Solar PV Deployment in Nebraska: Opportunities & Barriers

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Purpose

Under a technical assistance request made by the Nebraska State Energy Office through the Solar Technical Assistance Team (STAT) program, the National Renewable Energy Laboratory (NREL) provides this technical report for the three largest public power districts in Nebraska—Nebraska Public Power District (NPPD), Lincoln Electric System (LES), and Omaha Public Power District (OPPD). This paper describes the policy, regulatory, technical, and economic issues associated with Nebraska's public power utilities advancing solar PV projects, with the primary audience being key decision-makers at the major public power districts. After initial review and discussion among the primary audience members, key findings and recommendations may be shared with regulators, policymakers and other key stakeholders.

The structure and contents of the technical report was determined during several conference calls between NREL staff and representatives of the Nebraska public power districts. The general outline is as follows:

1. Status of the solar PV market in the U.S. for public utilities
2. Drivers of solar PV markets in the U.S.
3. Competiveness of solar PV
4. Review of public power district interconnection processes and procedures
5. Impact of Homeowners' Association on the deployment of solar PV projects
6. Opportunities for solar gardens (community solar projects) in Nebraska
7. Opportunities for the integration of solar PV into center pivot irrigation systems

Nebraska is the only entirely public power state in the U.S., meaning that the all of the utilities that operate in the state are publicly owned utilities – municipal utilities, electric cooperatives, and public power districts. Nebraska's public utilities are not regulated by a public utilities commission, as investor owned utilities are in other states. Instead, publicly-elected boards and city council representatives control the state's utilities. This does not mean that Nebraska utilities are without state oversight. Ultimately, the state legislature directs the state's utilities through state statues, while Nebraska Power Review Board approves construction of new generation and transmission lines guides the state's long-range power plan. However, neither the Nebraska state legislature nor the Nebraska Power Review Board has mandated that the state's public power utilities integrate distributed generation or renewable energy into their generation mix. This regulatory regime has left the state's utilities with considerable discretion as to how to proceed in integrating solar PV projects. This report will focus on the prospects for growth in Nebraska's distributed generation solar PV market, given the uniqueness of the state's public power utility framework.

Key points from the report

This report touches on a range of issues concerning solar PV and public utilities in Nebraska. Key points from the report include the following:

- Solar PV has seen considerable growth since 2010 and analysts expect this rapid rate growth to continue until the end of 2016.

- Key drivers of solar PV markets in the U.S. are federal tax benefits, solar friendly state policies, utility incentives, and solar capital cost reductions. In recent years, the dramatic drop in solar capital costs has spurred the dramatic increase in solar PV installations.

- The investment tax credit (ITC), a key federal tax benefit, is expected to step down from 30% to 10% at the beginning of 2017. This step down is expected to have a disruptive impact on solar PV markets across the U.S.

- Industry analysts indicate that distributed generation solar PV will be at least at parity with utility electricity rates in 47 states by 2016, including Nebraska. Lower capital costs, lower cost financing, and solar leasing business models will continue to drive the cost of solar downward. However, the step down in the ITC will impact the competitiveness of solar in many states with less competitive solar markets (including Nebraska), likely making solar PV more expensive than the expected future electricity rates.

- The third-party owned solar leasing business model has become a dominant part of the most competitive solar markets (such as California, Arizona, and Colorado).

- The interconnection processes and procedures for the three main public power districts in Nebraska are currently structured for processing a limited number of distributed generation applications. If these utilities expect an increase in distributed solar PV systems in their territories, they should examine the best practices from the major solar PV utilities.

- Net metering policies are currently being debated and reconsidered in several states with large numbers of solar PV installations.

- Many states have passed solar rights laws that place limits on the ability of homeowner associations to restrict the installation of solar PV systems. Nebraska does not have a state wide solar rights law, which likely generates significant uncertainty for prospective purchasers of residential solar PV systems.

- Many other public utilities have implemented community solar programs. These programs vary considerably, but most appear to function much like a green power program.

- The integration of a solar PV system into a center pivot irrigation system has not been a common practice.

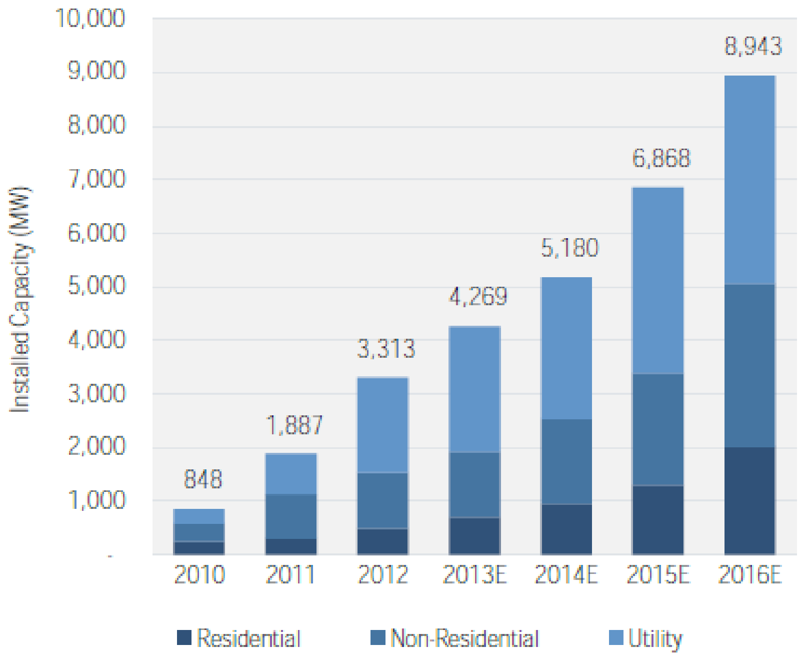
1 Status of solar PV market in the U.S. for public utilities

This section provides an overview of the U.S. solar PV market, including installations, geographic distribution, and leading utilities in deployment.

1.1 Past and forecasted solar PV installation trends in the U.S.

As illustrated in Figure 1, the capacity of solar PV installations in the U.S. has seen significant growth since 2010, driven by significant capital cost reductions and other market and policy drivers that will be discussed in proceeding sections. In 2012, 3.3 GW of solar PV installations were installed, representing a 76 percent increase over the capacity installed in 2011.[1]

Figure 1: U.S. solar PV Installation Forecast, 2011-2017[2]



[1] *U.S. Solar Market Insight Report, 2012 Year in Review*, SEIA and GTM Research

[2] Data sourced from *U.S. Solar Market Insight Report, 2012 Year in Review*, SEI and GTM Research.

Looking ahead, according to Figure 1, the overall annual nameplate capacity of solar PV installations in the U.S. is expected to continue to grow with total installed capacity of solar PV systems projected to nearly triple between 2013 and 2016.[3] In 2017, the federal investment tax credit (ITC) is currently scheduled to drop from the current 30% to 10% for commercial and third-party-owned systems and drops to zero for directly owned residential systems (further detailed in Section 2). Industry analysts expect a dramatic drop in system installations in 2017 due to the stepdown in the ITC.[4] There will be more disussion of the ITC and its impact on solar markets in Section 2.

1.2 Geographic distribution

The states with the most total installed nameplate capacity of solar PV are shown in Table 1. The nameplate capacity installed in these states alone represents 85 percent of the total in the U.S., with California accounting for over a third of the solar PV installed in the U.S. This geographic distribution is largely due to several localized factors, which will be discussed in following sections.

