2014

Annual Report: The Costs and Benefits of Renewable Resource Procurement in Illinois Under the Illinois Power Agency and Illinois Public Utilities Acts

Submitted to the Illinois General Assembly and the Illinois Commerce Commission Pursuant to PA 97-0658

Illinois Power Agency

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IPA

ILLINOIS POWER AGENCY

Anthony M. Star, Director

March 31, 2014

The Honorable Members of the Illinois General Assembly
State House
Springfield, Illinois

The Honorable Chairman and Commissioners of the Illinois Commerce Commission
527 E. Capitol Avenue
Springfield, Illinois

Dear Honorable Members of the Illinois General Assembly and the Illinois Commerce Commission:

Pursuant to 20 ILCS 3855/1-75(c)(5) and 220 ILCS 5/16-115D(d)(4) as amended by Public Act 97-0658, the Illinois Power Agency submits the attached *Annual Report on The Costs and Benefits of Renewable Resource Procurement in Illinois Under the Illinois Power Agency and Illinois Public Utilities Acts*.

The data and analyses contained herein provide important insight into the impacts of Illinois' Renewable Portfolio Standards on electricity consumers and on the State overall, as well as policy guidance on future renewable resource procurement activity.

Sincerely,

Anthony M. Star

Anthony M. Star
Director

160 North LaSalle Street, Suite N-504, Chicago, Illinois 60601

Table of Contents

ANNUAL REPORT ON THE COSTS AND BENEFITS OF RENEWABLE RESOURCE PROCUREMENT IN ILLINOIS UNDER THE ILLINOIS POWER AGENCY AND ILLINOIS PUBLIC UTILITIES ACTS

MARCH 31, 2014

I. Executive Summary and Key Findings

Public Act 97-0658, effective January 13, 2012, established reporting requirements for the Illinois Power Agency (IPA), shown below:

> <u>*Utility Renewable Resource Costs and Benefits*</u>
>
> *Beginning April 1, 2012, and each year thereafter, the Agency shall prepare a public report for the General Assembly and Illinois Commerce Commission that shall include, but not necessarily be limited to:*
>
> > *(A) a comparison of the costs associated with the Agency's procurement of renewable energy resources to (1) the Agency's costs associated with electricity generated by other types of generation facilities and (2) the benefits associated with the Agency's procurement of renewable energy resources; and*
> >
> > *(B) an analysis of the rate impacts associated with the Illinois Power Agency's procurement of renewable resources, including, but not limited to, any long-term contracts, on the eligible retail customers of electric utilities.*
>
> *The analysis shall include the Agency's estimate of the total dollar impact that the Agency's procurement of renewable resources has had on the annual electricity bills of the customer classes that comprise each eligible retail customer class taking service from an electric utility. The Agency's report shall also analyze how the operation of the alternative compliance payment mechanism, any long-term contracts, or other aspects of the applicable renewable portfolio standards impacts the rates of customers of alternative retail electric suppliers.*
>
> <u>*Alternate Retail Electric Supplier (ARES) Renewable Resource Costs and Benefits*</u>
>
> *Beginning April 1, 2012 and by April 1 of each year thereafter, the Illinois Power Agency shall submit an annual report to the General Assembly, the Commission, and alternative retail electric suppliers that shall include, but not be limited to:*
>
> > *(A) the total amount of alternative compliance payments (ACP) received in aggregate from alternative retail electric suppliers by planning year for all previous planning years in which the alternative compliance payment was in effect;*
> >
> > *(B) the amount of those payments utilized to purchase renewable energy credits itemized by the date of each procurement in which the payments were utilized; and*
> >
> > *(C) the unused and remaining balance in the Agency Renewable Energy Resources Fund attributable to those payments.*

This report is submitted in accordance with this Act. Its analysis includes the costs and benefits associated with the following renewable resource purchases facilitated by the IPA under procurements either mandated by the legislature or conducted in accordance with Illinois Commerce Commission (ICC) reviewed and approved IPA procurement plans, described below:

Ameren Illinois Company (Ameren) Procurements

05/18/09 Renewable Energy Credit (REC) Procurement

05/18/10 REC Procurement

12/10/10 20-Year Bundled REC and Energy Procurement

05/18/11 REC Procurement

02/16/12 Rate Stability REC Procurement

05/10/12 REC Procurement

Commonwealth Edison Company (ComEd) Procurements

05/11/09 REC Procurement

05/18/10 REC Procurement

12/10/10 20-Year Bundled REC and Energy Procurement

05/18/11 REC Procurement

02/16/12 Rate Stability REC Procurement

05/10/12 REC Procurement

Deliveries under some of these procurement events are to be made beyond the period for which actual costs are reported herein. The report includes discussion of the contracted costs and deliveries under historic periods that are analyzed in terms of specific rate impacts. Renewable energy rate impacts on a cents per kWh basis depend upon the kWh deliveries in each rate class.

Key Findings

- In the ComEd territory, the cost of purchasing renewable energy resources ranged from a high of 1.927 cents per kilowatt-hour in the IPA's first procurement in 2009 to a low of 0.088 cents per kilowatt-hour in the 2012 procurement. One-year renewable energy credits procured for subsequent years in the 2012 Rate Stability Procurement were more expensive (0.128 c/kWh for delivery in 2013-4, for example). The Agency also procured long-term power purchase agreements on behalf of ComEd in 2010, which included an implied REC price near the high end of the range described. The purchases represent a low of 0.05% to a high of 1.68% of the total rates paid for electricity by single-family homes without electric space heat[1] (the greatest impact being seen in the current year).

- In the Ameren territory, the cost of purchasing renewable energy resources ranged from a high of 1.586 cents per kilowatt-hour in the 2009 procurement to a low of 0.092 cents per kilowatt-hour in the 2011 procurement. While the price trend for renewable energy credits was downward through 2011, the REC price in the 2012 procurement was about 50% higher than in 2011. The Agency also procured long-term power purchase agreements on behalf of Ameren in 2010 that included an implied REC price near the high end of the range described. Purchases represent a low of 0.05% to a high of 1.64% (current year) of the total rates paid for electricity by residential customers.

- Wind and solar power are dependent on intermittent energy sources – wind and sun – and there is concern that as the fraction of electricity supplied by intermittent generation grows, additional resources and or more complex control systems will be needed to maintain the stability and reliability of the power system. A number of studies of these "renewable integration costs" were reviewed in the 2013 Annual Report on the Costs and Benefits of Renewable Resource Procurement in Illinois; those studies provided integration cost estimates ranging from $1/MWh to $12/MWh.[2] There appears to be only minor concern over the operational impacts of penetration rates below 10%. Illinois currently obtains 4.8% of its generation from these intermittent sources, and combined with neighboring states, the level is approximately 9.3%.

- The Illinois Power Agency has been presented with evidence that the Illinois Renewable Portfolio Standard (RPS) appears to have enabled significant job creation and economic development opportunities as well as environmental benefits. These results cannot be extrapolated indefinitely, as factors such as market prices for energy, transmission constraints, and uncertainty in the load serving responsibility will affect the cost-effectiveness of further additions to the renewable resource generation stock in Illinois. Further, the impact of retail load shifts from utility service to alternative suppliers due to factors such as municipal aggregation will have an impact on procurement options that are available as incentives for any further build-out of renewable resources.

- In principle, low marginal cost renewable generators could undercut and offset electricity offered into the markets by coal-fired and nuclear generators, which are two important sources of electricity and capacity in Illinois and important factors in Illinois' economy. If those plants' gross energy margins were reduced, they may require higher capacity prices to continue operation. Over the last five years, coal-fired energy has represented a declining fraction of the supply mix in MISO and

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[1] Rate impacts vary by customer class and are reported here for ComEd's largest customer class, Single Family Without Space Heat. For Ameren the largest customer class is Residential Service. For a full breakdown of rate impacts by customer class, see Table III-6 for ComEd and Table III-8 for Ameren.

[2] One MWh equals one thousand kilowatt-hours (kWh). MWh are typically used for wholesale transactions while kWh are used for retail transactions. Therefore the $1/MWh to $12/MWh range for the cost of renewables integration translates into a retail cost to consumers ranging from one tenth of a cent to 1.2 cents per kWh.

PJM; so far, that decline has generally reflected fossil fuel economics (coal-to-gas switching) more than loss of market share to renewables.

- The IPA's renewables procurements on behalf of the utilities are limited to the dollar amount of the utilities' renewables budget cap (rate impact). The IPA thus faces a unique challenge with regard to rate impacts. The IPA traditionally procured renewable resources only on behalf of a subset of Illinois electric users (called "bundled service customers" or "eligible retail customers") who may join or leave IPA-procured service at any time. As a result, even if the IPA made extremely prudent purchases of renewable resources relative to prevailing market prices, the rate impact will be more significant if a portion of its customers decide to use other supply options. This is because the IPA must procure renewable resources on a forward-looking basis, and the costs for those resources are subsequently allocated across the bundled service customers that actually take that service.

