test Conditions (DC-STC): Throughout this report, all capacity and dollars-per-watt ($/W) data are expressed using DC-STC capacity ratings. Most of the capacity data were already provided in units of DC-STC; however, two programs (California's Emerging Renewables Program and Self-Generation Incentive Program) provided capacity data only in terms of the CEC-AC rating convention. Capacity data from these two programs were converted to STC-DC, according to the procedures described below.

Emerging Renewables Program (ERP): The data provided for the ERP included data fields identifying the module manufacturer, model, and number of modules for most PV systems. DC-STC module ratings were identified for most systems by cross-referencing the information provided about the module type with the CSI's 2008 List of Eligible Photovoltaic Modules, which identifies DC-STC ratings for most of the modules employed by systems funded through the ERP. The DC-STC module rating for each system was then multiplied by the number of modules to determine the total DC-STC rating for the system, as a whole. This approach was used to determine the DC-STC capacity rating for 86% of the systems in the ERP dataset. For the remaining systems, either the module data fields were incomplete, or the module could not be cross referenced with the CSI list, or the estimated DC-STC rating for the system was grossly inconsistent with the reported CEC-AC rating. In these cases, an average conversion factor of 1.200 $W_{DC\text{-}STC}/W_{CEC\text{-}AC}$ was used, which was derived based on the other systems in the ERP dataset.

Self-Generation Incentive Program (SGIP): The data provided for the SGIP included data fields identifying the module manufacturer and model (but not number of modules), and inverter manufacturer and model. DC-STC module ratings and DC-PTC module ratings (i.e., DC watts at PVUSA Test Conditions) were identified for most SGIP projects by cross-referencing the information provided about the module type with the CSI's 2008 List of Eligible Photovoltaic Modules. Similarly, the rated inverter efficiency for each project was identified by cross referencing the information provided about the inverter type with the CSI's 2008 List of Eligible Inverters, which identifies inverter efficiency ratings for most of the inverters employed by systems funded through the SGIP.[36] For 16% of the systems in the SGIP dataset, data on the inverter manufacturer and model either was not provided or could not be matched with the CSI's list. In these cases, an average inverter efficiency of 92% was used, which was derived based on the other systems in the SGIP dataset.

These pieces of information (module DC-STC rating, module DC-PTC rating, and inverter efficiency rating), along with the reported CEC-AC rating for the system, were used to estimate the system DC-STC rating according to the following:

$$\text{System}_{DC\text{-}STC} = (\text{System}_{CEC\text{-}AC} / \text{Inverter Eff.}) * (\text{Module}_{DC\text{-}STC} / \text{Module}_{DC\text{-}PTC})$$

This approach was used to determine the DC-STC capacity rating for 68% of the systems in the SGIP dataset. For the remaining systems, either the module data fields were incomplete, or the module could not be cross referenced with the CSI list, or the estimated DC-STC rating for the system was grossly inconsistent with the reported CEC-AC rating. In these cases, an average conversion factor of 1.204 $W_{DC\text{-}STC}/W_{CEC\text{-}AC}$ was used, which was derived based on the other systems in the SGIP dataset.

[36] http://www.gosolarcalifornia.org/equipment/inverter.php

Appendix B: Detailed Sample Size Summaries

Table B-1. Program-Level Annual Installation Data, Based on Final Study Sample

State	Program Administrator(s) and Program Name		1998	1999	2000	2001	2002	2003	2004	2005
AZ	AZ Public Service: Solar Partners Incentive Program	*No. Systems*	-	-	-	-	4	9	42	72
		MW	-	-	-	-	0.01	0.1	0.2	0.4
CA	CA Energy Commission: Emerging Renewables Program	*No. Systems*	39	178	213	1,236	2,243	2,964	4,542	3,869
		MW	0.2	0.7	0.9	4.8	9.8	15.1	22.4	20.5
	Pacific Gas & Electric, Southern Calif. Edison, Calif. Center for Sustainable Energy: Self Generation Incentive Program	*No. Systems*	-	-	-	-	17	99	160	212
		MW	-	-	-	-	2.4	15.1	19.6	30.9
	Pacific Gas & Electric, Southern Calif. Edison, Calif. Center for Sustainable Energy: California Solar Initiative	*No. Systems*	-	-	-	-	-	-	-	-
		MW	-	-	-	-	-	-	-	-
	Los Angeles Dept. of Water & Power: Solar Incentive Program	*No. Systems*	-	3	4	103	232	150	24	61
		MW	-	0.01	0.1	0.6	1.5	4.7	1.6	1.8
CT	CT Clean Energy Fund: Solar PV and Onsite Renewable DG Programs	*No. Systems*	-	-	-	-	-	1	2	34
		MW	-	-	-	-	-	0.003	0.03	0.2
IL	IL Clean Energy Community Foundation: Renewable Energy Grant Programs	*No. Systems*	-	-	-	-	7	4	8	2
		MW	-	-	-	-	0.2	0.1	0.3	0.1
	IL Dept. of Commerce and Economic Opportunity: Renewable Energy Resources Rebate Program	*No. Systems*	-	9	2	5	5	-	3	3
		MW	-	0.02	0.03	0.2	0.2	-	0.05	0.003
MA	MA Technology Collaborative: Small Renewables Initiative	*No. Systems*	-	-	-	-	1	69	128	89
		MW	-	-	-	-	0.02	0.3	0.6	0.8
MD	MD Energy Administration: Solar Energy Grant Program	*No. Systems*	-	-	-	-	-	-	-	7
		MW	-	-	-	-	-	-	-	0.02
MN	MN State Energy Office: Solar Electric Rebate Program	*No. Systems*	-	-	-	-	1	9	23	12
		MW	-	-	-	-	0.002	0.02	0.1	0.03
NJ	NJ Clean Energy Program: Customer Onsite Renewable Energy Program	*No. Systems*	-	-	-	-	-	34	281	492
		MW	-	-	-	-	-	0.2	2.1	5.5
NY	NY State Energy Research and Development Authority: PV Incentive Program	*No. Systems*	-	-	-	-	-	43	98	95
		MW	-	-	-	-	-	0.2	0.5	0.6
OR	Energy Trust of Oregon: Solar Electric Program	*No. Systems*	-	-	-	-	-	54	135	87
		MW	-	-	-	-	-	0.1	0.4	0.3
PA	PA Sustainable Development Fund: Solar PV Grant Program	*No. Systems*	-	-	-	-	3	17	28	22
		MW	-	-	-	-	0.01	0.1	0.1	0.1
WI	WI Focus on Energy: Cash Back Rewards Program	*No. Systems*	-	-	-	-	10	18	23	27
		MW	-	-	-	-	0.02	0.03	0.1	0.1
	Total	*No. Systems*	***39***	***190***	***219***	***1,344***	***2,523***	***3,471***	***5,497***	***5,084***
		MW	***0.2***	***0.8***	***1.0***	***5.6***	***14.0***	***36.0***	***47.9***	***61.2***