Table 1: States with the largest total nameplate capacity of solar PV installed thru the end of 2012 and by year (MW)[5]

	2008	2009	2010	2011	2012	Total
California	198	212	259	542	1033	2537
Arizona	6	21	54	273	710	1094
New Jersey	23	57	137	313	415	971
Nevada	15	3	61	44	198	339
Colorado	22	23	54	91	40	239
North Carolina	4	8	31	55	132	229
Massachusetts	4	10	22	31	129	198
Pennsylvania	3	3	47	88	54	196
Hawaii	9	13	15	40	109	190
New Mexico	1	1	43	116	24	184

Solar PV installations across the U.S can be grouped into three general market segments — residential, commercial, and utility, with residential and commercial market segments representing distributed generation. Table 2 provides the allocation of total nameplate capacity by segment in the top ten states with the largest nameplate capacity of solar PV installed through the end of 2012. As Table 2 illustrates, the dominant market segment differs from state to state. For example, Arizona's utility scale projects represent 70% of the total installed nameplate

[3] Other industry analysts consider these numbers to overly optimistic. Bloomberg New Energy Finance projects considers an optimistic U.S. PV demand forecast for 2015 to be 5,200 MW, compared to the 6,868 MW shown in Figure 1.

[4] U.S. Solar Market Insight Report, Q1 2013 Full Report, SEIA and GTM Research, 2013.

[5] Data sourced from *U.S. Solar Market Insight Report, 2010 Year-In-Review*, SEIA and GTM Research; *U.S. Solar Market Insight Report, 2011 Year-In-Review*, SEIA and GTM Research; *U.S. Solar Market Insight Report, 2012 Year in Review*, SEIA and GTM Research; EIA Detailed State Data, Existing Nameplate and Net Summer Capacity By Energy Source, Producer Type and State 1990-2011, http://www.eia.gov/electricity/data/state/.

capacity in the state, while Hawaii's utility scale projects only represent 10% of the total installed nameplate capacity in the state. State renewable energy policies largely drive these differences.

Table 2: States with the largest nameplate capacity of solar PV installed through the end of 2012, by market sector (MW)[6]

	Residential	Commercial	Utility	Total
California	674	1051	813	2537
Arizona	149	174	771	1094
New Jersey	125	692	156	971
Nevada	7	37	295	339
Colorado	66	101	72	239
North Carolina	7	40	182	229
Massachusetts	29	149	19	197
Pennsylvania	40	135	22	196
Hawaii	95	79	16	190
New Mexico	13	15	157	184

1.3 Leading public power utilities

The public power utilities with the most installed solar PV nameplate capacity are shown in Table 3. There are many state- and utility-specific factors that play into why these utilities have embraced solar PV installations, which will be further discussed in the next section.

Table 3: Public-owned utilities with the most installed solar PV nameplate capacity in 2011.[7]

Utility	State	Total installed capacity (MW-AC)	Watts per customer installed in 2011
Sacramento Municipal Utility District	California	52.8	88.5
Long Island Power Authority	New York	46.9	42.0
Austin Energy	Texas	29.7	71.4
Vineland Municipal Electric Utility	New Jersey	18.9	768.5
Los Angeles Dept. of Water and Power	California	14.0	N/A
Salt River Project	Arizona	9.2	N/A
Imperial Irrigation District	California	4.9	33.1
Orlando Utilities Commission	Florida	4.9	22.1
Gainesville Regional Utilities	Florida	4.8	52.5
Turlock Irrigation District	California	3.0	29.8

[6] Data sourced from *U.S. Solar Market Insight Report, 2010 Year-In-Review*, SEIA and GTM Research; *U.S. Solar Market Insight Report, 2011 Year-In-Review*, SEIA and GTM Research; *U.S. Solar Market Insight Report, 2012 Year in Review*, SEIA and GTM Research.
[7] Information sourced from Solar Electric Power Association's *2011 SEPA Utility Solar Rankings*, May 2012.

2 Drivers of solar PV markets in the U.S

Solar PV markets are influenced by a number of economic and policy market drivers. This section will provide an overview of these drivers, which include federal tax benefits, state policies, utility incentives, capital cost reductions, and retail electricity prices.

2.1 Federal tax benefits

Federal tax benefits are the major driver of renewable energy project development in the U.S. This section will discuss the two primary federal tax credit provisions that impact solar PV projects, the investment tax credit (ITC) and Modified Accelerated Cost Recovery System (MACRS) – accelerated depreciation. In total, the ITC and MACRS can reduce total solar PV system costs for system owners by 50-60%, and beyond with bonus depreciation.

2.1.1 Investment tax credit / Treasury 1603 grants

Since 2006, owners of qualified solar facilities have been able to claim an investment tax credit (ITC) under Section 48 of the internal revenue code. For solar PV systems, the ITC is a one-time credit of 30 percent of the tax basis of the energy property, serving as the main federal policy mechanism supporting solar installations in the U.S. Applying to solar facilities that are placed in service before January 1, 2017, the ITC will be lowered to 10 percent of the tax basis of the qualifying energy property after January 1, 2017.

Further, as part of the American Recovery and Reinvestment Act (ARRA), Congress enacted a U.S. Treasury Grant in Lieu of Tax Credits Program (1603 Treasury Grant Program) which provided the alternative of a cash grant instead of the tax credit. While the program was closed to new grant applications at the end of 2011, many solar project developers currently have pending applications for projects that qualified for the program under begun construction provisions. Project developers with pending applications have until the end of 2016 to commission their solar PV projects. As of March 2013, over 75,000 solar PV project had received a grant through the 1603 Treasury Grant Program, with solar PV project grants awarded totaling more than $4.3 billion.[8]

2.1.2 MACRS Depreciation

The Modified Accelerated Cost Recovery System (MACRS) is a federal method of depreciation where a solar investment can be recovered for tax purposes through an accelerated five year schedule. MACRS can represent a significant tax incentive to renewable energy project owners, representing a tax benefit of 26% of the total system costs.[9] Further adding to the tax benefits related to MACRS, an additional 50 percent first-year bonus depreciation provision for renewable energy systems was put into place in 2008. This bonus deprecation has been extended several times—most recently in January 2013 under The *American Taxpayer Relief Act of 2012*, which extended the service deadline for projects to qualify for bonus depreciation to December 31, 2013.

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[8] For more information on the 1603 Treasury Grant Program, see program's status overview at http://www.treasury.gov/initiatives/recovery/Documents/STATUS%20OVERVIEW.pdf.

[9] For more information, see Mark Bolinger's 2009 report, *Financing Non-Residential Photovoltaic Projects: Options and Implications*; http://eetd.lbl.gov/EA/EMP/reports/lbnl-1410e.pdf

2.2 State policies, regulations, and incentives

State policies, regulations, and incentives are also critical drivers of solar deployment, and have played a significant role in recent market development. Most prominent of these state policy drivers is the state renewable energy portfolio standard (RPS). RPS policies help encourage investments in solar PV projects by requiring a certain percentage of utility generation to come from various renewable energy sources. Some states create specific RPS carve-out provisions for solar requirements, which can by design increase demand for and installation of distributed solar. Of the 14 states that had more than 10 MW of utility sector installations in 2012, 12 of the states have an RPS. Most also have a solar carve out.[10]

Table 4 includes details of the RPS in states with the largest total nameplate capacity of solar PV installed through the end of 2012.

Table 4: Renewable portfolio requirements for the top ten states with the largest total nameplate capacity of solar PV installed through the end of 2012, with solar carve-out details[11]

	RPS	Solar Carve-Out
California	20% by Dec. 31, 2013 25% by Dec. 31, 2016 33% by 2020	No
Arizona	15% by 2025	Distributed generation carve-out: 30% of annual requirement in 2012 and thereafter (4.5% of sales in 2025)
New Jersey	20.38% Class I and Class II renewables by energy year 2020-2021	4.1% solar by energy year 2027-2028
Nevada	25% by 2025	5% of annual requirement through 2015 (1.2% of total sales) 6% for 2016-2025 (1.5% of total sales)
Colorado	IOUs: 30% by 2020 Electric cooperatives serving fewer than 100,000 meters: 10% by 2020 Electric cooperatives serving 100,000 or more meters: 20% by 2020 Municipal utilities serving more than 40,000 customers: 10% by 2020	Distributed generation minimums
North Carolina	IOUs: 12.5% by 2021 Electric cooperatives, municipal utilities: 10% by 2018	0.2% by 2018
Massachusetts	Class I: 15% by 2020 and an additional 1% each year thereafter Class II: 7.1% in 2009 and thereafter	Mandated target of 400 MW
Pennsylvania	18% by compliance year 2020-2021	0.5% solar PV by compliance year 2020-2021

[10] Interstate Renewable Energy Council, 2013. *U.S. Solar Market Trends 2012.*
[11] Data sourced from the *Database of State Incentives for Renewable Energy & Efficiency*.