- The IPA may also procure RECs using the Renewable Energy Resource Fund. The Renewable Energy Resources Fund is collected from Alternative Retail Electric Suppliers ("ARES") on an annual basis, prior to any procurements or expenditures being made. It therefore does not have a rate cap (or rate impact), but annual contributions can vary widely depending on the Alternative Compliance Rate and the market share of the ARES.

- The Alternative Compliance Payment (ACP) mechanism is a useful construct for ARES compliance with RPS standards in a way that is competitively neutral. It allows an opportunity for the additional costs of renewable resources to be the same, on an average cents per kilowatt-hour (kWh) basis, regardless of whether a customer takes electricity supply from a utility or an ARES. The pooling of these funds also allows for long-term contracting, which ARES are less likely to undertake due to market pressures and the shorter horizon of standard ARES supply contracts.

- In September of 2013, the balance in the ACP-funded IPA Renewable Energy Resources Fund (RERF) more than tripled, reaching $53 million. In May 2013, the IPA signed contracts implementing its plan to use money from the RERF fund to purchase RECs curtailed from the 2010 Long-Term Power Purchase Agreements. It began recording expenditures during the second half of state fiscal year 2014.

- Spending out of the RERF has been minimal and restricted to a few products with limited availability. This is due to restrictions in the enabling statute combined with market conditions that were likely unforeseen by the framers of the IPA Act. The IPA remains an active participant in dialogue to resolve these issues and spend the RERF as the General Assembly intended.

- The Illinois Power Agency Act requires the IPA to reserve some of its future renewable procurement for solar photovoltaics. Several northeastern states, whose solar resource is not very different from what is available in Illinois, have successfully incentivized photovoltaic installation and the development of solar REC (SREC) markets. Recent SREC prices in these markets have varied from $70 to $250, showing the influence of local and regulatory factors. While specific State mandates impact SREC prices, the experience of those states may provide insights into the potential for a SREC market that could develop in Illinois.

II. Report Methodology

This Report draws upon publicly available data regarding electric utility load, procurement results, and ACP fund reporting. Although the RPS has been in place since June 1, 2008, the Agency was not required to conduct a renewable energy resource procurement event until 2009, for delivery beginning June 1, 2009. Given the statutory directive to examine "the Agency's procurement,"[3] this report focuses its analysis on the years 2009 through 2013. There is no specific definition of either "costs" or "benefits" in the IPA Act. For the purposes of this report, tabulated "costs" are defined as the final amount settled for a renewable resource as publicly reported, and "benefits" are defined as both quantitative and qualitative economic and societal impacts. The report also includes discussion of costs that could potentially be incurred in the future but which have either not yet become significant (intermittency and renewables integration) or depend on policy or procurement choices (specifically solar RECs).

This Report also includes estimates of bill impacts based on eligible customer class load, numbers of customers and bill estimates contained in publicly available utility tariff and rate case filings.[4] For the purposes of determining the total bill impact, this Report includes the same costs included in the statutory RPS spending cap: "the total amount paid for electric service [which] includes without limitation amounts paid for supply, transmission, distribution, surcharges, and add-on taxes."[5] The bill impacts are presented both in terms as a percentage of an average customer bill for that class and as cents per kilowatt-hour.

For background information on the Illinois Power Agency, the Illinois Renewable Portfolio Standard, and Alternative Retail Electric Supplier compliance with the RPS, please see Section II of the 2012 edition of this Report which is available on the IPA website at: http://www2.illinois.gov/ipa/Pages/IPA_Reports.aspx.

The IPA would like to thank ComEd and Ameren for their assistance in providing data necessary for this Report. The IPA also would like to thank PA Consulting Group, the agency's procurement planning consultant, for their assistance in preparing this Report.

[3] 20 ILCS 3855/1-75(c)(5).

[4] For ComEd, this includes ICC Dockets 07-566 and 10-0467; for Ameren, this includes ICC Dockets 07-0585, 09-0306 and 11-0279 (later withdrawn).

[5] 20 ILCS 3855/1-75(c)(2).

III. Renewable Resource Procurement Impact

A. Cost Comparison

"[T]he Agency shall prepare a public report … that shall include … a comparison of the costs associated with the Agency's procurement of renewable energy resources to (1) the Agency's costs associated with electricity generated by other types of generation facilities."[6]

Results are presented for each electric utility below. In order to place the costs of renewable resources and conventional supply resources on a level footing, procurement costs are compared by year of delivery to the utility's customers. For each delivery year, the following costs are tabulated:

- The actual average cost of RECs procured by the Agency in that year's procurement;
- The actual average cost of energy (and for Ameren, capacity) procured by the Agency from conventional supply sources in that year's procurement;
- The 2010 Long-Term Power Purchase Agreements (LTPPA) purchase costs broken down to show the imputed REC and energy prices[7], beginning with the June 2012 – May 2013 delivery year, which is the first year of delivery under those agreements; and
- The 2012 Rate Stability Procurement costs of RECs and energy, beginning with the June 2013 – May 2014 delivery year, which is the first year of delivery under those agreements.

With regard to the 2010 LTPPA, the contracts contain bundled pricing for energy and RECs. REC prices are "imputed" by subtracting an energy price from the bundled price. The energy prices are based on a forward energy curve calculated at the time of the procurement event. The process of imputing these REC prices is described in Appendix K to the Agency's 2010 Procurement Plan.[8]

Although the Agency's costs associated with procuring RECs are compared to the Agency's costs associated with procuring energy from conventional supply sources below, it should be noted that these costs are not for equivalent products. RECs represent only the value of the environmental attributes of a certain amount of energy produced from renewable energy resources, not the value of the underlying energy. On the other hand, the values shown for energy produced from conventional supply sources represent prices of actual energy procured for use by the end customer. In general, the REC costs are additive to the conventional supply costs when calculating individual customer rate and bill impacts.

The ICC has approved the IPA's procurement of RECs to comply with the entirety of the utilities' RPS-mandated volumes:

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[6] 20 ILCS 3855/1-75(c)(5)(A).

[7] In its Dec. 19, 2012 order (note 14 *infra*) the ICC allowed for the release of the previously confidential "Appendix K" imputed REC prices. The conformed plan (Ill. Power Agency, Ill. Commerce Commission Docket 12-0544, 2013 Electricity Procurement Plan Conforming to the Commission's December 19, 2012 Order at 84) included imputed prices for the five subsequent Plan Years 2013-2017.

[8] Ill. Power Agency, Ill. Commerce Commission Docket 09-373, Supplemental Filing (Nov. 9, 2010).

- For the 2009 procurement, the ICC approved the IPA's plan to purchase RECs for delivery from June 2009 – May 2010 to fulfill the RPS mandate for that period and stated: "the IPA is not permitted to undertake the acquisition of multi-year or long-term renewable resources."[9]
- For the 2010 procurement, the ICC agreed with the IPA's proposal to procure RECs on a short-term basis, for delivery from June 2010 – May 2011.[10] The ICC additionally found that the 2010 LTPPA "will supplement the short-term REC acquisition," and approved the IPA's revised plan to enter into LTPPAs for renewable energy supplies "outside of the RPS."[11]
- For the 2011 procurement, the ICC found that "a REC is a renewable energy resource and therefore fully meets the requirement of Section 1-20 of the IPA Act requiring the procurement of renewable energy," and approved the IPA's plan to procure unbundled one-year RECs for delivery from June 2011-May 2012.[12]
- For the 2012 procurement, the ICC agreed with the IPA's proposal to include one-year RECs and to procure the minimum unbundled RECs required under the solar and wind REC carve-outs, taking into account LTPPA volumes for delivery from June 2012 – May 2013.[13]
- No REC procurements were conducted during 2013. The ICC approved[14] the IPA recommendation that there should be no new Ameren or ComEd REC procurement event in the 2013 Procurement Plan taking into account June 2012 – May 2013 REC volumes from the 2012 Rate Stability Procurement and anticipated LTPPA deliveries.[15]
- As part of the approval of the IPA's 2013 Procurement Plan, the ICC also approved a "curtailment" of the LTPPAs. The curtailment was the trigger of a contract term that allowed the ICC to order Ameren and ComEd to only take enough from the LTPPA so that the rate cap in Section 1-75(c)(2)(E) of the IPA Act was not exceeded. The LTPPA holders accepted a temporary (annually reviewed) curtailment, but also had the contractual option to permanently curtail the contracts or to terminate the LTPPAs. The ICC authorized supplemental payments to the LTPPA-holders out of a non-bundled customer fund, and the IPA used RERF funds to offer to purchase curtailed RECs. Based upon updated forecasts in March 2013 curtailments only applied to the ComEd LTPPAs.

The IPA has recommended that there should be no new Ameren or ComEd procurement event in the 2014 Procurement Plan.[16] The basis for the IPA's recommendation was that the rate cap from Section 1-75(c)(2)(E) was projected to be exceeded again in the 2014-15 delivery-year. It made little sense to procure

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[9] Ill. Commerce Commission, Docket 08-0519, Final Order at 45 (Jan. 7, 2009).

[10] Ill. Commerce Commission, Docket 09-0373, Final Order at 127 (Dec. 28, 2009).