4-34

Table B-2. Sample Size by Installation Year and System Size Range

System Size Range	Installation Year								
	1998	1999	2000	2001	2002	2003	2004	2005	2006
No. Systems									
0-5 kW	31	167	180	1,141	1,889	2,235	3,389	2,891	4,643
5-10 kW	3	13	24	159	459	855	1,534	1,508	2,685
10-100 kW	5	9	14	38	163	320	521	578	912
100-500 kW	-	1	1	6	9	55	46	98	92
>500 kW	-	-	-	-	3	6	7	9	21
Total	*39*	*190*	*219*	*1,344*	*2,523*	*3,471*	*5,497*	*5,084*	*8,353*
Capacity (MW)									
0-5 kW	0.1	0.4	0.4	3.1	5.0	6.3	9.8	8.6	14.4
5-10 kW	0.02	0.1	0.2	1.0	3.1	5.7	10.4	10.5	18.8
10-100 kW	0.1	0.2	0.3	0.6	2.9	7.3	12.4	14.3	19.0
100-500 kW	-	0.1	0.1	0.9	1.3	11.4	10.4	20.4	20.3
>500 kW	-	-	-	-	1.7	5.2	5.0	7.4	16.8
Total	*0.2*	*0.8*	*1.0*	*5.6*	*14*	*36*	*47.9*	*61.2*	*89.3*

4-35

Table B-3. Annual Average Installed Cost and Direct Cash Incentives, by PV Incentive Program and System Size

Program Administrator(s) and Program Name	Size Range (kW)		1998	1999	2000	2001	2002	2003
AZ Public Service: Solar Partners Incentive Program	<10 kW	No. Systems	-	-	-	-	4	8
		Avg. Cost	-	-	-	-	8.6	11.4
		Avg. Incentive	-	-	-	-	3.3	3.5
	10-100 kW	No. Systems	-	-	-	-	-	1
		Avg. Cost	-	-	-	-	-	4.7
		Avg. Incentive	-	-	-	-	-	2.2
	>100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
CA Energy Commission: Emerging Renewables Program	<10 kW	No. Systems	34	168	200	1199	2104	2727
		Avg. Cost	11.9	11.2	10.6	10.1	10.1	9.0
		Avg. Incentive	3.2	3.1	3.0	4.1	4.2	3.8
	10-100 kW	No. Systems	5	9	12	33	135	235
		Avg. Cost	11.6	10.8	8.7	9.7	9.6	8.4
		Avg. Incentive	3.2	3.0	2.8	4.2	4.2	3.9
	>100 kW	No. Systems	-	1	1	4	4	2
		Avg. Cost	-	8.8	7.4	6.2	7.6	8.2
		Avg. Incentive	-	3.1	2.6	2.4	3.5	4.0
Pacific Gas & Electric, Southern Calif. Edison, Calif. Center for Sustainable Energy: Self Generation Incentive Program	<10 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
	10-100 kW	No. Systems	-	-	-	-	11	56
		Avg. Cost	-	-	-	-	9.4	8.1
		Avg. Incentive	-	-	-	-	3.9	3.3
	>100 kW	No. Systems	-	-	-	-	6	43
		Avg. Cost	-	-	-	-	7.8	7.4
		Avg. Incentive	-	-	-	-	3.9	2.5
Pacific Gas & Electric, Southern Calif. Edison, Calif. Center for Sustainable Energy: California Solar Initiative	<10 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
	10-100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
	>100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-

4-36

Program Administrator(s) and Program Name	Size Range (kW)		1998	1999	2000	2001	2002	2003
Los Angeles Dept. of Water & Power: Solar Incentive Program	<10 kW	No. Systems	-	3	3	100	223	118
		Avg. Cost	-	10.9	13.5	10.8	10.0	9.2
		Avg. Incentive	-	3.3	3.3	5.8	6.1	5.6
	10-100 kW	No. Systems	-	-	1	1	7	16
		Avg. Cost	-	-	6.3	10.1	9.6	9.2
		Avg. Incentive	-	-	3.4	5.2	6.0	5.9
	>100 kW	No. Systems	-	-	-	2	2	16
		Avg. Cost	-	-	-	8.3	9.2	9.2
		Avg. Incentive	-	-	-	5.7	6.2	6.0
CT Clean Energy Fund: Solar PV and Onsite Renewable DG Programs	<10 kW	No. Systems	-	-	-	-	-	1
		Avg. Cost	-	-	-	-	-	6.4
		Avg. Incentive	-	-	-	-	-	3.7
	10-100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
	>100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
IL Clean Energy Community Foundation: Renewable Energy Grant Programs	<10 kW	No. Systems	-	-	-	-	2	2
		Avg. Cost	-	-	-	-	19.4	16.3
		Avg. Incentive	-	-	-	-	2.3	2.3
	10-100 kW	No. Systems	-	-	-	-	5	2
		Avg. Cost	-	-	-	-	15.8	16.4
		Avg. Incentive	-	-	-	-	2.0	2.1
	>100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
IL Dept. of Commerce and Economic Opportunity: Renewable Energy Resources Rebate Program	<10 kW	No. Systems	-	9	1	1	-	-
		Avg. Cost	-	19.4	22.7	15.6	-	-
		Avg. Incentive	-	9.1	9.9	7.2	-	-
	10-100 kW	No. Systems	-	-	1	4	5	-
		Avg. Cost	-	-	18.6	11.9	14.4	-
		Avg. Incentive	-	-	7.3	6.6	7.4	-
	>100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-