Hawaii	40% by 2030	No
New Mexico	IOUs: 20% by 2020 Rural electric cooperatives: 10% by 2020	20% of RPS requirement (4% of sales) for IOUs only (in 2020)

In addition to the RPS, states also have considerable control over interconnection and net metering requirements. Interconnection and net metering policies will be discussed further in Section 4.

2.3 Utility incentives

Financial incentives offered by utilities also have been one of the most important determinants to solar PV growth. The public power utilities with the most installed solar PV are motivated to offer incentives for a variety of reasons. Table 5 provides a basic outline of the policy drivers of utility solar PV programs.

Table 5: Utilities with significant solar PV deployment and their policy drivers

Utility	Policy Driver for PV deployment
Sacramento Municipal Utility District (CA)	State RPS
Long Island Power Authority (NY)	State RPS with PV requirement
Austin Energy (TX)	City RPS with PV requirement
Vineland Municipal Electric Utility (NJ)	State RPS with PV requirement
Los Angeles Dept. of Water and Power (CA)	State RPS
Salt River Project (AZ)	Voluntary RPS set by utility
Imperial Irrigation District (CA)	State RPS
Orlando Utilities Commission (FL)	Voluntary utility program
Gainesville Regional Utilities (FL)	Voluntary utility program
Turlock Irrigation District (CA)	State RPS

As shown in Table 5, several publicly owned utilities in California adhere to the state's RPS requirements. Even though public utilities in California are not regulated by the California Public Utilities Commission, the governing boards of the utilities are expected to establish procurement requirements based on the state's RPS goals.[12] In addition, the Long Island Power Authority (LIPA) is not under the jurisdiction of the state's RPS program, but the utility has chosen to adopt a renewable energy goal that mirrors the state target.

Of the utilities listed in Table 5, several are not located in states with aggressive RPS requirements for publicly owned utilities. Without state level policies, these municipal utilities are directed by city councils to advance the deployment of solar PV installation. For instance, Austin Energy's RPS was included as part of the city's Climate Protection Plan, which was adopted by a city council resolution on 2007.

[12] See DSIRE for more information on the California RPS - http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA25R&ee=0.

Table 6 provides details the solar-specific incentives driving deployment within respective territories of the top public power utilities. The utilities offer a mix of performance-based incentives (PBI) and capacity-based incentives. All of the utilities have adjusted their incentives over the years, likely accounting for the sharp drop in capital costs for solar PV systems.

Table 6: Solar incentives for utilities with significant solar PV deployment

Utility Program budget	**Solar incentives**
Sacramento Municipal Utility District	Residential: $0.25/W-AC Non-Residential: Expected PBI - $0.65/W-AC; PBI - $0.10/kWh for 5 years or $0.06/kWh; $650K max per project.
Long Island Power Authority $28.8 M	Residential (general customer-owned): $1.86/W-AC; $18,600 max Residential (third-party owned): $1.72/W-AC; $18,600 max Residential (non-profit owned): $2.25/W-AC; $22,500 max Commercial: $1.72/W-AC; $172,000 max Gov't, Schools, Nonprofits: $2.25/W-AC; $225,000
Austin Energy Residential: $7.35 M	Residential: $1.50/W-AC; $15,000 max Commercial: “value of solar” tariff - $0.128/kWh: 20kW max size
Vineland Municipal Electric Utility	State RPS initiated Solar Renewable Energy Credit (SREC) market (performance-based incentive); 2012 price ranged from $225-390 per MWh
Los Angeles Dept. of Water and Power $30 M	Residential: $1.05/W-AC; max up to 75% of project costs
Salt River Project	Residential PV: $0.10/W Nonprofit, School, and Government PV: $0.04/kWh Small Commercial PV: $0.10/W
Imperial Irrigation District	Less than 30 kW: $1.95/W Larger than 30 kW: $0.18/kWh over 5 year period
Orlando Utilities Commission	None listed
Gainesville Regional Utilities	Feed-in Tariff.
Turlock Irrigation District	**Systems smaller than 30 kW:** Residential: $1.48 per watt AC Commercial: $0.35 per watt AC; incentives may be adjusted based on expected performance **Systems 30 kW or larger:** Residential: $0.17/kWh Commercial: $0.04/kWh; payments are made monthly for 5 years

2.4 Solar PV capital cost reductions

Solar PV systems have been used for more than 50 years in some applications and for more than 20 years in grid-connected systems. In the past, high costs relative to other generation options often prevented commercial deployment—global cumulative installation was only about 16 GW five years ago when PV technologies faced technical and economic barriers. However, the economics of PV are changing, and the industry has experienced significant reductions in the underlying costs and market prices. Over the past three years, the total installed cost for distributed installations declined 33 percent, and 12 percent in 2012 alone.

Although the cost of all solar PV system components has fallen, the decline in solar PV module costs primarily drove the decline in overall system cost.[13] As an illustration, the price of PV modules remained relatively flat (around $3.50-$4.00/W) from 2004 to Q3 2008. But as the industry became more competitive, prices fell rapidly to roughly $2.00/W in 2009.[14] By late 2011, price of PV modules fell below $1.00/W.

Table 7 provides the average installed capital costs for solar PV systems in the U.S. by market segment in 2011 and 2012, illustrating the significant declines of the last two years.

Table 7: Solar PV installed costs by market segment, 2011-2012[15]

	Q1 2011	Q2 2011	Q3 2011	Q4 2011	Q1 2012	Q2 2012	Q3 2012	Q4 2012
Residential	$6.34	$6.35	$6.15	$6.16	$5.88	$5.45	$5.22	$5.04
Non-Residential	$5.22	$5.09	$4.90	$4.92	$4.65	$4.35	$4.21	$4.27
Utility	$3.85	$3.75	$3.45	$3.20	$2.90	$2.60	$2.40	$2.27
Blended	$5.33	$5.15	$4.41	$4.10	$4.46	$3.47	$3.58	$3.01

According to this data, the average installed price for residential systems was $6.34/W in the first quarter of 2011 and $5.04/W by the end of 2012. SEIA and Greentech Media, the authors of the data in Table 7, highlight that these are simply averages and there are significant differences from state to state and from region to region. In many competitive solar markets, installed costs for residential systems may be much lower than $5.04/W at the end of 2012. Several industry insiders have indicated that many major solar installers are already installing residential systems below $3.75/W, going as far as to say residential systems are being installed in some areas of the U.S. in mid-2013 at $2.50 to $2.75/W.[16]

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[13] Interstate Renewable Energy Council, 2013. *U.S. Solar Market Trends 2012*.