[11] Ill. Commerce Commission, Docket 09-0373, Final Order at 126, 115, 43 (Dec. 28, 2009).

[12] Ill. Commerce Commission, Docket 10-0563, Final Order at 83 (Dec. 21, 2010).

[13] Ill. Commerce Commission, Docket 11-0660, Final Order at 84 (Dec. 21, 2011); Ill. Power Agency, Ill. 2012 Power Procurement Plan Updated at 53 (Feb. 17, 2012).

[14] Ill. Commerce Commission Docket 12-0544, Final Order (Dec. 19, 2012).

[15] Ill. Power Agency, Ill. Commerce Commission Docket 12-0544, 2013 Electricity Procurement Plan at 83-84 (Sept. 28, 2012).

[16] Ill. Power Agency, Ill. Commerce Commission Docket 13-0546, 2014 Electricity Procurement Plan at 102 (Sept. 30, 2013).

additional renewable energy resources that would increase the required curtailment of the LTPPAs. The ICC Final Order for the 2014 Procurement Plan is currently on rehearing on issues involving renewable energy and, therefore, the 2014 Procurement Plan's approach to renewable resources is not final. However, the ICC took rehearing on issues other than the ICC's approval of the IPA's recommendations that no new renewable resource procurements take place in 2014.

1. ComEd

ComEd's previously purchased RECs are forecasted to fall short of the target by a relatively small amount for the June 2014 – May 2015 delivery year. However, ComEd expects to exceed the renewables cost cap and therefore cannot procure any additional renewables. Table III-1 shows the relative cost comparison of RECs and Conventional Supply for ComEd.

Delivery Year	Avg. Cost of RECs Procured by IPA in the Delivery Year (¢/kWh)	Avg. Cost of Conventional Supply Procured by IPA in the Delivery Year (¢/kWh)
June 2009 – May 2010	1.927	3.281
June 2010 – May 2011	0.488	3.344
June 2011 – May 2012	0.095	3.684
June 2012 – May 2013:		
2012 Procurement Plan	0.088	3.058
2010 LTPPA Purchases	1.671[17]	3.806[18]
Load-weighted average	0.839	3.608
June 2013 – May 2014:		
2010 LTPPA Purchases	1.697[19]	3.855[20]
2012 Rate Stability[21]	0.128	3.257
Load-weighted average	0.926	3.402
June 2009 – May 2014[22]	**0.833**	**3.419**
June 2014 – May 2015:		
2010 LTPPA Purchases	1.838[23]	3.903
2012 Rate Stability[24]	0.165	3.339
Load-weighted average	1.258	3.476

Table III-1: Relative Cost Comparison of RECs and Conventional Supply on a Cent per Kilowatt-hour Basis for ComEd[25]

[17] Imputed – calculated using actual REC deliveries during the 2012-13 Planning Year.

[18] Energy supply cost is calculated based on actual energy deliveries during the 2012-13 Planning Year.

[19] Imputed – calculated using budgeted REC deliveries for the 2013-14 Planning Year and 2012-13 Replacement RECs delivered at no cost during the 2013-14 Planning Year.

[20] Shown as "N/A" in 2013 Annual Report. This also affects the Load-weighted average in this column.

[21] Load-weighted average of the first year of delivery, June 2013-May 2014.

[22] Load-weighted average.

[23] Imputed.

[24] Load-weighted average of the second year of delivery, June 2014-May 2015.

[25] This is a relative cost comparison and NOT a calculation of rate impacts. Each year had different volumes of peak and off-peak energy secured in different months and the number of RECs procured is a small percentage of the amount of kWh of energy supplied (determined by the RPS for that particular delivery year). Sections III(C) and III (D) below provide an analysis of rate impacts, which factors in the RPS' effect on volume.

2. Ameren

Ameren's forecasted total and wind REC requirements for delivery beginning June 1, 2014 have been more than met by purchases under the 2010 LTPPA and the separate Rate Stability Procurement of renewable energy resources conducted in February 2012 pursuant to Public Act 97-0616.[26] Ameren is forecasted to fall short of its photovoltaic and distributed renewable requirements. In the 2014 Procurement Plan, the IPA projected that the RPS budget cap would require Ameren to curtail deliveries under the LTPPAs but based on the revised load forecast provided in March, 2014, no curtailment will be required.[27] Table III-2 shows the relative cost comparison of RECs and conventional supply for Ameren.

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[26] Note 16 *supra*.

[27] *Id*. at 103.

Delivery Year	Avg. Cost of RECs Procured by IPA in the Delivery Year (¢/kWh)	Avg. Cost of Conventional Supply Procured by IPA in the Delivery Year[28] (¢/kWh)
June 2009 – May 2010	1.586	3.682
June 2010 – May 2011	0.405	3.114
June 2011 – May 2012	0.092	3.234
June 2012 – May 2013:		
2012 Procurement Plan	0.115	2.863
2010 LTPPA Purchases	1.223[29]	3.787[30]
Load-weighted average	0.645	3.268
June 2013 – May 2014:		
2010 LTPPA Purchases	1.139[31]	3.842[32]
2012 Rate Stability[33]	0.343	2.951
Load-weighted average	0.790	3.036
June 2009 – May 2014[34]	**0.712**	**3.274**
June 2014 – May 2015:		
2010 LTPPA Purchases	1.359[35]	3.889
2012 Rate Stability[36]	0.257	3.144
Load-weighted average	0.942	3.215

Table III-2: Relative Cost Comparison of RECs and Conventional Supply on a Cent per Kilowatt-hour Basis for Ameren[37]

[28] Includes costs of both energy and capacity resources, procured through IPA-managed procurements and required to meet MISO capacity rules.

[29] Imputed – calculated using actual REC deliveries during the 2012-13 Planning Year.

[30] Energy supply cost is calculated based on actual energy deliveries during the 2012-13 Planning Year.

[31] Imputed – calculated using budgeted REC deliveries for the 2013-14 Planning Year and 2012-13 Replacement RECs delivered at no cost during the 2013-14 Planning Year.

[32] Shown as "N/A" in 2013 Annual Report. This also affects the Load-weighted average in this column.

[33] Load-weighted average of the first year of delivery, June 2013-May 2014.

[34] Load-weighted average.

[35] Imputed.

[36] Load-weighted average of the second year of delivery, June 2014-May 2015.

[37] This is a relative cost comparison and not a calculation of rate impacts. The number of RECs procured is a small percentage of the amount of kWh of energy supplied (determined by the RPS for that particular delivery year). Sections III(C) and III(D) below provide an analysis of rate impacts, which factors in the RPS' effect on volume.

3. Costs of intermittency

According to statistics published by the U.S. Energy Information Administration, in 2013 Illinois' electric power sector ranked fifth among U.S. states in wind production (Table III-3), maintaining the same rank Illinois occupied in 2012. Wind and solar power are dependent on uncertain and unpredictable energy sources – the wind and sun – and there is some concern that as the fraction of electricity supplied by intermittent generators grows, additional resources and or more complex control systems will be needed to maintain the stability and reliability of the power system.

	State	2013 Generation from Wind (GWh)
1	Texas	35,937
2	Iowa	15,571
3	California	13,230
4	Oklahoma	10,881
5	**Illinois**	**9,607**
6	Kansas	9,430
7	Minnesota	8,065
8	Oregon	7,452
9	Colorado	7,382
10	Washington	7,008

*Source: U.S. Energy Information Administration, **Electric Power Monthly**, February 2014*

Table III-3: Top Ten Wind Generating States, 2014

Although Illinois produced a large amount of wind energy in an absolute sense, this was still a small fraction (4.8%) of its total 2013 production, which is a slight increase from the 4.0% penetration ratio in 2012. Note that the statutory RPS standard, which is 9% by June 1, 2014, is based on the ratio of renewable supply to total retail consumption for each utility individually; the ratio of in-state renewable production to total in-state renewable production is used for comparability with available data for other states. In order for intermittent generation to have a noticeable operational impact on the power system, it should represent a sizable fraction of total generation.[38] That fraction indicates the intermittent penetration. Table III-4 shows the states with the largest intermittent penetrations in 2013. None of the first 9 states in this table generated more than 80,000 GWh in 2013 -- the largest among them, Oklahoma, ranked 22nd among the states in net generation. The most significant change in intermittent generation from 2012 to 2013 was a nearly 50% increase in California.

[38] The EPRI Impacts of Wind Generation Integration study reviewed for the 2013 Annual Report states that most power systems can reliably accommodate up to 10% wind penetration (as a percentage of annual energy load) with minor cost and operating impacts.