4-37

Program Administrator(s) and Program Name	Size Range (kW)		1998	1999	2000	2001	2002	2003
MA Technology Collaborative: Small Renewables Initiative	<10 kW	No. Systems	-	-	-	-	-	64
		Avg. Cost	-	-	-	-	-	10.2
		Avg. Incentive	-	-	-	-	-	4.7
	10-100 kW	No. Systems	-	-	-	-	1	5
		Avg. Cost	-	-	-	-	16.4	12.6
		Avg. Incentive	-	-	-	-	13.6	9.3
	>100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
MD Energy Administration: Solar Energy Grant Program	<10 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
	10-100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
	>100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
MN State Energy Office: Solar Electric Rebate Program	<10 kW	No. Systems	-	-	-	-	1	9
		Avg. Cost	-	-	-	-	5.8	9.5
		Avg. Incentive	-	-	-	-	2.3	2.2
	10-100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
	>100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
NJ Clean Energy Program: Customer Onsite Renewable Energy Program	<10 kW	No. Systems	-	-	-	-	-	34
		Avg. Cost	-	-	-	-	-	9.3
		Avg. Incentive	-	-	-	-	-	6.1
	10-100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
	>100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-

4-38

Program Administrator(s) and Program Name	Size Range (kW)		1998	1999	2000	2001	2002	2003
NY State Energy Research and Development Authority: PV Incentive Program	<10 kW	No. Systems	-	-	-	-	-	37
		Avg. Cost	-	-	-	-	-	9.2
		Avg. Incentive	-	-	-	-	-	4.6
	10-100 kW	No. Systems	-	-	-	-	-	6
		Avg. Cost	-	-	-	-	-	9.2
		Avg. Incentive	-	-	-	-	-	5.4
	>100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
Energy Trust of Oregon: Solar Electric Program	<10 kW	No. Systems	-	-	-	-	-	54
		Avg. Cost	-	-	-	-	-	7.8
		Avg. Incentive	-	-	-	-	-	4.5
	10-100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
	>100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
PA Sustainable Development Fund: Solar PV Grant Program	<10 kW	No. Systems	-	-	-	-	3	17
		Avg. Cost	-	-	-	-	12.1	8.9
		Avg. Incentive	-	-	-	-	4.6	4.4
	10-100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
	>100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
WI Focus on Energy: Cash Back Rewards Program	<10 kW	No. Systems	-	-	-	-	10	18
		Avg. Cost	-	-	-	-	10.7	10.5
		Avg. Incentive	-	-	-	-	3.2	2.6
	10-100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-
	>100 kW	No. Systems	-	-	-	-	-	-
		Avg. Cost	-	-	-	-	-	-
		Avg. Incentive	-	-	-	-	-	-

4-39

Appendix C: Calculating After-Tax Cash Incentives and State and Federal Investment Tax Credits

Section 4 presents trends related to combined after-tax financial incentives (direct cash incentives from state/utility PV incentive programs plus state and Federal ITCs) and net installed costs after receipt of these incentives. Calculating this value required that several operations first be performed on the data provided by PV program administrators, as described below.

1. **Segmenting Systems as Residential, Commercial, or Tax-Exempt.** Data provided by many of the programs did not explicitly identify whether the PV systems were owned by residential, commercial, or tax-exempt entities. Unless otherwise identified, we classified all systems <10 kW as residential and all systems >10 kW as commercial.

2. **Estimating the After-Tax Value of Cash Incentives from State/Utility Incentive Programs.** Although the IRS has provided only limited guidance on the issue, it appears that, in most cases, cash incentives provided for commercial PV systems are considered Federally-taxable income. As such, the cash incentives provided for systems in the dataset identified as commercial PV were assumed to be taxed at a Federal corporate tax rate of 35%. The taxation of cash incentives for commercial PV at the state level may vary by state; for simplicity, we assume that all commercial PV systems are taxed at the "effective" state corporate tax rate, which accounts for the fact that state corporate taxes reduce the incentive-recipient's Federally-taxable income. The effective state corporate tax rate applied to the cash incentive is equal to 65% (i.e., 1 minus 35%) of the nominal state corporate tax rate in 2007, which ranged from 6.60% to 9.99% among the 12 states in our dataset.[37]

   Cash incentives paid to residential PV system owners are exempt from Federal income taxes if the incentive is considered to be a "utility energy conservation subsidy," per Section 136 of the Internal Revenue Code. Despite several IRS private letter rulings of potential relevance, uncertainty remains as to what exactly constitutes a "utility energy conservation subsidy." Notwithstanding this uncertainty, we assume that cash incentives provided to all systems in the dataset identified as residential PV are exempt from Federal income taxes. The taxation of cash incentives for residential PV at the state level may vary by state, but for simplicity, we assume that all residential PV systems are also exempt from state income tax.

3. **Estimating the Value of State ITCs.** We identified 5 of the 12 states in our dataset as having offered a state ITC for PV at some point from 1998-2007. Based on the information contained in Table C-1, we determined whether each project in the dataset was eligible for a state ITC, and if so, estimated the amount of the tax credit. In all cases, we assumed that the size of the state ITC was not impacted by any Federal ITC received. We did, however, account for the fact that state tax credits are financially equivalent to Federally-taxable income (since they increase the recipient's Federally-taxable income by an amount equal to the size of the state tax credit). The net value of state ITCs was therefore reduced by 35% to reflect the offsetting increase in Federal income taxes.
4. **Estimating the Value of Federal ITCs.** Projects in the dataset identified as residential PV and installed on or after January 1, 2006 were assumed to receive a Federal ITC equal to the lesser of 30% of the tax credit basis or $2,000. Projects in the dataset identified as commercial PV are assumed to receive a Federal ITC equal to 10% of the tax credit basis if installed prior to January 1, 2006, or 30% of the tax credit basis if installed after that date.

[37] http://www.taxadmin.org/fta/rate/corp_inc.html

4-40

The tax credit basis on which the Federal ITC is calculated depends on whether cash incentives received by a project are Federally-taxable. If the cash incentives are Federally-taxable, as assumed for all commercial PV, then the Federal ITC is calculated based on the full installed cost of the system. If, on the other hand, the cash incentives are not Federally-taxable, as assumed for all residential PV, then the Federal ITC is calculated based on the installed cost minus the value of the tax-exempt cash incentives.