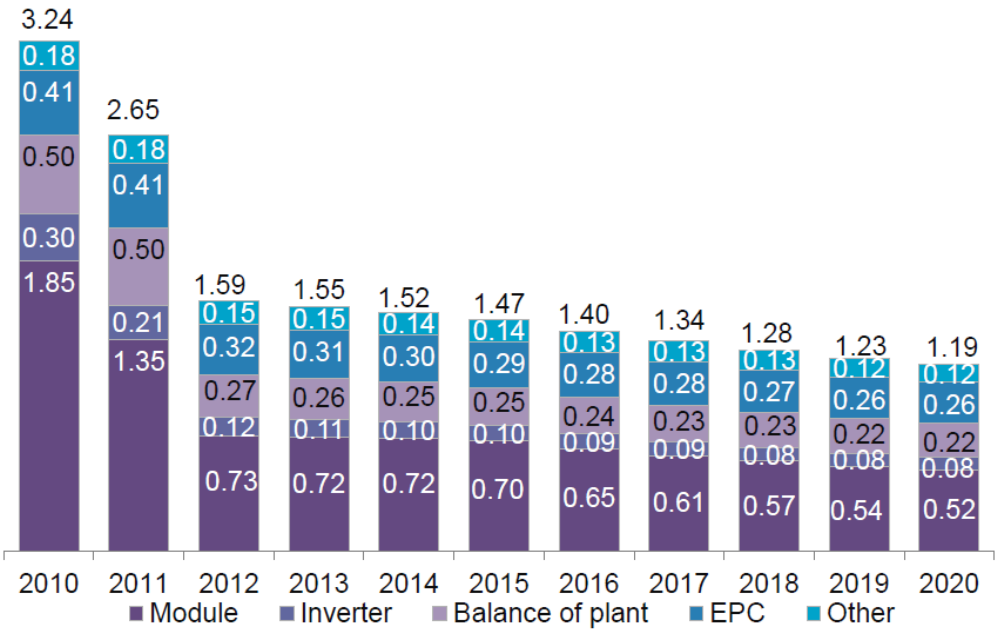
[14] Bazilian, M., Onyeji, I., Liebrich, M., MacGill, I., Chase, J., Shah, J., Gielen, D., Arent, D., Landfear, D., and Zhengrong, S., 2012. Reconsidering the economics of Photovoltaic Power. Bloomberg New Energy Finance. London and New York, 16 May 2012.

[15] *U.S. Solar Market Insight Report, 2012 Year in Review*, SEIA and GTM Research.

[16] In a September 24, 2012 interview with SNL Financial, the Senior Vice President of Clean Power Finance indicated that "best in class" installers are currently installing residential systems at $3.50/W. During an event at the GTM Solar Summit on April 24th, OneRoof Energy CEO indicated that residential systems in Phoenix were being installed at $2.50 to $2.75/W - http://www.ustream.tv/recorded/31902831.

In regards to the system costs for the utility market segment, Table 7 indicates that SEIA and Greentech Media estimate utility scale projects to be installed on average for $2.27/W in the end of 2012, down from $3.85/W at the beginning of 2011. However, according to cost data from Bloomberg New Energy Finance, utility-sized system prices may be considerably lower. Figure 2 shows the forecasted costs for utility-scale, ground-mounted PV projects, as indicated by data from Bloomberg New Energy Finance. The sharp drop in equipment costs (module, inverter, and balance of plant) have pushed installed costs for utility scale PV systems down to $1.55/W in 2013.

Figure 2: Forecast costs for utility-scale, ground-mounted PV projects, 2010-2020 ($/W)[17]



2.5 Utility Rates

Electricity rates also play a crucial role in whether solar PV will see significant adoption in a region. High electricity prices provide an additional financial incentive for consumers to purchase or lease a solar PV system. Table 8 shows the average residential and commercial electricity rates for the states with the most solar PV installed nameplate capacity.

Table 8: Average retail price of electricity for top solar PV states as of June 2013[18]

	State average residential electricity rate	State Average commercial electricity rate
California	$0.16	$0.13
Arizona	$0.11	$0.10

[17] Bloomberg New Energy Finance, U.S. Solar Outlook, March 13, 2013
[18] EIA data.

New Jersey	$0.16	$0.13
Nevada	$0.12	$0.09
Colorado	$0.12	$0.10
North Carolina	$0.11	$0.09
Massachusetts	$0.15	$0.14
Pennsylvania	$0.13	$0.09
Hawaii	$0.37	$0.34
New Mexico	$0.11	$0.09
Nebraska	*$0.10*	*$0.08*

As shown in Table 8, other than Hawaii, states with most installed capacity of solar PV have average residential electricity rates of between $0.11/W and $0.16/W and average commercial rates between $0.09/W and $0.13/W. All of these states have higher average commercial and residential electricity rates than Nebraska, but average rates for several of the states are only marginally higher.

Table 9 shows a comparison of average residential and commercial retail electricity rates of the public power utilities with the most installed capacity of solar PV and the rates of Nebraska's public power utilities. Once again, Nebraska's public power utilities have lower rates, but the rates are not significantly lower than rates offered by Austin Energy or Salt River Project, two utilities that have substantial amounts of solar PV installed.

Table 9: The average retail electricity price (per kWh) for public power utilities with significant solar PV installed capacity, 2011[19]

Utility	Residential Retail Electricity Rate	Commercial Retail Electricity Rate
Sacramento Municipal Utility District (CA)	$0.12	$0.14
Long Island Power Authority (NY)	$0.20	$0.18
Austin Energy (TX)	$0.10	$0.09
Vineland Municipal Electric Utility (NJ)	$0.15	$0.15
Los Angeles Dept. of Water and Power (CA)	$0.13	$0.13
Salt River Project (AZ)	$0.11	$0.09
Imperial Irrigation District (CA)	$0.12	$0.11
Orlando Utilities Commission (FL)	$0.12	$0.10
Gainesville Regional Utilities (FL)	$0.13	$0.14
Turlock Irrigation District (CA)	$0.15	$0.11
Lincoln Electric System	*$0.09*	*$0.07*
Nebraska Public Power District	*$0.11*	*$0.08*
Omaha Public Power District	*$0.09*	*$0.08*

[19] EIA. http://www.eia.gov/electricity/data.cfm#sales

3 Competitiveness of solar PV

3.1 Overview

Even within the same state, installed costs can vary by more than $2.00/W depending on other project-specific factors. There are four drivers of state-level system pricing other than the component costs previously discussed. These include: market maturity, labor costs, "soft" costs, and system size.[20]

The more established and larger a state market is, the more likely it is to attract more experienced developers that can offer lower system prices. Larger systems typically result in lower installed prices per watt. Similarly, states with higher labor costs will typically have higher system costs. Soft costs such as permitting, interconnection, incentive applications, financing, and other fees also vary significantly and contribute to overall project costs. More specifically, if these factors are time-consuming and complex, they will result in more expensive system prices.

3.2 How far to grid parity

A recent markets research report from Deutsche Bank released in September 2013 that examined how close distributed solar PV is to grid parity across the U.S. Deutsche Bank's analysis indicates that solar PV is already at grid parity in 10 states, as shown in Table 10.[21]

Table 10: States currently at grid parity according to Deutsche Bank

Grid Parity at $3.00 ($2.10 w/ ITC)	LCOE ($/KWh)	Average Cost of Electricity ($/KWh)
Arizona	$0.11	$0.11
California	$0.12	$0.16
Connecticut	$0.15	$0.17
Hawaii	$0.12	$0.37
Nevada	$0.10	$0.12
New Hampshire	$0.15	$0.16
New Jersey	$0.15	$0.16
New Mexico	$0.11	$0.11
New York	$0.15	$0.18
Vermont	$0.16	$0.17

In addition, the Deutsche Bank report showed that 11 more states would reach grid parity as system costs continued to decline. These states are shown in Table 11.

Table 11: Additional states expected to reach grid parity in the 18 months according to Deutsche Bank

[20] U.S. Solar Market Insight Report, Q1 2013 Full Report, SEIA and GTM Research, 2013.
[21] *Distributed Generation to Herald New U.S. Growth Era*, Deutsche Bank Markets Report, September 3, 2013.