	State	2013 Intermittent Generation (GWh)	2013 Net Generation (GWh)	Penetration (Ratio)
1	Iowa	15,571	56,876	27.4%
2	South Dakota	2,688	10,358	26.0%
3	Kansas	9,430	48,645	19.4%
4	Idaho	2,545	15,742	16.2%
5	Minnesota	8,065	51,263	15.7%
6	North Dakota	5,530	35,361	15.6%
7	Oklahoma	10,881	73,576	14.8%
8	Colorado	7,581	53,396	14.2%
9	Oregon	7,474	60,165	12.4%
10	California	17,095	199,998	8.5%
11	Wyoming	4415	52,395	8.4%
12	Texas	36,113	433,526	8.3%
13	Maine	1,045	14,079	7.4%
14	New Mexico	2,602	36,042	7.2%
15	Washington	7,009	113,321	6.2%
16	Montana	1,661	27,573	6.0%
17	Hawaii	528	9,814	5.4%
18	Nebraska	1799	37,197	4.8%
19	**Illinois**	**9,671**	**202,891**	**4.8%**
20	Vermont	255	6,921	3.7%

Source: U.S. Energy Information Administration, ***Electric Power Monthly****, February, 2014*

Table III-4: Top Twenty States by Intermittent Penetration (Ratio of Intermittent to Net Generation), 2013

This should imply that intermittent generation is not a large enough part of the total in Illinois to impact system operations. However, Illinois is interconnected with its neighboring states, and Illinois utilities are part of the PJM and MISO RTOs. The nearby states of Iowa and Minnesota rank first and fifth in renewable penetration and when Illinois is considered together with its neighboring states of Wisconsin, Minnesota and Iowa, the collective renewable penetration is 9.3% (Table III-5), which is up from the 8.5% penetration rate for the region in 2012. This is a large enough penetration to potentially create concerns about additional operational costs associated with intermittency. Independent studies reviewed below indicate that such concerns may arise at penetration levels above 10%.

State	2013 Intermittent Generation (GWh)	2013 Net Generation (GWh)	Penetration (Ratio)
Illinois	9,671	202,891	4.8%
Iowa	15,571	56,876	27.4%
Wisconsin	1,562	65,587	2.4%
Minnesota	8,065	51,263	15.7%
TOTAL	34,869	376,617	9.3%

Table III-5: Renewable Penetration in Illinois Combined with its Northwestern Neighbors

The 2013 Annual Report on the Costs and Benefits of Renewable Resource Procurement in Illinois Under the Illinois Power Agency and Illinois Public Utilities Acts ("2013 Annual Report") contained a detailed review of a number of existing studies that attempted to quantify the costs associated with increased penetration of intermittent renewables. The review included many factors considered in the studies: the impact on system's load and generation, flexibility requirements, changes in system reliability requirements, weather forecasts, scheduling of generation and transmission requirements. The 2011 Wind Technologies Market study from the U.S. DOE reported integration cost ranging from less than $1/MWh to $12/MWh for various percentages of wind penetration in a market, which the 2013 Annual Report characterized as consistent with other studies' estimates.

Please refer to the 2013 Annual Report for a complete description of the review of existing studies on the costs of intermittency. The main findings from the studies that were judged to be relevant to the MISO and PJM areas were:

- Integration cost estimates range from less than $1/MWh to $12/MWh
- An EPRI study[39] states that most power systems can reliably accommodate up to 10% wind penetration (as a percentage of annual energy load) with minor cost and operating impacts
- Benefits due to reduced CO_2 emissions and fossil fuel usage from the development of wind and solar generation are significant
- The primary challenge associated with intermittency is the magnitude and timing of ramping requirements.

The U.S. Department of Energy's National Renewable Energy Laboratory (NREL) in a recent report, *Active Power Controls from Wind Power*, suggests that under certain market design conditions and with appropriate technical settings and control systems, wind resources could become an asset in terms of bulk system reliability.[40] According to the report more research is still needed.

B. Cost/Benefit Comparison

"[T]he Agency shall prepare a public report … that shall include … a comparison of the costs associated with the Agency's procurement of renewable energy resources to … (2) the benefits associated with the Agency's procurement of renewable energy resources."[41]

This is of necessity a combination of a quantitative and qualitative analysis. The costs are described in Section III.A above, and the benefits are described below.

1. Environmental Benefits

The environmental benefits of renewable energy resources are mainly associated with the benefits of avoiding the use of traditional generation sources that emit regulated pollutants. For example, the United States Environmental Protection Agency (EPA) has found that emissions of carbon dioxide (CO_2), methane

[39] Id.

[40] http://www.nrel.gov/docs/fy14osti/60574.pdf.

[41] 20 ILCS 3855/1-75(c)(5)(A).

(CH_4), nitrous oxide (NO_2), hydro fluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) may reasonably be anticipated to endanger public health and welfare.[42] Traditional generation from power plants include air emissions responsible for approximately one-third of nitrogen oxide emissions, two-thirds of sulfur dioxide emissions, and one-third of carbon dioxide emissions nationally, emissions associated with lung diseases such as asthma and chronic obstructive pulmonary disorder.[43] Renewable energy sources can avoid or reduce these air emissions, as well as reduce water consumption, thermal pollution, waste, noise, and adverse land-use impacts[44].

Environmental benefits can be measured in terms of annual emission benefits, that is, the benefits of not using traditional generation sources such as coal or natural gas fired power plants that emit restricted pollutants.

In the 2012 Report, the IPA estimated the emissions reductions impact of all renewable generation in Illinois, not just the generation attributable to IPA procurements. This model used a simulation of the entire regional electric grid and therefore did not single out the impacts of individual generation facilities or the specific procurements conducted by the IPA. The IPA, for the next *Annual Report on the Cost and Benefits of Renewable Resource Procurement*, plans to examine estimates of emissions reductions resulting from IPA purchases of renewable resources.

2. Economic Benefits

Illinois currently ranks fourth in the country for overall installed wind capacity with over 3.5 GW installed according to the American Wind Energy Association (AWEA).[45] According to the Energy Information Administration net generation from wind in Illinois increased 25 percent in 2013.[46]

Various categories of economic benefits are attributed to wind energy, including electricity price reductions, economic development, and local economies. Critics of wind energy point to factors that may offset some of the purported benefits of renewable energy resources, including government subsidization of the industry, reduced land values, wear and tear on local roads during the construction of turbines, future decommissioning costs, stranding of coal-fired and nuclear generation assets, and increasing spinning reserve requirements.

Impact on Electricity Prices

<u>General Price Impacts</u>

Illinois State University's Center for Renewable Energy concluded that because wind is both an inexhaustible energy source and is free from fuel price volatility, it can contribute to the nation's energy

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[42] 74 Fed. Reg. 66,495 (Dec. 15, 2009).

[43] Air Emissions Fact Sheet, U.S. Environmental Protection Agency http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html (accessed March 2012).

[44] Breath Taking: Premature Mortality due to Particulate Air Pollution in 239 American Cities, National Resources Defense Council, at 1 (May 1996).

[45] *State Wind Energy Statistics: Illinois*, published by the American Wind Energy Association (March 6, 2014).

[46] U.S. Energy Information Administration, "Electric Power Monthly", February 2014, Table 1.17.B.

security.[47] Wind power can lead to more stable electricity prices by diversifying supply portfolios and softening impacts from fuel price volatility. The U.S. Department of Energy also characterizes renewable energy as a resource for hedging against risks posed by electricity price volatility, particularly through the purchase of long-term, fixed-price supply contracts for renewable energy resources directly with developers or generators.[48] Using renewable energy can also reduce the risk of disruptions in fuel supplies, like natural gas, resulting from transportation difficulties or international conflict.[49] Likewise, wind power is not subject to the uncertainty surrounding future carbon taxes, unlike fossil fuel-fired power plants.[50]

Impacts on Locational Marginal Prices

Electricity purchased for either utilities or ARES in Illinois is sourced in competitive regional wholesale markets. Power that flows through the transmission grid and wholesale market is coordinated by PJM for ComEd customers and MISO for Ameren customers. PJM and MISO are two of the seven Regional Transmission Organizations (RTOs) responsible for reliable flows of energy. The RTOs ensure that the electrical system is always perfectly balanced between supply and demand, by dispatching generation (and load reduction under some circumstances) to meet the fluctuating load. Which power plants will be used at any time to serve load is generally determined through operation of wholesale electricity markets by the RTOs.

Wholesale electric energy prices are set for hourly periods based on bidding by available generators into the regional markets. Most analyses of the impact of renewable generation on electricity prices address these real-time Locational Marginal Prices (LMPs) and assume generator bids reflect variable costs. However, the IPA purchases power through block contracts in forward markets. Prices in those markets do not immediately incorporate changes in LMP fundamentals. Energy supply also requires the purchase of capacity credits, which guarantee the availability of power plants to reliably serve load under all circumstances. Because of their variable output, which is dependent on weather conditions, wind and solar resources have less impact on capacity prices than do dispatchable power plants. In PJM, the average capacity factor used to valuate new wind projects in the forward capacity market has been set at 13%, and solar is set at 38%.[51]

Increases in capacity bids from other generators would probably more than counteract any reduction in system capacity prices attributable to new wind plants. The fact that both wind and solar generators can offer their energy into wholesale electricity markets at a relatively low price has resulted in some concern that they might undercut and offset electricity offered into the markets by coal-fired and nuclear generators. Coal-fired and nuclear plants would then demand higher capacity prices to continue operation.