Table C-1: State ITC Details

State	Applicable Customers	System Size Cap	Applicable Period	Tax Credit Amount	Cap
AZ	Residential	None	1995-indefinite	25% of *pre-rebate* installed cost	$1,000
	Non-Residential and Tax-Exempt	None	2006-2012	10% of *pre-rebate* installed cost	$25,000
CA	All	200 kW	2001-2003	15% of *post-rebate* installed cost	None
	All	200 kW	2004-2005	7.5% of *post-rebate* installed cost	None
MA	Residential	None	1979-indefinite	15% of *pre-rebate* installed cost	$1,000
NY	Residential	10 kW	1998-9/1/2006	25% of *post-rebate* installed cost	$3,750
	Residential	10 kW	9/1/2006-indefinite	25% of *post-rebate* installed cost	$5,000
OR	Residential	None	11/4/2005-indefinite	$3/W based on rated capacity (DC-STC)*	$6,000 up to 50% of pre-rebate installed cost
	Non-Residential and Tax-Exempt	None	1981-2006	35% of *pre-rebate* installed cost	$10,000,000
	Non-Residential and Tax-Exempt	None	2007-2017	50% of *pre-rebate* installed cost (up to max. eligible cost**)	$10,000,000

* Tax credit paid out over multiple years, with an annual limit of $1,500/yr.

** Max. eligible cost varies by system size: currently $9/W for systems up to 100 kW, ramping down linearly to $7.50/W for systems >1,000 kW. The tax credit is paid out over five years.

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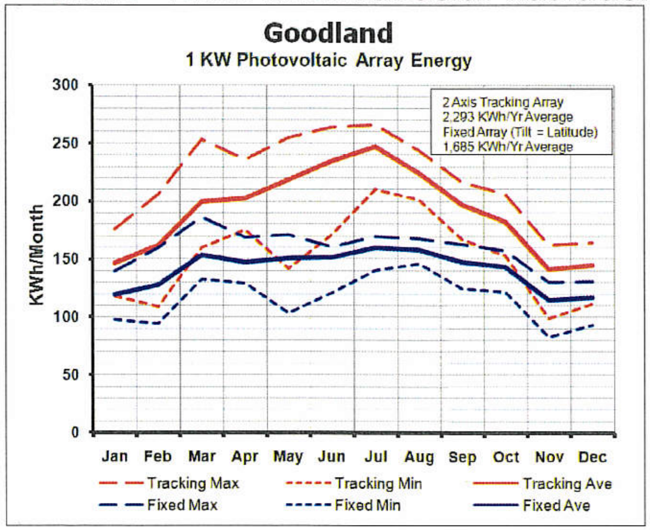
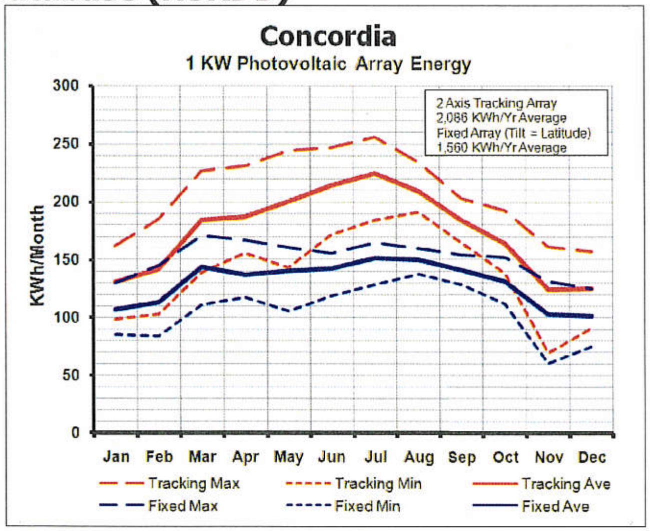
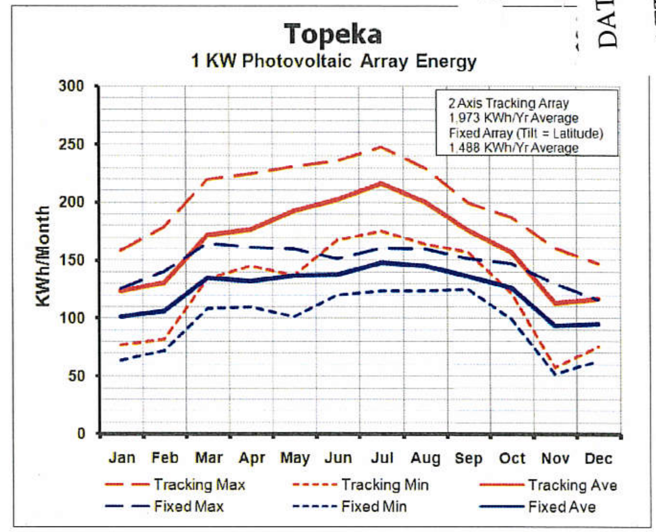
DATE: 3/3/2009
ATTACHMENT 5

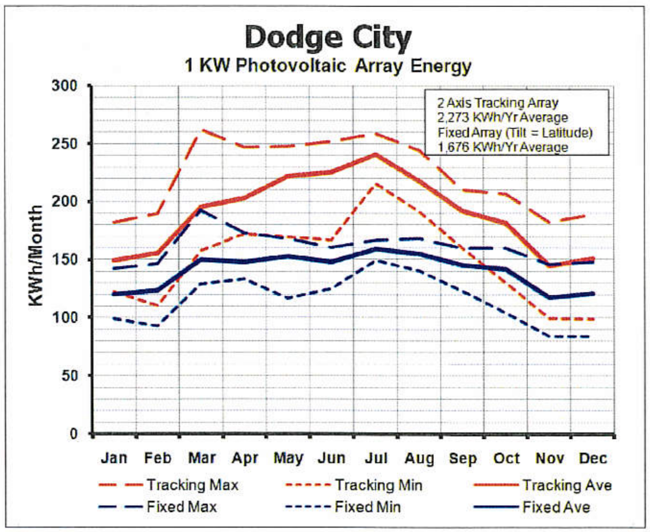
Photovoltaic Electrical Energy Production in Kansas