Grid Parity at $2.50 ($1.75 w/ ITC)	LCOE ($/KWh)	Average Cost of Electricity ($/KWh)
Colorado	$0.10	$0.12
Delaware	$0.12	$0.13
Washington, DC	$0.12	$0.12
Florida	$0.11	$0.11
Kansas	$0.11	$0.11
Maryland	$0.12	$0.13
Massachusetts	$0.13	$0.15
Michigan	$0.14	$0.14
Pennsylvania	$0.13	$0.13
Rhode Island	$0.13	$0.15
South Carolina	$0.11	$0.12
Wisconsin	$0.13	$0.13

Source: Deutsche Bank

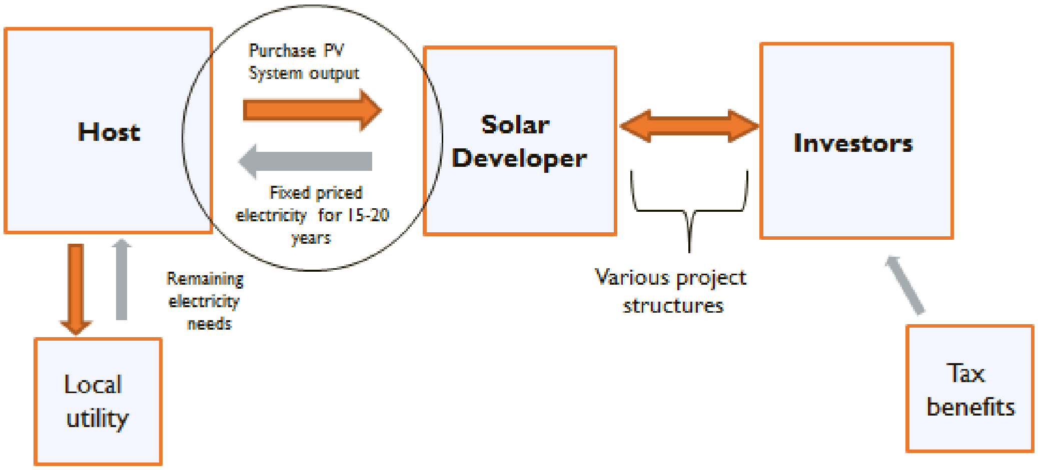
The Deutsche Bank analysts expect the drive to grid parity to be fueled by reduced system costs, new lower cost financing vehicles, and solar leasing business models. The report comments on the importance of the 30% ITC to the cost effectiveness of solar PV systems. In fact, the report anticipates that by the end of 2016, 47 states will reach grid parity – including Nebraska. However, if the ITC steps down to 10% in 2017, a solar PV system in Nebraska would have an LCOE slightly above the state's estimated average future cost of energy.

The analysis does not take into account that solar markets vary considerably across the U.S. For instance, the fact that Nebraska does not have a highly competitive, mature solar PV market indicates that a 50 kW solar PV system would currently be in the $4 to $5 per watt range. Only states with competitive solar markets, such as California and Arizona, have seen distributed solar PV systems installed at or under $3 per watt. With system capital costs in the $4 to $5 per watt range, a solar PV system would likely not be currently competitive with current retail electricity rates in Nebraska.

3.3 Third-party ownership (solar leasing) model discussion

A dominant ownership model in all sectors for distributed installations is third-party ownership, and the structure is typically called a solar power purchase agreement (PPA) or solar lease. In this business model, third parties own the systems while consumers make payments to the owner as the system is located at the consumer's home or facility (for distributed systems) and the electricity is generated onsite. This model allows consumers to avoid paying the large upfront capital requirements of a PV system, as the consumer can experience the benefit of lower energy bills with little to no upfront cost. Figure 3 provides an illustrative example of how third-party ownership works in practice.

Figure 3: Third party ownership model[22]

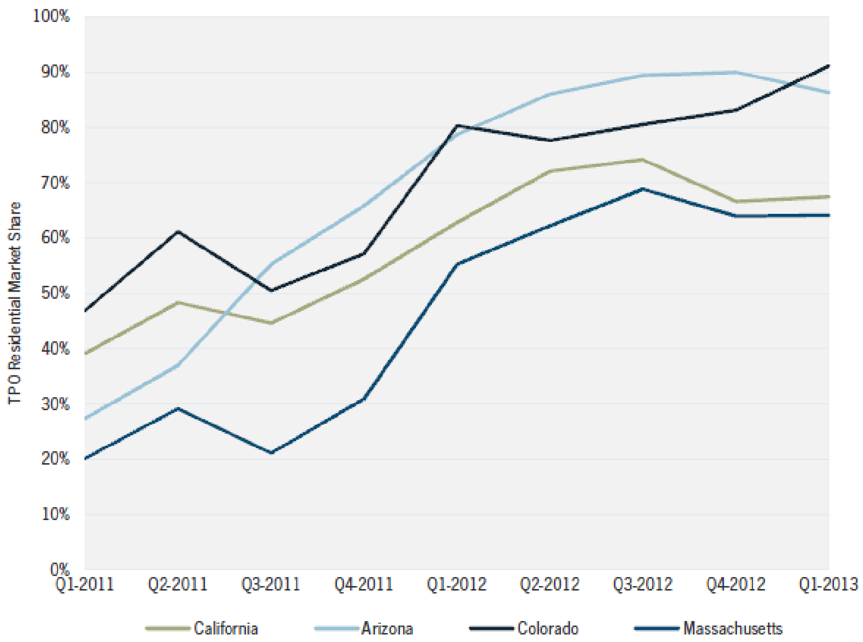


The third-party ownership model allows the third party owner to collect all of the available federal, state, and utility incentives. In general, federal tax benefits are able to be used more effectively by third part owners through complex buisness structures. As a consequence, the third-party owner can offer lower cost lease payments or PPA power prices to customers, compared to what the customer is paying for grid power or what the customer could pay by directly purchasing and owning a solar PV system. In addition to no upfront costs and low power prices, customer benefits from the third party owned system through price certainty for power over the term of the PPA or lease, as well as the third party owner assuming responsibility for O&M.

Thid-party ownership residential PV systems have become an increasingly attractive option for many in states with competitive solar markets. In 2012, solar leases and PPAs continued to gain momentum, increasing to more than 50 percent of all installations in most major residential markets.[23] Figure 4 provides a graph of the percentage of new residential installations owned by third parties in four key markets: California, Arizona, Colorado, and Massachusetts.

Figure 4: Percentage of new residential installations owned by a third party in CA, AZ, CO, and MA, Q1 2011 – Q1 2013[24]

[22] *Solar Finance for Residential and Commercial Customers Potential Roles of State and Local Government*, Solar Technical Assistance Team 2013 Webinar presented by Jason Coughlin, May 1, 2013; http://www1.eere.energy.gov/solar/sunshot/stat2013.html.
[23] SEIA, Q4 2012.
[24] Figure extracted from U.*S. Solar Market Insight Report, Q1 2013 Full Report*, SEIA and GTM Research, 2013.



4 Review of power district interconnection and net metering policies and processes

4.1 Interconnection Process

Interconnection processes specify the legal, technical, and procedural requirements for customers and utilities when they wish to connect a renewable energy system to the grid. The process can be more burdensome and expensive for customers to connect when a state lacks comprehensive interconnection standards. Requirements and processes vary by state, applying to different types and sizes of systems, and each with varying degrees of definiteness. Technical issues related to interconnection are thoroughly addressed by the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems.

As a part of this technical assistance effort, interviews were conducted with each of the major Nebraska public power utilities to help assess the interconnection processes in Nebraska, and to identify potential barriers to solar deployment. Questions addressed the application process, such as whether fast track screens were in place, the standardization of the application, adoption of Power Clerk software, and associated costs. Table 12 summarizes the answers received throughout the interview process on the interconnection process.