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[47] *Economic Impact: Wind Energy Development in Illinois*, Center for Renewable Energy, Illinois State University (June 2012) at 10.

[48] *Guide to Purchasing Green Power*, United States Department of Energy Office of Renewable Energy and Energy Efficiency, at 5. (March 2010).

[49] Id.

[50] Economic Impact: Wind Energy Development in Illinois at 10.

[51] PJM System Planning Department, *PJM Manual 21: Rules and Procedures for Determination of Generating Capability*, Revision 11, March 5, 2014, p. 19.

In both PJM and MISO, over the past six years, electric energy produced by coal-fired plants has accounted for a lower percentage of the total electricity generated, while nuclear generation has remained stable. In both markets the drop in coal-fired generation is largely attributable to lower natural gas prices. The most efficient gas-fired generation is becoming increasingly cost-competitive with the less efficient coal-fired generators. As shown in Figure III-1 and Figure III-2, the drop in coal-fired generation is more pronounced in PJM as there is more gas-fired generation installed there.[52]

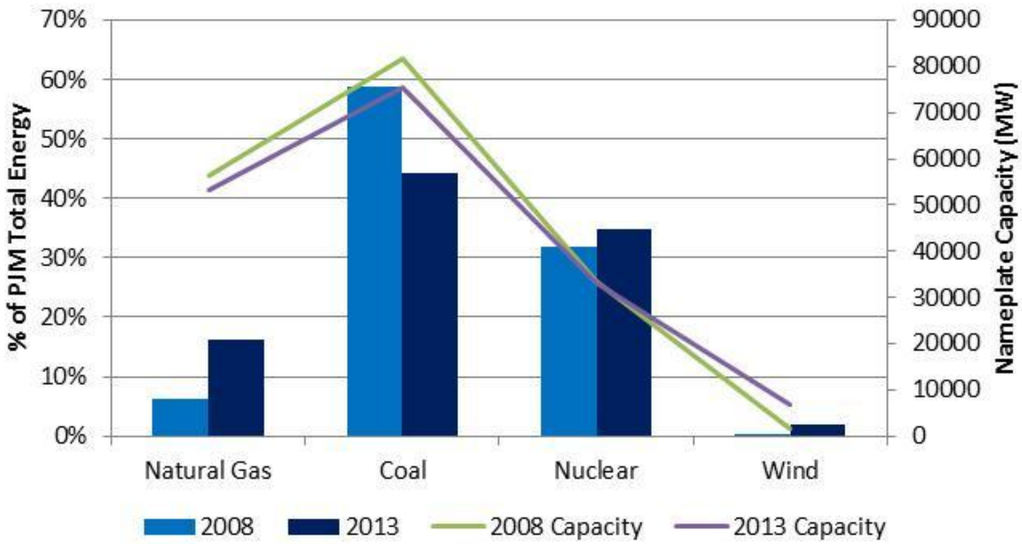

Figure III-1: 2008 and 2013 PJM Energy and Capacity by Fuel Type[53]

[52] The majority of the decrease in installed coal capacity in MISO resulted from the move of Duke Energy Ohio and Duke Energy Kentucky, with 4,657 MW of coal-fired generation, from MISO to PJM as of January 1, 2012. PJM experienced a 5,001 MW decrease in coal-fired generation between 2008 and 2012 and this decrease would have been even greater if not for the addition of the Duke Energy coal-fired generating capacity.

[53] Data Source: PJM State of the Market – 2013.

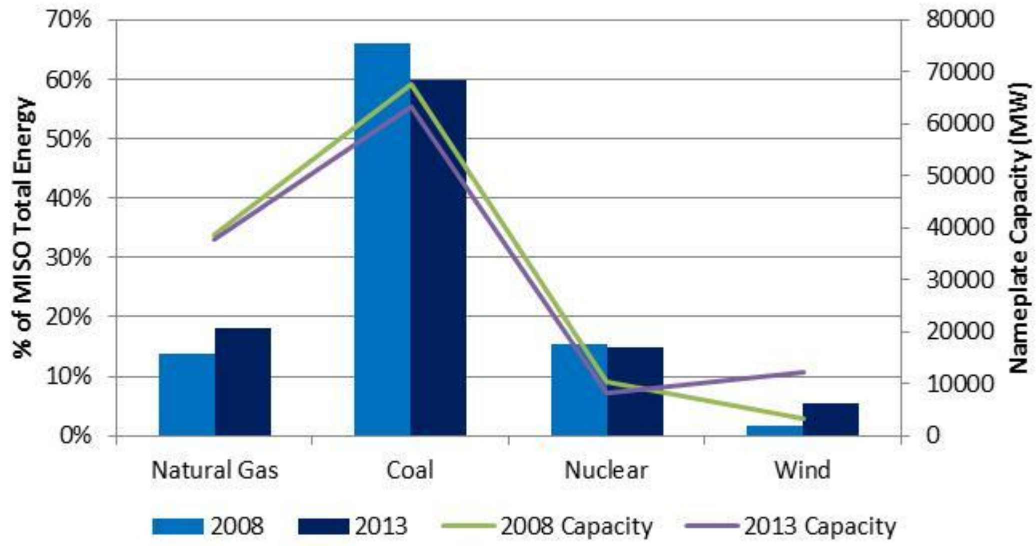

Figure III-2: 2008 and 2013 MISO Energy and Capacity by Fuel Type[54]

To date the impact of electricity supplied to the PJM market by wind generators has been negligible as it only accounted for 2% of the total market generation in 2013. In MISO wind generation reached 6% of total production in 2013.[55] The higher proportion of wind production in MISO is largely attributable to the fact that wind capacity represents a larger fraction of installed capacity in MISO than in PJM. Some of the increase in MISO wind generation is also due to the implementation of the Dispatchable Intermittent Resources designation that allows registered wind resources to participate in the real-time energy market.[56] Overall, increased wind generation has offset 42% of the decrease in MISO coal generation over the past six years.[57]

The market price effects of renewable resources added to the interconnected electric system can be estimated using market-modeling software. The IPA's previous procurement planning consultant, Adica, employed a proprietary market model[58] capable of modeling the entire Eastern Interconnection[59] using data at the nodal level for both load and generation. For the 2012 edition of this Report,[60] the IPA commissioned the consultant to run the model with and without Illinois renewable generation in order to test the effect on overall LMPs for calendar year 2011. The model results indicated a reduction of several percent in average

[54] Data Source: MISO 2013 Summer Resource Assessment (capacity data) and Energy Velocity (energy data).

[55] Source: Energy Velocity.

[56] MISO 2012 Winter Assessment Report.

[57] Source: Energy Velocity.

[58] MarSi is a software tool developed by GEMS for electricity market simulations which uses generator data, transmission network data, and hourly load data to model the effects of changes in fuel prices, carbon costs, wind and solar penetration, load growth and load growth rate, and addition/decommissioning/planned outages of generating units and transmission lines.

[59] The Eastern Interconnection includes MISO and PJM.

[60] Available at http://www2.illinois.gov/ipa/Pages/IPA_Reports.aspx.

LMPs, based on the impact of all Illinois wind generation (not just the amount under contract to IPA). As noted above, LMP reductions are not necessarily directly or immediately reflected in the prices the IPA pays for energy.

Economic Development

Illinois State University's Center for Renewable Energy modeled the economic impact of wind energy upon Illinois' economy by entering project specific information into the National Renewable Energy Laboratory's (NREL) Jobs and Economic Development Impact (JEDI) model to estimate the income, economic activity, and number of job opportunities accruing to the state from the project.[61] The report estimated that the development of the 23 largest Illinois wind farms installed at the time of the analysis, accounting for 3,335 MW of nameplate capacity, was responsible for 19,047 full-time equivalent (FTE) jobs in Illinois during construction and 814 permanent jobs, and will generate a total economic benefit of $5.98 billion[62] during the construction and 25-year operational lives of the projects.

The report found that wind power leads to the creation of temporary and permanent jobs requiring highly skilled workers in the fields of construction, management, and engineering.[63] Construction phase jobs typically last anywhere from 6 months to over a year, while operational jobs, including operations and maintenance positions, last the life of the wind farm, typically 20-30 years.[64]

The jobs and economic benefit estimated in the report included "turbine and supply chain impacts" or "indirect impacts."[65] Indirect impacts occurred both in the construction and the operation of wind turbines, and included construction spending on materials and wind farm equipment and other purchases of goods and offsite services and "expenditures related to on-site labor, materials, and services needed to operate the wind farms (e.g., vehicles, site maintenance, fees, permits, licenses, utilities, insurance, fuel, tools and supplies, replacement parts/equipment); the supply chain of inputs required to produce these goods and services; and project revenues that flow to the local economy in the form of land lease revenue, property tax revenue, and revenue to equity investors."[66] The estimate also included local spending by employees working directly or indirectly on the wind farm project who receive their paychecks and then spend money in the community.[67]

The analysis also concluded that local wind turbines raise the property tax base of a county, which can create "a new revenue source for education, fire departments, and other local government services,"[68] since local governments can receive significant amounts of revenue from permitting fees.[69] Benefits to landowners identified included revenue from leasing their land, which the report found was "usually greater

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[61] Economic Impact: Wind Energy Development in Illinois at 20.