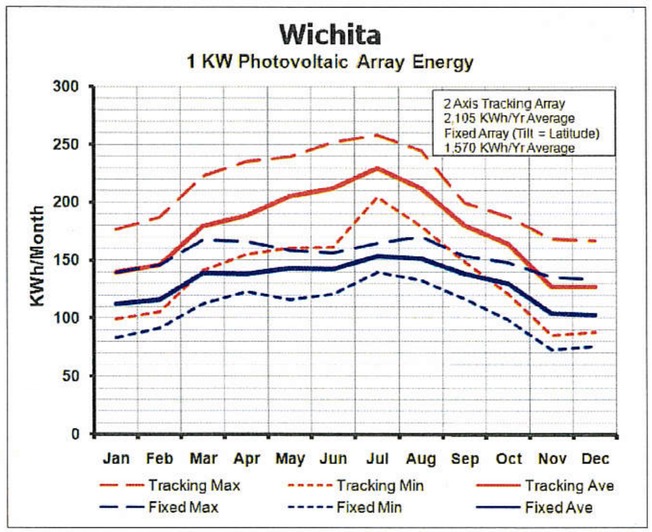
1991 - 2005 National Solar Radiation Database (NSRDB)

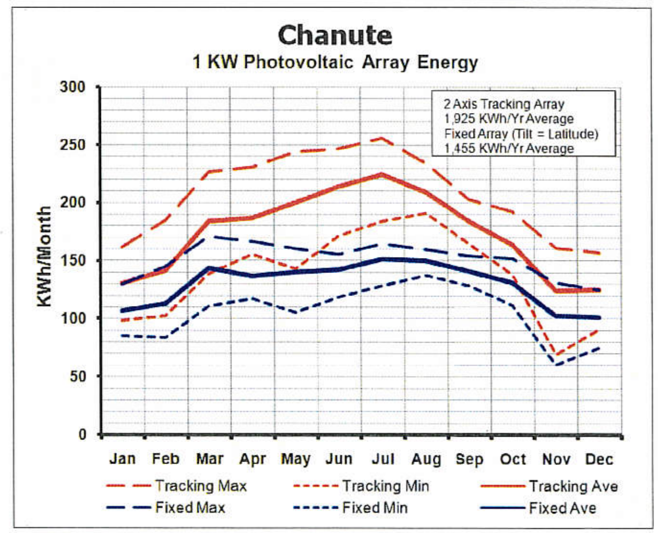












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Kansas Corporation Commission
Energy Programs

Photovoltaic (PV) production of electricity is one way to produce high value renewable energy from sunlight (solar insolation). The graphs above show the estimated monthly electricity production from a one kilowatt (KW) PV system for six representative Kansas communities. The analysis was based on 15 years (1991-2005) of hourly solar insolation data contained in the National Solar Radiation Data Base (NSRB) acquired through the National Renewable Energy Laboratory at http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/. The analysis was based on a commonly available PV panels using PV-DesignPro software available from Maui Solar Energy Software Corporation at http://www.mauisolarsoftware.com/. Inverter losses for converting DC to AC current are included. Other system losses were assumed to be minimal. Maximum, minimum, and long term average values are shown for two panel mounting conditions, one fixed at a tilt equal to the latitude of the site, the second on a two axis tracker that keeps the panels perpendicular to the sun.

Net Metering and Interconnection of Solar Energy Facilities

Jason B. Keyes
Keyes & Fox, LLP

Kansas Solar Round Table
Topeka, Kansas
March 3, 2009

6-2

What IREC Does

- Participate in state utility commission dockets on net metering and interconnection procedures
  - Active in 18 states in the past year
  - Keyes & Fox, LLP for legal support
- Track existing state and local procedures at www.dsireusa.org
- Prepare model procedures and an interconnection guide, *Connecting to the Grid* (both available at www.irecusa.org)
- Assist with development and grading of state procedures in *Freeing the Grid* (available at www.newenergychoices.org)
- Assist with development of procedures in Solar America Cities
- Prepared "Solar ABCs" reports in 2008 on leading interconnection procedures and on the utility external disconnect switch (available at www.solarabcs.org/interconnection and /utilitydisconnect)
- Preparing reports in 2009 on valuation and evolution of net metering
- Primarily funded by the U.S. Dept. of Energy, so no legislative work and no advocacy regarding incentive programs, portfolio standards or subsidies

What IREC Does Not Do

- Renewable Portfolio Standard design
- Incentive program design to pay customers:
  - per Watt upon installation, or
  - per kWh for solar energy generated
- Renewable Energy Credit market design
- Evaluation of traditional generation
- Advocacy regarding renewable energy