Table 12: Interview answers regarding NPPD, LES, and OPPD interconnection processes

	Interview answers
NPPD	• **Process:** NPPD has a clear standardized application process for small generators <25kW; developing a standardized process for generators >25kW • **Application cost:** <25kW - no cost; >25kW - $5 per kW; if study

	shows transmission system impact - $25K deposit required • **Utility contact:** no dedicated staff; communications through account manager; field staff coordinates with customer • **Interconnection requirements:** language predominantly taken from FERC's SGIP process • **Numbers of systems:** 9 total PV systems – only one system over 25 kW
OPPD	• **Process:** DG manual available to customers • **Application cost:** • **Utility contact:** no dedicated staff; applications submitted to customer representative; system protection and engineering group review interconnection applications • **Interconnection requirements:** process does not follow FERC's SGIP recommendations • **Numbers of systems:** 10 DG applications per year
LES	• **Process:** Application for review plus design information • **Application cost:** No cost to applicant • **Utility contact:** one staffer dedicated • **Interconnection requirements:** process does not follow FERC's SGIP recommendations • **Numbers of systems:** 35-40 systems total; 5-8 applications per year

As shown in Table 12, each of the Nebraska utilities has an interconnection framework that is set up to process a relatively small number of distributed renewable energy system applications. If the utilities anticipate an expanding distributed solar PV market in their territories, it would be benefit to look at the interconnection process of utilities with substantial distributed solar PV in their territories. A current NREL research effort, funded by the U.S. Department of Energy, has interviewed a range of utilities (IOUs, municipalities, cooperatives) to determine "best practices" that enable efficient interconnection of renewables while maintaining safety and reliability at the utility level. Here is a preliminary, partial list of those "best practices" developed from the utility interviews, followed by a schematic that shows the typical interconnection process (shown in Figure 5).[25]

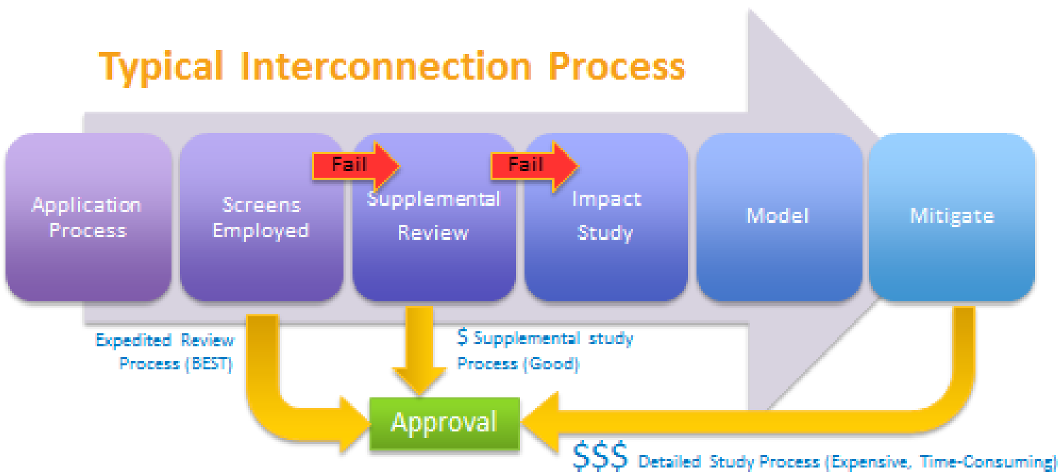
- Strong state interconnection rules – having state-level interconnection rules help all utilities and distributed generation (DG) developers in consistent and generally fair processes (for all parties). States such as California and New York have created interconnection processes that are clear and concise, and appear pragmatic in nature.
- Utilizing practical screens – utilities (and states) that incorporate practical screens in evaluating DG interconnection applications allow those systems that will not have a negative impact on the grid to interconnect quickly and at a low cost. The FERC SGIP is

[25] This preliminary list and figure were supplied by Michael Coddington, who is leading NREL's effort to document utility interconnection practices and develop "best practices".

used in many utility processes (or a version similar to SGIP) to evaluate fast-tract interconnection applications and allow quick evaluation (especially small PV systems).

- Utilizing supplemental screens – when the first level of screens fail, supplemental screens may be applied to quickly address a problem or to determine if the failed screen was not truly an issue. Failing the initial screens does not necessitate a full-on impact study phase that often costs thousands of dollars, is very time-consuming (for the utility engineers), and is often a deal-killer. Supplemental screens, where utilized, seem to be a practical approach and are a reasonable approach for all parties.
- Utilizing multiple-level interconnection agreement approach – utilizing multiple level criteria for interconnection allow developers and utility customers to choose the size and complexity of their interconnection agreement. An example follows:
    - Level 1 - Inverter–based, <10kW
    - Level 2 – Inverter based, <2MW and other DG <2MW
    - Level 3 – All DG >2MW
- Online forms and process – many utilities have clear and easy to use web sites that allow customers to download all necessary forms, and have ample information on the process and what to expect in terms of time and costs.
- Clear and concise mitigation measures – some utilities have specific mitigation approaches that are balanced for cost and ease of implementation. There may be solutions to potential interconnection problems that cost thousands of dollars rather than hundreds of thousands of dollars, and those are seen as both practical and customer friendly.

Figure 5: Illustration of typical interconnection process



4.2 Net Metering

At a basic level, net metering policies allow consumers to offset electricity bill costs by producing their own energy, as it allows customers to send excess energy back to the grid. Net metering policies start at the state level, establishing the system size limit allowable for net metering and total capacity of net metered systems. Importantly, net metering policies also establish reimbursement rates for excess generation, representing another crucial component of solar PV project economics. Table 13 provides an overview of the net metering policies of each of the top solar PV states, as they compare with Nebraska.

Table 13: Details of net metering policies in top ten states with the largest total nameplate capacity of solar PV installed through the end of 2012[26]

State	Extent of policy	Total program capacity	Max system size	Reimburse or credit rate
California	All utilities	Capped/5%	1,000kW	Retail
Arizona	IOUs, Co-ops	Unlimited	Limited to 125% of load	Retail
New Jersey	IOUs	Trigger	Limited to customer load	Retail
Nevada	IOUs	Capped/ 1%	1,000kW	Retail
Colorado	All utilities	Unlimited	25 kW for co-ops, munis	Retail
North Carolina	IOUs	Unlimited	1,000kW	Retail
Massachusetts	IOUs	Capped/1%	2,000kW	Retail
Pennsylvania	IOUs	Unlimited	3,000kW	Retail
Hawaii	All utilities	Unlimited	100kW	Retail
New Mexico	IOUs, Co-ops	Unlimited	80,000kW	Avoided cost
NEBRASKA	**All utilities**	**Capped /1%**	**25kW**	**Avoided cost**

As shown in Table 13, the top solar states generally require utilities to net meter much larger solar PV systems in comparison to Nebraska state policy. In addition, all of the top states (other than New Mexico) require all utilities regulated under the state's net metering policies to reimburse or credit net metered system owners at the retail electricity rate. The reimbursement rate for excess generation at retail rates gives systems in the top solar states a significant boost to project economics, causing considerable booms in distributed solar PV markets in several of these states – particularly third party owned lease systems. This boom has lead major utilities in Arizona, California, and Colorado to challenge state net metering policies, arguing that reimbursing solar customers at retail rates is leaving the utilities with stranded costs that are passed on to non-solar customers.[27]

The state of Nebraska has put in place net metering rules for all electric utilities, as indicated in Table 13. However, these state net metering policies set the floor, allowing utilities the flexibility to increase the system size limit and reimbursement rate for excess generation. Table 14 provides basic net metering information for each of Nebraska utilities.

Table 14: Net metering and renewable generation rate interview answers for Nebraska's utilities

	Interview answers
NPPD	• **System size limit:** 25 kW

[26] Data sourced from the Database of State Incentives (DSIRE)

[27] See http://www.greentechmedia.com/articles/read/arizonas-biggest-utility-proposes-to-a-cut-to-net-metering; http://www.greentechmedia.com/articles/read/Solars-Net-Metering-Fight-in-California-Previews-at-Intersolar; http://www.greentechmedia.com/articles/read/xcel-colorado-responds-to-the-solar-industry-on-net-metering.