[62] Economic Impact: Wind Energy Development in Illinois at 7.

[63] Economic Impact: Wind Energy Development in Illinois at 26.

[64] Id.

[65] Economic Impact: Wind Energy Development in Illinois at 21.

[66] *Id*. at 22.

[67] *Id*. at 23.

[68] *Id*. at 11.

[69] *Id*. at 18.

than that from ranching or farming and it does not require any work from the landowners."[70] There may be some local concerns such as wear and tear on roads during construction, unfunded decommissioning cost liability, and possibly lowered land values that should be considered when evaluating any specific project's impacts.

Related statistics have been published by other parties. According to the AWEA, wind power supports 6,001-7,000 jobs in Illinois.[71] This apparently includes manufacturing jobs, which may be supported by wind generation located outside Illinois. The Clean Energy Trust ("CET") in partnership with Environmental Entrepreneurs ("E2"), the Environmental Law and Policy Center ("ELPC") and the Natural Resources Defense Council ("NRDC") in a recent report states that 20,123 Illinois workers are in the renewable energy sector.[72]

Impact of Economic Incentives for Wind Energy

In the last few years, the economics of renewable energy have been influenced by state and federal tax credits and other taxpayer supported incentives. It is unknown whether these incentives will be modified or will remain available. The following state tax incentives impact the benefits derived from renewable energy resources:

- An Investment Tax Credit entitles Illinois developers to a 0.5% income tax credit for investments in qualified property, which may include building, structures, and other tangible property.[73]
- A Jobs Tax Credit entitles Illinois employers to a $500 tax credit for hiring individuals certified as economically disadvantaged.
- A Sales-and-Use Tax Exemption for Building Materials grants Illinois businesses full exemption from sales-and-use tax without having to apply for enterprise zone status.[74]
- Property Tax Valuation of Wind Turbines: The wind energy property assessment division of the Illinois Property Tax Code specifies wind energy devices larger than 500 kilowatts (kW) that produce power for commercial sale be valued at $360,000 per megawatt (MW) of capacity and annually adjusted for inflation according to the United States Consumer Price Index.[75] The depreciation allowance may not exceed 70%. Current law allows this valuation methodology to be

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[70] *Id*. at 18.

[71] State Wind Energy Statistics: Illinois.

[72] Clean Energy Trust, *Clean Jobs Illinois: An In-Depth Look at Clean Energy Employment in Illinois*, March, 2014, at 11 and 15.

[73] Economic Impact: Wind Energy Development in Illinois at 15.

[74] Pub. Act 96-28 (eff. July 1, 2009) amended the Illinois Enterprise Zone Act, to provide that businesses that intend to establish a new wind power facility in Illinois may be considered "high impact businesses" allowing them to claim a full exemption from sales-and-use tax without having to apply for enterprise zone status. *See* Economic Impact: Wind Energy Development in Illinois at 16.

[75] 35 ILCS 200/10-605.

used until the end of 2016. This provides greater certainty for all stakeholders in wind energy developments.[76]

At the federal level, the American Taxpayer Relief Act of 2012 modified and extended tax credits and other incentives for wind energy. The production tax credit (PTC) for wind energy, created under the Energy Policy Act of 1992, provides an income tax credit of 2.3 cents per kilowatt-hour for the production of electricity from utility-scale turbines for the first 10 years of electricity production. The PTC, which was previously renewed by the American Recovery and Reinvestment Act of 2009 (ARRA), expired at the end of 2013 and has not yet been extended. Since its inception, the PTC has been allowed to lapse four times: in 2000, 2002, 2004, and now 2013. Although in the first three cases the credit was extended retroactively, the uncertainty in the market resulted in decreases in new capacity additions ranging from 73% to 93%[77] of the previous year's installed capacity.

The American Taxpayer Relief Act of 2012 (ATRA) extended "bonus depreciation" for both wind and solar generation projects first established by the Economic Stimulus Act of 2008. Prior to the inception of bonus depreciation, wind and solar project developers were allowed to recover investments through depreciation deductions over a five-year period. Under the bonus depreciation guidelines, the first-year deduction for property acquired and placed in service between September 8, 2010 and the end of 2011 is 100% of the adjusted basis, and for property placed in service in 2012 and 2013 the allowable first-year deductions is 50% of the adjusted basis with the remaining 50% depreciated over the ordinary MACRS depreciation schedule.

The investment tax credit (ITC) for renewable energy, which allows certain generation facilities to take a one-time credit in the year in which they are placed in service, was first introduced in 1978 and has been modified and extended multiple times since the mid-80s. Solar energy technology has qualified for the ITC throughout the history of the program, and in 1992, the 10% ITC was made permanent for solar. In 2005, legislation temporarily increased the solar ITC to 30% and subsequent legislation extended the 30% rate through the end of 2016, at which time it will revert to 10%.

Through Section 1603 of the ARRA, wind project developers were given the option of choosing to receive a 30% ITC in lieu of the PTC for new developments placed in service prior to the end of 2012. The ATRA extended this option through the end of 2013 and modified it such that wind projects only need to have started construction to qualify.

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[76] Economic Impact: Wind Energy Development in Illinois at 16.

[77] Production Tax Credit Fact Sheet, American Wind Energy Association (April 2011).

C. Rate Impacts on Eligible Retail Customers

"[T]he Agency shall prepare a public report … that shall include … an analysis of the rate impacts associated with the … Agency's procurement of renewable resources, including … any long-term contracts, on the eligible retail customers of electric utilities. The analysis shall include the Agency's estimate of the total dollar impact that the Agency's procurement of renewable resources had has on the annual electricity bills of the customer classes that comprise each eligible retail customer class."[78]

The IPA asked Ameren and ComEd to provide their rate spreadsheets by customer class for each of the three delivery years examined. The spreadsheets break out, by delivery year, the additional amounts reflected in the supply charge attributable to renewable resource delivery. These spreadsheets provide the rate impact associated with the Agency's procurement of renewable resources. When multiplied by the overall billing determinants, the values from the spreadsheets provide the total dollar impact on the annual electricity bills of each customer class. Results for each electric utility and corresponding customer class are presented for ComEd in Table III-6 and Table III-7 and for Ameren in Table III-8 and Table III-9. Note that these rate impacts are only for eligible retail customers who are the customers who take energy supply service from the utility. Customers who buy their electricity from an Alternative Retail Electric Supplier are not included in these spreadsheets.

[78] 20 ILCS 3855/1-75(c)(5).

1. ComEd

Customer Class	Description	2009 Plan Year	2010 Plan Year	2011 Plan Year	2012 Plan Year	2013 Plan Year (Through January 2014)
Single Family No Electric Space Heat	Revenue/kWh	$0.118	$0.132	$0.132	$0.128	$0.107
	REC/kWh	$0.000768	$0.000258	$0.000064	$0.001152	$0.001800
	Ratio (REC/Revenue)[79]	0.65%	0.20%	0.05%	0.90%	1.68%
Multi Family No Electric Space Heat	Revenue/kWh	$0.134	$0.148	$0.145	$0.141	$0.122
	REC/kWh	$0.000768	$0.000258	$0.000063	$0.001151	$0.001900
	Ratio (REC/Revenue)	0.57%	0.17%	0.04%	0.81%	1.55%
Single Family With Electric Space Heat	Revenue/kWh	$0.081	$0.090	$0.085	$0.093	$0.085
	REC/kWh	$0.000498	$0.000170	$0.000042	$0.000554	$0.002000
	Ratio (REC/Revenue)	0.61%	0.19%	0.05%	0.59%	2.36%
Multi Family With Electric Space Heat	Revenue/kWh	$0.089	$0.099	$0.093	$0.100	$0.091
	REC/kWh	$0.000499	$0.000170	$0.000043	$0.000552	$0.001900
	Ratio (REC/Revenue)	0.56%	0.17%	0.05%	0.55%	2.09%
Watt-hour	Revenue/kWh	$0.132	$0.145	$0.150	$0.151	$0.134
	REC/kWh	$0.000780	$0.000270	$0.000060	$0.001240	$0.002000
	Ratio (REC/Revenue)	0.59%	0.19%	0.04%	0.82%	1.49%
Small Load (< 100 kW)	Revenue/kWh	$0.101	$0.114	$0.113	$0.112	$0.095
	REC/kWh	$0.000770	$0.000270	$0.000060	$0.001210	$0.001900
	Ratio (REC/Revenue)	0.76%	0.24%	0.05%	1.08%	2.01%

Table III-6: ComEd Rate Impact - Calculated Bill Impacts by RECs[80]

[79] This value represents the amount that RECs cost each customer of that delivery year class as a percentage of the amount paid for total "annual electricity bills," including taxes. Thus, a Rate Impact of 0.69% means that 0.69% of the total electricity bill of a customer of that class in that delivery year was spent on contracts for renewable energy resources and credits.