Net Metering

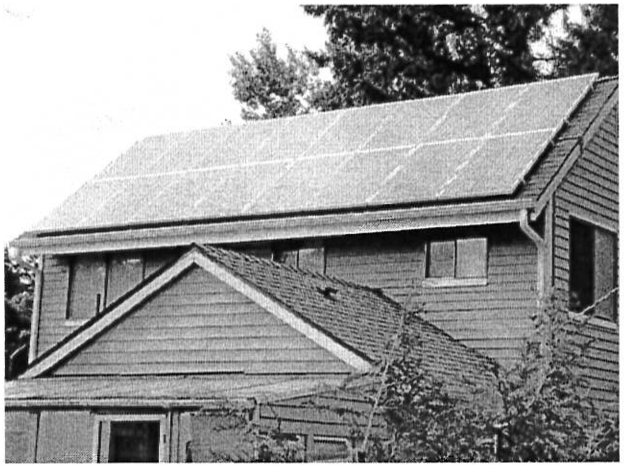
Net Metering Defined

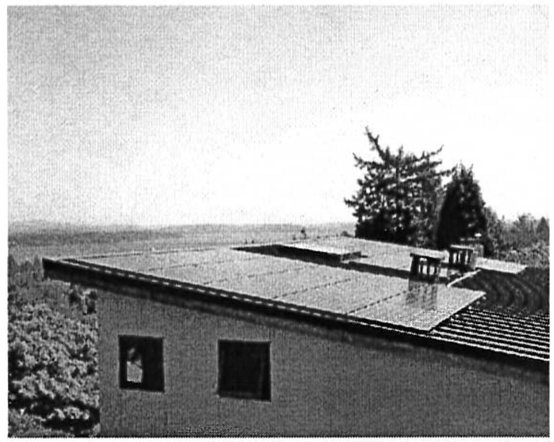
- The Energy Policy Act of 2005 required state utility commissions and larger public utilities to consider adopting net metering, defined as "service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period." 16 U.S.C. 2621(d)(11).
- Put simply, net metering lets a utility customer offset part or all of the customer's load at any given time and get a credit for any excess kWh sent to the utility.
- States legislatures, utility commissions and utilities continue to come up with alternative or more detailed definitions based on facility size, program size, type, rollover period, charges, etc.

How Net Metering Works

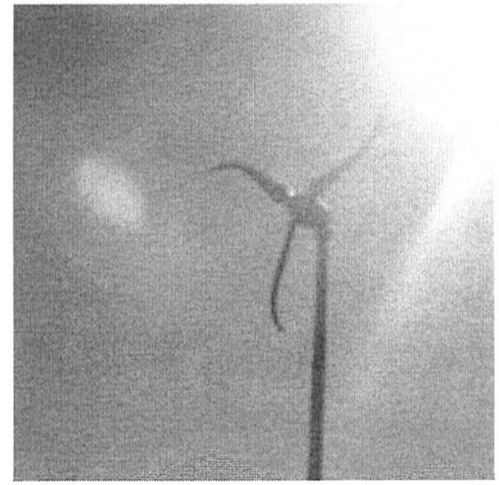
- Always a connection on the customer's side of the meter
- Always restricted to eligible "green" technologies
- Almost always, Renewable Energy Credits stay with the customer
- System sized to meet part or all of customer's consumption over the month (or year), but not more, with minimal or no payment for excess generation
- For solar facilities, electricity is exported to the utility during the daytime, when it is generally more valuable, in exchange for electricity at night, when it is generally less valuable
- Exports example: noon to 1:00 pm, customer generates 5 kWh, uses 3 kWh on-site, exports 2 kWh to utility
- Imports example: 9:00 to 10:00 pm, customer generates nothing, uses 2 kWh on-site, imports 2 kWh
- If there are never any exports, there's no need to net meter. In that case, generation is just offsetting consumption, like conservation.

What It Looks Like

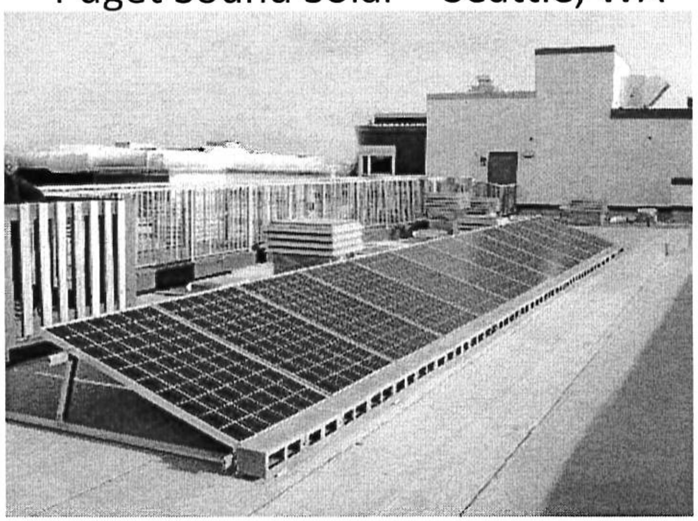




Puget Sound Solar – Seattle, WA



Southwest Windpower's Skystream (2.4 kW peak)

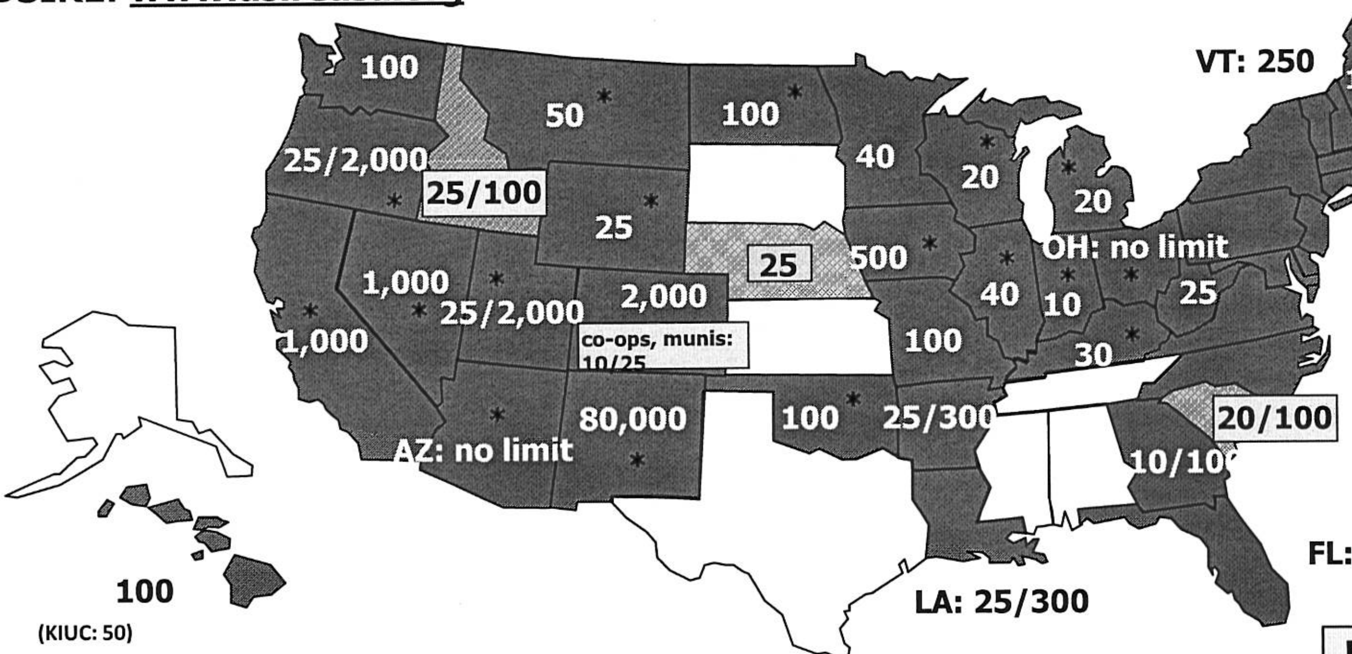


El Solutions, CA, 233 kW

8-9

Where Net Metering Is Offered (facility size limits in kilowatts)