	• **Reimbursement for excess generation**: excess monthly generation is credited to the customer at net metering rate - $0.0944/kWh summer, $0.0527/kWh winter; customer reimbursed cash for year-end excess
OPPD	• **System size limit:** 25 kW • **Reimbursement for excess generation**: true-up payment made each month and no roll-over; excess purchased at net metering rate - $0.04/kWh summer, $0.0352/kWh winter (cost of fuel)
LES	**Net Metering:** • **System size limit:** 25 kW • **Reimbursement for excess generation**: current retail residential rate until a total of 1 MW of customer owned renewable generation is installed system-wide; 50% of residential retail rate after 1 MW of customer owned renewable generation is installed system-wide; and avoided energy costs after 2 MW of customer owned renewable generation is installed system wide • **Capacity Payment**: One-time payment based on the avoided capacity costs for performance on system peak at $475/kWdc for PV solar facing west; $375/kWdc for PV solar facing south; no capacity payment for wind systems as no projected performance on system peak **Renewable Generation Rate:** • **System size limit:** >25 kW to 100 kW • **Reimbursement for excess generation**: current retail residential rate until a total of 1 MW of customer owned renewable generation is installed system-wide; 50% of residential retail rate after 1 MW of customer owned renewable generation is installed system wide; and avoided energy costs after 2 MW of customer owned renewable generation is installed system-wide • **Customer and Facility Charge**: $40.25/billing period • **Capacity Payment**: One-time payment based on the avoided capacity costs for performance on system peak at $475/kWdc for PV solar facing west; $375/kWdc for PV solar facing south; no capacity payment for wind systems as no projected performance on system peak

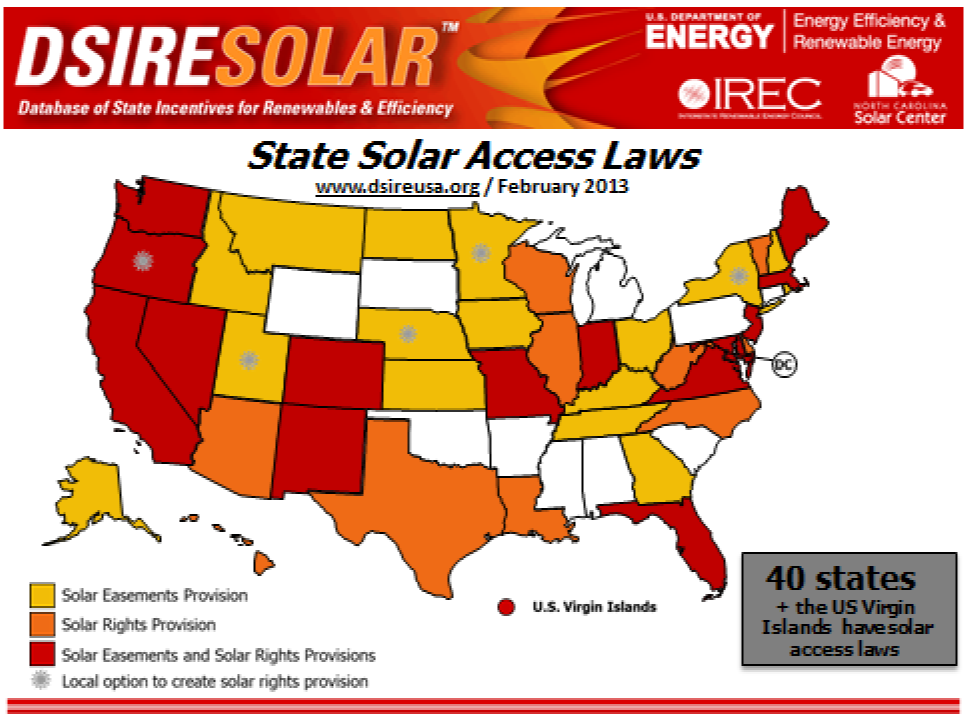
5 Homeowner associations

Homeowners and businesses can face local ordinances or homeowner association rules that prohibit or increase the cost of installing a solar PV system. Interviews with representative of the large public utilities in Nebraska revealed that there have been incidences in Nebraska where homeowner associations have prohibited homeowners in installing solar PV systems. This section briefly examines how barriers imposed by homeowner associations have been addressed in other states.

Across the U.S., solar rights laws have been passed at the state and local levels to address the barriers imposed by homeowner associations or local government ordinances. Solar rights laws grant protections by "limiting or prohibiting private restrictions (e.g., neighborhood covenants and bylaws, local government ordinances and building codes) on the installation of solar-energy systems."[28]

Solar rights laws are often grouped under a general category called solar access laws, which also include solar easements. Solar easements allow "the owner of a solar-energy system to secure rights to continued access to sunlight from a neighboring party whose property could be developed in such a way (e.g., building, landscaping) as to restrict the system's access to sunlight." Figure 6 illustrates how prevalent state solar access laws are across the U.S.

Figure 6: State solar access laws



Forty states have some form of solar access law in place, including Nebraska, which grants local governments the capacity to implement ordinances or regulations that grant or restrict solar rights. This decentralized regulatory environment—one in which localities can pass their own solar access laws—likely generates significant uncertainty for prospective purchasers of solar PV systems.

[28] More information found on the Database of State Incentives (DSIRE) Solar Policy Guide portal (http://www.dsireusa.org/solar/solarpolicyguide/?id=19)

Solar rights laws "typically limit restrictions that neighborhood covenants and/or local ordinances may impose on the installation of solar equipment." Many of these solar rights laws have been in place since the 1970s. Table 15 provides several examples of solar rights laws.

Table 15: Examples of state solar rights laws[29]

State	Key provisions
Hawaii	• Prohibits any covenant or restriction that restricts the installation or use of a solar energy system for any residential dwelling • Requires HOAs to pass rules in accordance with the solar rights law
Colorado	• Passed in 1979, the law prohibits any residential covenants that restrict solar access. • In 2008, several exceptions were inserted that allowed for aesthetic requirements that do not increase the costs of the solar PV system.
Texas	• Inserted into the Texas Property Code in 2011, the solar rights provision prohibits HOAs from creating or enforcing regulations that prohibit the installation of solar PV systems • Allows HOAs to prohibit systems for a variety of reasons, including, systems that extend above the roofline or do not conform with the roofline, systems that violate public health and safety, and ground mounted systems taller than a fence around a fenced yard. • As long as the solar PV system's performance is not adversely impacted, HOAs may also require where solar devices should be located on the roof.

As shown in Table 15, other states have passed solar rights laws that apply to all HOAs located within their jurisdictions. Such solar rights laws provide much more certainty to solar installers and potential solar customers relative a decentralized approach. Texas and Colorado illustrate how states are mitigating the concerns of HOAs, by granting HOAs some latitude in placing some restrictions on solar PV systems that overstep aesthetic or safety bounds.

6 Community-shared solar (solar gardens)

A community-shared solar PV system is loosely defined as a system that provides power and financial benefits to multiple community members. They can provide access to solar power for renters, or others who cannot install solar on their own homes or businesses. Aside from expanding access to solar power to community members, community-shared solar PV systems have several other advantages that are expected to result in reduced power prices for participants, including:[30]

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[29] Information accessed through the Database of State Incentives (DSIRE) Solar Policy Guide portal (http://www.dsireusa.org/solar/solarpolicyguide/?id=19)

[30] See the U.S. Department of Energy's *A Guide to Community Shared Solar: Utility, Private, and Nonprofit Project Development*, 2012.

- Larger sized projects will provide economies of scale, reducing the development and installation costs ($ per watt)
- Allows for optimal siting of projects, boosting the productivity of the system.

6.1 Enabling legislation

State policies and legislation are often required to enable the development of community-shared solar projects. Such policies can establish whether the solar project and group members must be located within the same utility service area, whether there should be a system size cap, whether there are allowable ownership structures, and regulate the permissible billing methods.[31]

Enabling legislation is not currently required for a utility in Nebraska to interconnect a solar garden. As a public power state, each municipal, public power district, or cooperative within the states currently is able to establish policies and procedures to interconnect a solar garden. However, legislation was introduced in 2013 that would allow community-shared solar projects to be constructed in Nebraska and requires the servicing utility to interconnect the system. Like Nebraska, other states have recently seen attempts to pass legislation that enables the development of community-shared solar projects. Many of these efforts have stalled, most prominently in California.[32]

However, some states have passed legislation in recent years to advance the development of community-shared solar projects. In particular, the Colorado General Assembly passed a bill in 2010 that directed the Colorado Public Utilities Commission to adopt new rules that would specify rebates and renewable energy credits can apply to community solar gardens.[33] The legislation specified that community solar garden projects qualify as retail distributed generation. Colorado's rules allow traditional net metering for utility customers purchasing or leasing shares of community solar gardens.