[80] Overall bill (e.g. Revenue/kWh) includes fixed supply charges, PJM services charges, delivery services charges (customer charge, standard metering service charges, and distribution facilities charges, and Illinois Electricity Distribution Tax charge), other environmental cost recovery and energy efficiency & demand adjustments, franchise cost additions, and municipal and state taxes.

Customer Class	Description	2009 Plan Year	2010 Plan Year	2011 Plan Year	2012 Plan Year	2013 Plan Year (Through January)
Single Family No Electric Space Heat	Usage (kWh)	24,195,356,771	25,557,124,031	19,465,098,302	12,843,203,500	4,473,893,731
	Dollar Impact ($)	$18,582,034	$6,593,738	$1,245,766	$14,795,370	$8,053,009
Multi Family No Electric Space Heat	Usage (kWh)	4,837,665,365	5,384,174,419	4,178,671,736	3,041,118,982	846,413,283
	Dollar Impact ($)	$3,715,327	$1,389,117	$263,256	$3,500,328	$1,608,185
Single Family With Electric Space Heat	Usage (kWh)	881,222,892	506,129,412	645,304,684	546,220,195	233,922,702
	Dollar Impact ($)	$438,849	$86,042	$27,103	$302,606	$467,845
Multi Family With Electric Space Heat	Usage (kWh)	1,860,212,425	984,758,824	1,361,870,329	991,185,128	352,736,528
	Dollar Impact ($)	$928,246	$167,409	$58,560	$547,134	$670,199
Watt-hour	Usage (kWh)	588,208,974	578,444,444	392,413,102	210,947,790	68,776,860
	Dollar Impact ($)	$458,803	$156,180	$23,545	$261,575	$137,554
Small Load (< 100 kW)	Usage (kWh)	9,766,981,818	8,912,892,593	6,005,560,303	4,701,423,060	2,736,667,833
	Dollar Impact ($)	$7,520,576	$2,406,481	$360,334	$5,688,722	$5,199,669

Table III-7: ComEd Total Dollar Impact[81]

[81] For Plan Years 2011, 2012 and 2013, the Usage values are from the "switching statistics" reported by the Illinois Commerce Commission (http://www.icc.illinois.gov/electricity/switchingstatistics.aspx), excluding the usage of customers taking supply service from a Retail Electric Supplier (RES). Dollar Impact values for those Plan Years were calculated by multiplying the Usage by the REC/kWh reported in Table III-6. For Plan Years 2009 and 2010, the "switching statistics" did not provide this amount of customer class detail; Dollar Impacts values for those years in Table III-7 are taken from Figure 28 in the 2012 Report and Usage was calculated by dividing the reported Dollar Impact by the REC/kWh reported in Table III-6.

2. Ameren

Customer Class	Description	2009 Plan Year	2010 Plan Year	2011 Plan Year	2012 Plan Year	2013 Plan Year (Through January)
Residential Service	Revenue/kWh	$0.104	$0.107	$0.108	$0.104	$0.089
	REC/kWh	$0.000645	$0.000211	$0.000058	$0.000669	$0.0014661
	Ratio (REC/Revenue)[82]	0.62%	0.20%	0.05%	0.65%	1.64%
Small General Service	Revenue/kWh	$0.111	$0.108	$0.107	$0.102	$0.087
	REC/kWh	$0.000645	$0.000211	$0.000058	$0.000669	$0.0014661
	Ratio (REC/Revenue)	0.58%	0.20%	0.05%	0.66%	1.68%
General Service	Revenue/kWh	$0.086	$0.084	$0.083	$0.075	$0.061
	REC/kWh	$0.000645	$0.000211	$0.000058	$0.000669	$0.0014661
	Ratio (REC/Revenue)	0.75%	0.25%	0.07%	0.89%	2.40%

Table III-8: Ameren Rate Impacts[83]

Customer Class	Description	2009 Plan Year	2010 Plan Year	2011 Plan Year	2012 Plan Year	2013 Plan Year (Through January)
Residential Service	Usage (kWh)	11,113,952,386	12,099,965,649	11,038,029,446	8,263,759,490	3,112,369,480
	Dollar Impact ($)	$7,168,499	$2,553,093	$644,621	$5,525,976	$4,563,045
Small General Service	Usage (kWh)	3,615,924,697	3,026,300,756	2,544,215,445	2,063,439,107	1,242,771,645
	Dollar Impact ($)	$2,332,271	$638,549	$148,582	$1,379,822	$1,822,028
General Service	Usage (kWh)	1,240,657,248	623,518,977	443,840,561	304,704,282	163,061,596
	Dollar Impact ($)	$800,224	$131,563	$25,920	$203,756	$239,065

Table III-9: Ameren Total Dollar Impact

D. Rate Impacts on Customers of Alternative Retail Electric Suppliers

"The Agency's report shall … analyze how the operation of the alternative compliance payment mechanism, any long-term contracts, or other aspects of the applicable renewable portfolio standards impacts the rates of customers of alternative retail electric suppliers."[84]

An ARES may satisfy its RPS requirement entirely through Alternative Compliance Payments (ACP) or through a combination of an ACP payment and procurement of renewable resources. An ARES must meet at least 50% of its RPS requirement using the ACP mechanism.[85] The law allows ARES to meet 100% of the RPS with the ACP mechanism, though it appears that most ARES currently choose to use the

[82] This value equals the REC/kWh value for the delivery year class divided by the total revenue per kilowatt-hour of the corresponding delivery year class. The REC/kWh value is equal to the cost of renewable resources in the delivery year, calculated based on the ACP computed by the ICC, divided by the forecasted load of eligible customers during the same period. *See* 220 ILCS 5/16 115D(d)(1). Thus, a Rate Impact of 0.70% means that 0.7% of the forecasted revenue from that class in the given delivery year was spent on contracts for renewable energy resources and credits.

[83] A single company-wide rate is reported for Ameren, as was the case in the 2013 Report. This differs from the 2012 report where separate rates were reported across 3 rate zones and reflects the fact that the merged companies that comprise Ameren are now fully integrated.

[84] 20 ILCS 3855/1-75(c)(5).

[85] 220 ILCS 5/16-115D(d).

ACP for the minimum 50% of the required RPS. This behavior is to be expected as long as market prices for REC products which satisfy the RPS requirement for an ARES produce a lower cost alternative to using ACP for 100% of the RPS compliance.[86] This Report has estimated the ACP payment based on the actual published ACP rate and the estimated load of ARES customers.

Delivery Year	ComEd Usage Forecast[87] (kWh)	ComEd ACP Rate (¢/kWh)	Ameren Usage Forecast (kWh)	Ameren ACP Rate (¢/kWh)
June 2009- May 2010	39,469,952,000	0.0764	17,700,274,000	0.0645
June 2010- May 2011	35,993,039,000	0.0256	16,525,235,000	0.0211
June 2011- May 2012	35,335,934,000	0.00568	15,065,960,000	0.00584
June 2012- May 2013	19,695,906,000	0.09724	11,125,884,000	0.06687
June 2013- May 2014[88]	10,557,106,000	0.15923 (estimated)	5,405,499,000	0.14661 (estimated)

Table III-10: ACP Rates[89]

Assuming an ARES uses the ACP to meet half its RPS requirement and passes through the costs of the ACP to all its volume sold, the estimated rate impact on ARES customers would be half the values shown in Table III-10 above. That is, for an ARES customer in Ameren territory, the ARES rate impact in delivery year June 2009 to May 2010 would be 0.03225 cents per kilowatt-hour for the ACP portion of that ARES's compliance.

Because ACPs are based on the utilities' average cost of REC procurement, if ARES were to pay approximately the same amount for renewable resources they directly procure as the IPA, the bill impact of

[86] ARES are required to procure renewable energy or credits equal to at least 8% of total sales. The estimated ACP Rate for ComEd for the June 2013 through May 2014 delivery period is 0.15923 cents/kWh sold, which is equivalent to the cost of buying RECs equal to 8% of sales for 1.99 cents/kWh. That price target significantly exceeds the market price of RECs, based on both the IPA's own procurement (0.926 cents/kWh per Figure 1) and estimates published by the US Department of Energy (http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5).

[87] "Usage" in this table is the forecasted usage of utility supply customers only (excludes ARES customers).

[88] Because the delivery year has not yet been completed, an actual ACP rate cannot be provided and instead the estimated ACP rate for delivery year 2013- provided in the Illinois Commerce Commission Notice Concerning Alternative Compliance Payments on 5/13/2013- has been used.

[89] Sources are as follows: Illinois Commerce Commission:

2009 DY – 2011 DY: http://www.icc.illinois.gov/electricity/rpscompliancepaymentnotices.aspx - ACP Rate History as of 2013-05-13.pdf.

2012 DY: http://www.icc.illinois.gov/electricity/rpscompliancepaymentnotices.aspx - Notice of 2012-2013 Actual ACP Rate as of 2013-07-01.pdf.