DSIRE: www.dsireusa.org **February 2009**



- State-wide net metering for all utility types
- State-wide net metering for certain utility types only (e.g., investor-owned utilities)
- Net metering offered voluntarily by one or more individual utilities

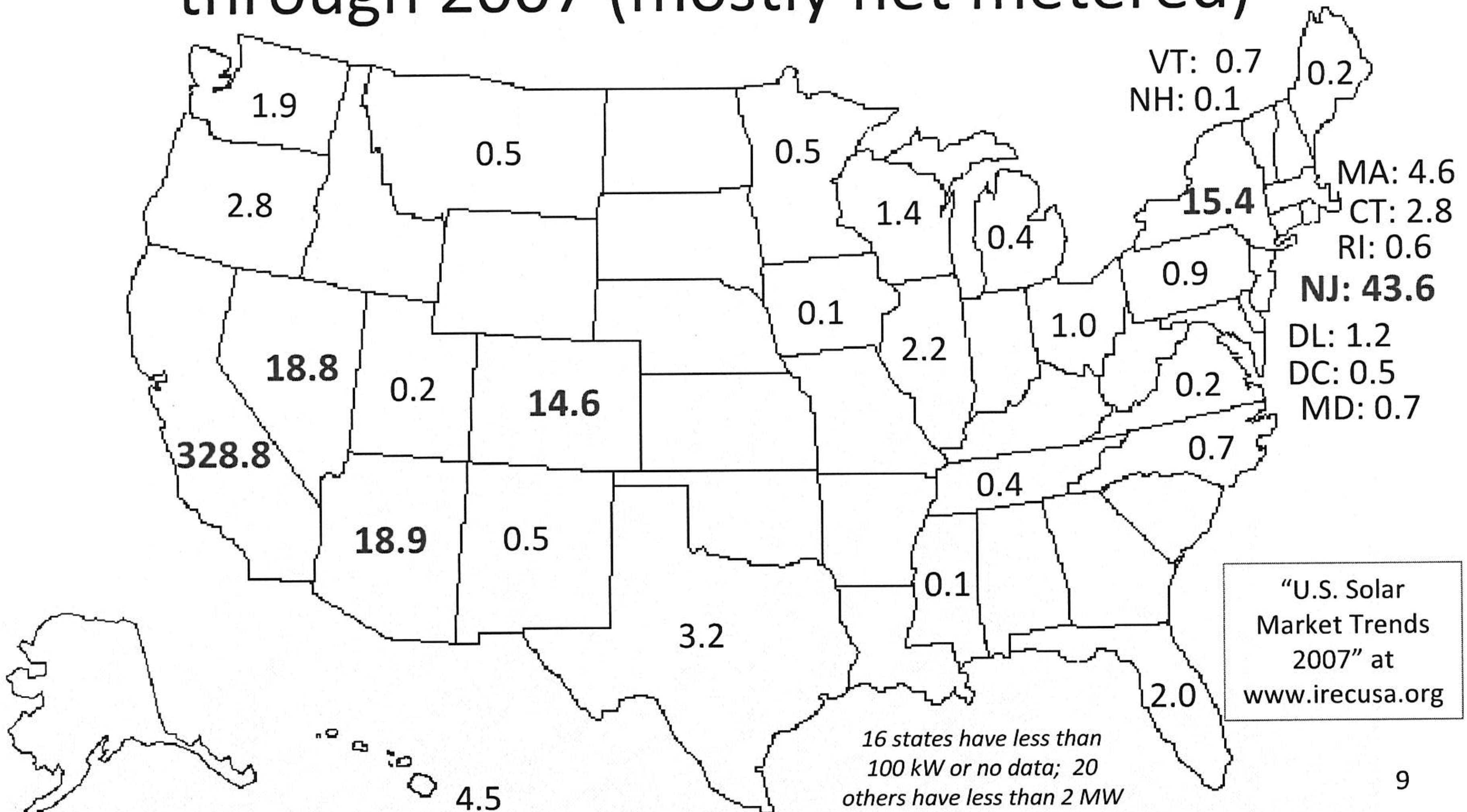
Net metering is available in 43 states + D.C.

Note: Numbers indicate individual system size limit in kilowatts (kW). Some states' limits vary by customer type, technology and/or system application; this is the case when multiple numbers appear for one state. Other limits may also apply. For complete details, see www.dsireusa.org.

IREC INTERSTATE RENEWABLE ENERGY COUNCIL

6-9

475 MW of Grid-Connected Solar PV through 2007 (mostly net metered)



"U.S. Solar Market Trends 2007" at www.irecusa.org

16 states have less than 100 kW or no data; 20 others have less than 2 MW

6-10

The Major Issues

- Caps on facility size
  - 26 states cap at 100 kW or less
  - Where cap is higher, three quarters of capacity is non-residential
- Caps on aggregate enrollment
  - 24 states cap at 1% of utility peak load or less
  - Not an immediate issue outside of California, but important
- Monthly or standby charges
  - Only 11 states have "safe harbor" prohibition of charges
  - A few have standby or monthly charges that erase a facility's value
- Third party ownership limitation
  - Nearly half of capacity in California owned by third parties
  - In states that restrict third party ownership, market potential is halved
- Insurance Requirements
  - Generally in interconnection rules, but can appear in net metering rule
  - Special insurance generally not available for small facilities