6.2 Public utility-sponsored community solar programs

Table 13 provides examples of several public utility-sponsored community solar programs and projects. They are of various sizes with a range of characteristics and provide a snapshot of programs being established by public utilities.

Table 13: Examples of public utility-sponsored community solar PV programs

Utility:	Description
Orlando Utilities Commission[34]	• Consists of one 400 kW solar PV system

[31] For more information, see the U.S. Department of Energy's *A Guide to Community Shared Solar: Utility, Private, and Nonprofit Project Development*, 2012.

[32] See the Solar Gardens Community Power blog for regular updates on the progress of community-shared solar legislation - http://blog.solargardens.org/2013/03/community-shared-solar-legislation.html.

[33] http://www.colorado.gov/cs/Satellite?blobcol=urldata&blobheader=application/pdf&blobkey=id&blobtable=MungoBlobs&blobwhere=1251643794208&ssbinary=true

[34] For more information, see http://www.ouc.com/environment-community/solar/community-solar; and the March 17th, 2013 Orlando Sentinel article *OUC customers can buy solar-generated electricity, lock in price for 25*

	• The system is owned, financed, built and maintained by ESA Renewables, LLC, as private solar developer who will utilize the federal tax incentives. • The utility will pay ESA Renewables $0.18/kWh under a PPA • Subscribers will sign up in 1 kW block increments, up to 15 kW; rate for subscribers is set at $0.13/kWh, fixed for up to 25 years. • The utility will subsidize the $0.05/kWh difference • Excess generation will be credited on subscriber's bill at the retail rate • System is fully subscribed
Sacramento Municipal Utility District[35]	• Solar Shares Program • As of 2013, the program had two 1 MW projects. • SMUD purchases power from solar developers under PPAs and resells the power to program participants. • Program participants pay a fixed monthly fee based on the amount of capacity they want to subscribe to (capped at 4 kW). • The participants receive monthly kWh credits at the full retail rate for the output of their share, which varies over the year • SMUD sells the power generated at a rate less than the PPA purchase price, subsidizing the program rates through surcharge funds
Tucson Electric Power[36]	• Bright Tucson Community Solar Program • As of July 2012, 777 program participants had purchased 4.13 MW of community-shared solar • Systems some systems are owned by Tucson Electric Power, an investor owned utility; while other systems are owned by third-party developers • Customers purchase 150 kWh blocks per month, locked in over 20 years • Current rates are $0.02/kWh more expensive than standard power • Excess purchases are carried forward to the next billing period as a credit.

years, http://articles.orlandosentinel.com/2013-03-17/business/os-buy-some-ouc-solar-energy-20130317_1_solar-panels-solar-power-solar-farm.

[35] For more information, see the U.S. Department of Energy's *A Guide to Community Shared Solar: Utility, Private, and Nonprofit Project Development*, 2012 - http://www.nrel.gov/docs/fy12osti/54570.pdf; and SMUD's Solar Shares Program page - https://www.smud.org/en/residential/environment/solar-for-your-home/solarshares/.

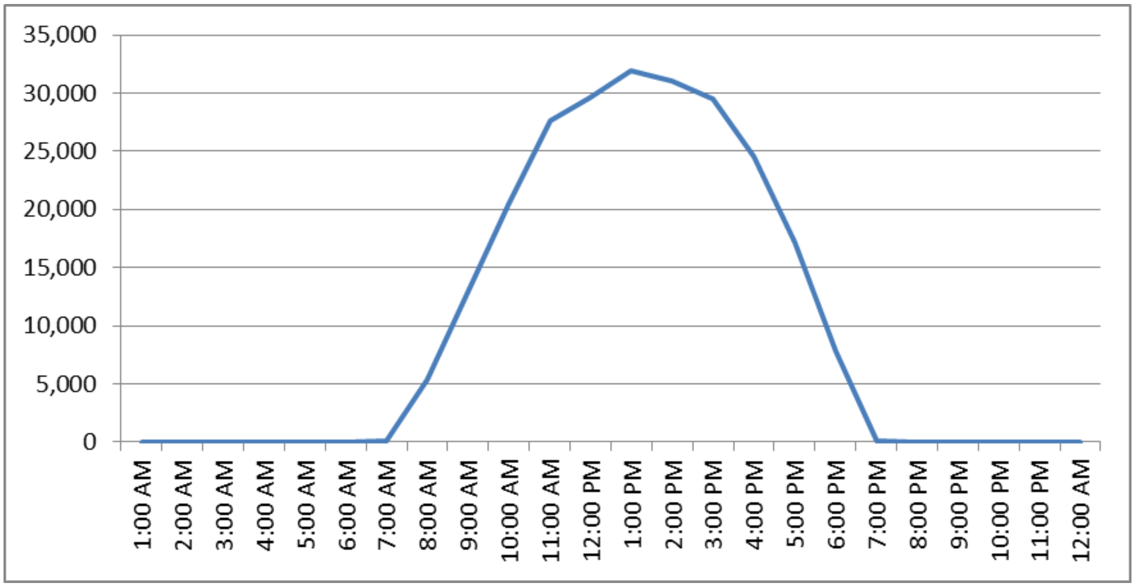
[36] For more information, see the U.S. Department of Energy's *A Guide to Community Shared Solar: Utility, Private, and Nonprofit Project Development*, 2012 - http://www.nrel.gov/docs/fy12osti/54570.pdf; and *IREC's Community-Shared Solar: Diverse Approaches for a Common Goal*, http://www.irecusa.org/wp-content/uploads/Community-Shared-Solar-Handout-final-010913.pdf

7 Solar PV and irrigation loads

The Nebraska State Energy Office and the Nebraska utilities requested information on how solar PV would impact the substantial irrigation load of NPPD, and to a lesser extent OPPD. The utilities have substantial irrigation load in the summer months, with NPPD alone having an irrigation load of 1600 MW in the summer. Conversations with NPPD indicate that the utility uses price signals that encourage agricultural customers to irrigate to off-peak times. An agricultural customer can cut electric bill in half by responding to the price signals set by NPPD. As a consequence, the utility (NPPD) has an irrigation load profile that peaks around 9 am and after 11 pm due to the large amount of irrigation load that is controlled between 9 am and 11 pm.

Photovoltaic solar generation systems generate energy during the daytime hours when there is solar irradiation present, and the peak output occurs at "solar noon" (assuming there are no clouds or obstructions at that time). Power and energy are generated from dawn to dusk, but most energy is produced at solar noon +/- 3 hours. Figure 7 shows a predicted diurnal production curve from a solar PV system during the summer in Nebraska.

Figure 7: Modeled hourly production (in kWh) for a 50 kW system in Nebraska on August 1[37]



Irrigation loads, like most customer loads, are predictable but not always controllable. Some utilities may choose to offer incentivized rates for agricultural customers (as well as other rate classes from time to time), which may help the peak load of a feeder or for the utility system. However, most of these rate classes have no real control on the equipment, so the incentive is used to control behavior of the loads. In the case of NPPD, the vast majority of the utility's rural wholesale customers have controls on irrigation pumps that are operated by the utility when they need to manage their kW load. In one case, the utility offers time of use metering and has no direct control.

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[37] PVWatts (http://www.nrel.gov/rredc/pvwatts/grid.html) was used to model production. The location was Grand Island, NE. The default settings in PVWatts were used – fixed tilt at 41 degrees and azimuth of 180.

PV systems produce energy in a diurnal nature, and thus may be able to contribute to agricultural load service if the loads are operated in the time interval of solar noon +/- 3 hours (approximately). However, PV systems will experience days and time intervals where production of energy is a fraction of the peak output capability, and thus cannot be counted on to serve loads at any given time. Therefore, utility feeder design, and substation design, must be designed to serve all loads as if there were no PV or other DG present.

For the purposes of this technical report, the authors contacted several utilities about the integration of solar PV systems into center pivot irrigation agricultural operations. None of the utilities contacted had examples of such integrated systems. Several were interested in the concept, but, for the most part, the utilities indicated that they would consider a net metered, solar PV, center pivot irrigation system as another distributed generation system.