Other Important Issues

- Metering
  - Only need one meter that spins both ways
  - Extra meter for production or exports adds cost
  - Even if utility pays, extra meters add to program cost for installation and monitoring, jeopardizing the program's future
- Rollover of excess generation
  - Roll excess kWh to next month to net over seasons and vacations
  - Almost all commercial facilities are not sized to offset all load, and most residential facilities aren't either, so rollover is not logically an issue for most people
  - However, there seems to be a growing interest in completely offsetting load, but people will undersize if they see the possibility of selling power at low rates to their utility
- Valuation of excess generation
  - At end of year, some states allow "avoided cost" payment for excess generation, but customers would prefer payment at their retail rate
  - Utilities resist retail rate payment based on federal avoided cost cap for "QF" purchases
  - States without rollover generally provide for avoided cost payment at month-end
- Community Solar
  - Lots of interest in facilities owned by multiple parties, but hard to structure

Interconnection Procedures

6-13

Interconnection Procedures

- The hot issues of the past year
  - system size limitations (1MW, 10MW, 20 MW, or unlimited)
  - insurance requirements
  - interconnection to spot and area networks
  - starting point for development of procedures
  - utility external disconnect switch
- Other important issues
  - timelines and certainty
  - cost – application fees, studies, certainty
  - technical screens
  - standard form agreements
  - dispute resolution procedures

6-19

System Size Limitations

- Jurisdictional issue – want to avoid system size caps that result in no applicable procedures for a given size
- FERC procedures apply to most transmission line interconnections and certain smaller interconnections
- Many state and local procedures capped at system sizes below one MW, though interconnection of larger systems feasible under state jurisdiction
  - up to 10 MW feasible to higher voltage distribution lines
  - larger systems offsetting demand and not exporting may be feasible
  - a "Qualifying Facility" (up to 80 MW) selling exclusively to utility to which it is interconnecting can typically use state procedures, though interconnecting to FERC-jurisdictional line
- IREC procedures capped at 10 MW, though best approach is to have uncapped state procedures

6-15

Insurance Requirements

- No known insurance claims for utility damages with over 50,000 solar installations in the U.S.
- Homeowner's insurance covers typical net metered systems
- Special insurance not readily or affordably available for residential systems
- Difficult to arrange for larger systems, though feasible for project developers
- Many states do not allow insurance requirement at all
- Potential for utility damages minute for small systems (NM and IL require insurance only for large systems)
- Naming of utility as an "additional insured" is an unnecessary hurdle and impractical for homeowners

Spot and Area Network Interconnection

- Networks are typically supplied from multiple dedicated primary feeders and designed to prevent simultaneous feeder outages so that loads on networks can still be served even when a particular feeder is inoperative
- Networks provide high reliability and are used in many central business districts (area networks) and in some specialized applications such as corporate campuses, malls, etc. (spot networks)
- Flows from distributed generation through network protectors may cause problems
- Non-exporting systems are potential solution
- About 3% of U.S. load is on networks, but they are great potential users of distributed generation
- Under review in IEEE 1547.6, New York City, Solar Cities

6-17

Starting Point for Development of Interconnection Procedures

- Report funded by Solar America Board for Codes and Standards (available by mid-Oct. at www.solarabcs.org)
- Compares leading distributed generation interconnection procedures used as models by state regulators:
  - FERC's Small Generator Interconnection Procedures
  - California's Rule 21
  - MADRI's Model Small Generator Interconnection Procedures (Mid-Atlantic Demand Resource Initiative - PJM Interconnection, PJM state utility commissions and federal agencies)
  - IREC Model Interconnection Standards

Utility External Disconnect Switch

6-17

Utility External Disconnect Switch

- Function of stopping flow to the electric grid when the grid is down is already provided by inverters
- Disconnect switch not required by IEEE 1547
- Duplicative of National Electric Code requirements
- In practice, the switch is not used for emergency and maintenance switching
- States removing the requirement, especially for smaller systems (NY just banned requirement for < 25 kW)
- If required, utilities should have procedures to assure consistent use of the switches

6-20

Interconnection Timelines and Certainty

- Time for notice of application receipt
  - FERC rules say three days
  - best practice is to allow online/instant notice
- Time for notice of complete application
  - FERC rules say ten days from receipt
  - best practice is less time or automated
- Time for review of application
  - FERC rules say 15 days for up to 2 MW systems
  - shorter period feasible for small systems
- Witness test
  - FERC rules say five day notice, which is reasonable
- Study processes – typically no timelines, but some outer bound would be helpful

6-21

Interconnection Costs:
Application Fees, Study Fees and Certainty

- Application fees for 10 kW systems or less
  - FERC uses $100 fee, higher than most states
  - Processing costs eat most of fee, so several states have no fee
  - No casual filers to deter with nominal fee
- Application fees for 10 kW to 2 MW systems
  - FERC uses a flat $500 fee
  - Many states use a sliding scale such as $50 + $1/kW
- Study fees for complicated or larger systems
  - Often open-ended at customer cost (deters applicants)
  - Caps would add certainty; could use sliding scale
  - IREC uses maximum engineering rate
- California has no costs for most net metered systems

6-22

Interconnection Technical Screens

- FERC screens widely adopted – need review given familiarity with solar since 2005
- 15% of line section peak load is first and most significant screen
  - needs exemption for non-exporting systems
  - could use higher percentage for solar systems
  - Need study of grid impacts if line section load is exceeded by generation
- Need short list of screens for small systems

6-23

Standard Form Agreements for Interconnection

- FERC and successful state procedures have standard form agreements
- Without standard form agreements, utilities have little incentive to negotiate and attorneys may be necessary to assure state procedures are followed and customer is being treated fairly
- Some provisions carry through from procedures, but others may only be in agreements, such as indemnity, rights of access, notification, assignment and dispute resolution
- Want to avoid potential for utilities to add provisions not found in state procedures

6-29

Dispute Resolution Procedures

- Potential disputes often relate to small technical matters; fast and inexpensive resolution of such matters worth the risk of error
- Good faith discussions between parties are useful if timeline is short
- Technical master assigned by state utility commission can be used for minor technical disputes
- Utility commission procedures may be functional, but often involve weeks or months of delay
- Non-binding processes add potential for delay and significant cost, and still may wind up in court; want binding arbitration with cap on maximum legal fees that can be awarded

6-25

Questions?

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