2013 DY: http://www.icc.illinois.gov/electricity/rpscompliancepaymentnotices.aspx - Notice of 2013-2014 Estimated ACP Rate as of 2013-05-13.pdf.

renewable procurement on ARES and utility customers would be similar in dollar amount. The percentage impact on an ARES, is shown in Table III-11. However, if ARES procure different or cheaper products (for instance, only purchasing short-term RECs rather than entering into long-term PPAs), ARES costs are likely to be less in the short run.

Utility Territory	**ACP Rate (¢/kWh) (estimated) – From Table III-10**	**Representative ARES Price (¢/kWh)[90]**	**Maximum Rate Impact on ARES Customers Assuming 100% ACP (estimated)**
ComEd	0.15923	7.18	2.22%
Ameren (Zone 1)	0.14661	5.51	2.66%
Ameren (Zone 2)	0.14661	5.52	2.66%
Ameren (Zone 3)	0.14661	5.51	2.66%

Table III-11: RPS Compliance - Comparative Rate Impact on ARES Customers

The ICC's estimated ACP Rates for the June 2013 through May 2014 Plan Year are shown in Table III-10 above. These estimates include the effect of the 2010 LTPPAs and reduced energy forecast (resulting primarily from migration form utility supply service). The rate impact is a high-end estimate that assumes that an ARES complied with the RPS through 100% ACP payments rather than the minimum 50% payment and purchases of RECs that appears to be more typical of most ARES. Price information on ARES direct purchases of RECs is not publically available so an exact calculation of typical or average rate impacts on ARES customers is not possible.

[90] Representative ARES prices are based on offers found on the Plug in Illinois website for 12-month fixed price non-green energy contracts as of 3/14/14. Any monthly fees included with the offers were converted to cents/kWh based on a usage rate of 1000 kWh/month. http://www.pluginillinois.org/OffersBegin.aspx. Note that some plans may contain early terminations fees which are not included in the calculation of representative prices.

IV. Solar And Distributed Power in Other States

A. Introduction

Several incentive mechanisms provided by local and Federal governments have resulted in increased penetration of renewable energy resources into the US energy mix. Renewable Portfolio Standards (RPS), designed to encourage electricity generation from renewable resources, are one of such mechanisms. Currently more than 30 states enforce RPS or other mandated renewable capacity generation. Many of these states also have a solar carve-out program within their RPS policies. Solar carve-out programs are designed to ensure that part of the renewable electricity comes from solar energy. Table IV-1 shows the RPS standard and solar targets for several states, including specific examples discussed in this Section and Illinois for comparison.

State	RPS Target	RPS Due Date	Solar Target	Solar Due Date	Estimated Amount of Annual Solar Energy by Due Date*
New Jersey	22.5%	2021	4.1% of Electricity	2028	4,024 GWh
Pennsylvania	18%	2021	0.5% of Electricity	2021	682 GWh
Massachusetts	15%	2020	Annually Calculated Formula	2014	460 GWh
Maryland	20%	2022	2% of Electricity	2021	1,638 GWh
Ohio	12.5%	2024	0.5% of Electricity	2024	997 GWh
Illinois	25%	2026	6% of Renewables (1.5% of Electricity)	2026	N/A

* Sources: http://www.srectrade.com, http://www.dsireusa.org

Table IV-1 Solar Capacity Targets by Selected States

According to Solar Energy Industries Association, 2013 was a record year in terms of solar capacity installations in the US – "there were 4,751 MW of new photovoltaic (PV) capacity installed in 2013, representing a 41% increase in deployment over installation levels in 2012. Solar accounted for 29% of all new electricity generation capacity added in 2013, up from just 10 percent on 2012 [91]." Table IV-2 shows the installed solar generation for the states listed in Table IV-1.

[91] http://www.seia.org/research-resources/solar-industry-data.

State	Capacity Constructed	Reporting Date	Data Source*
New Jersey	1,204 MW	February 2014	SNL
	977 MW	Unknown	www.openpv.nrel.gov
Pennsylvania	126 MW	Unknown	www.openpv.nrel.gov
Massachusetts	415 MW	February 2014	www.mass.gov
	245 MW	Unknown	www.openpv.nrel.gov
Maryland	105 MW	Unknown	www.openpv.nrel.gov
Ohio	30 MW	Unknown	www.openpv.nrel.gov
Illinois	16 MW	Unknown	www.openpv.nrel.gov

* Data reported on www.openpv.nrel.gov is likely to be out-of-date and underestimated.

Table IV-2: Installed Capacity to Date

It is also worth noting the average solar radiation measurements to illustrate the solar potential differences across geographical locations. As Table IV-3 shows, there are no significant variations in solar radiation across the states in consideration. Hawaii is added to represent a location with high solar radiation as compared to the others.

State, City	Solar Radiation ($kWh/m^2/day$)
New Jersey, Atlantic City	4.6
Pennsylvania, Allentown	4.4
Massachusetts, Boston	4.6
Maryland, Baltimore	4.6
Ohio, Akron	4.1
Illinois, Chicago	4.4
Hawaii, Honolulu	5.7

Table IV-3: Solar Radiation Measurements[92], Averaged Over 30 Years Between 1961-1990.

The following Sections summarize the solar and distributed generation programs of New Jersey, Pennsylvania and Massachusetts. Section IV.B summarizes the economic and regulatory environment for each state, including a short summary on estimated costs and benefits of distributed generation for certain jurisdictions. Section IV.C provides data and analysis on the Solar Renewable Energy Credit (SREC) markets created within these states.

[92] Data source is http://rredc.nrel.gov/solar/pubs/redbook. Average solar radiation for flat-plate collectors facing south at latitude tilt is reported. Uncertainty is ±9%.

B. Economic and Regulatory Environment

1. New Jersey

The state of New Jersey employs 5,700 people in the solar industry, the ninth highest per capita in the U.S.[93] Its RPS is one of the most aggressive standards in the country; requiring each electricity supplier/provider serving retail customers to procure 22.5% of the electricity it sells from renewable energy resources by May 2021. Despite its low solar resources, according to a National Renewable Energy Laboratory database it has the third greatest number of photovoltaic installations among the states, and second highest installed photovoltaic capacity.[94]

The state mandate establishes two main "classes" of renewable energy resources, "Class I" and "Class II". Solar energy falls under Class I. In addition, there is a separate "Solar Carve-Out" program that sets annual solar electric targets. New Jersey's initial RPS was originally adopted in 2009. In July 2012, the state strengthened its RPS after enacting S.B. 1925, and substantially revised its solar carve-out program to account for fast solar development. Figure IV-1 shows New Jerseys' yearly Solar RPS (SRPS) requirements.

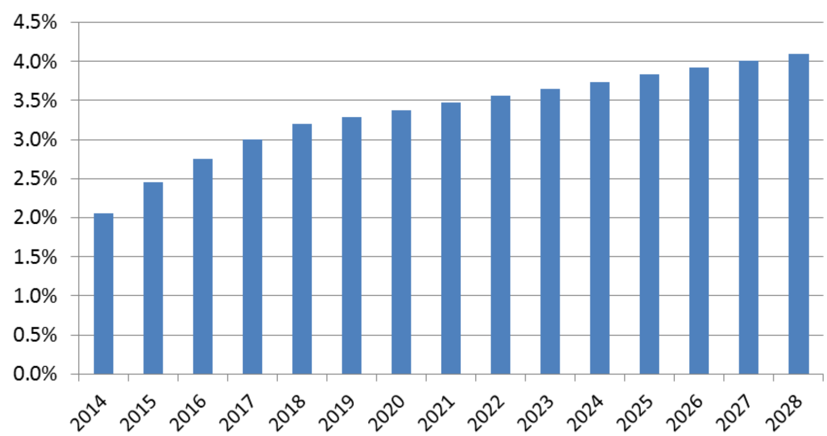

Figure IV-1: NJ Yearly SRPS Requirements as a Percentage of Total Electricity Sold

Each electricity supplier in New Jersey is obligated to file an annual report to the New Jersey Board of Public Utilities (BPU) to demonstrate that the requirements of the RPS of the preceding year have been met. Failure to meet RPS targets may result in suspension of the supplier's license, financial penalties, disallowance of recovery of costs in rates, and/or prohibition on accepting new customers. Entities responsible for meeting SRPS requirements can purchase Solar Renewable Energy Credits (SRECs) in the market from the solar facilities. The qualification life for solar facilities is set to 15 years – solar facilities are eligible to produce SRECs during this period only. More details in SRECs can be found in Section IV.C.1.

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[93] http://www.solarpowerworldonline.com/2013/10/solar-power-world-top-250-top-solar-contractors-new-jersey/.

[94] http://www.openpv.nrel.gov, observed on March 17, 2014. Thanks to recently completed utility-scale plants, Arizona is now second in capacity (cf. http://www.marketwatch.com/story/the-united-states-of-solar-the-top-5-in-solar-power-2014-03-18, as observed on March 19, 2014).

Net Metering

Net metering applies to all residential, commercial and industrial customers of the state's investor-owned utilities and energy suppliers, and to certain competitive municipal-owned utilities and electric cooperatives.

S.B. 2936 (Jan 2008) allows utilities to recover the costs of "any new net meters, upgraded net meters, system reinforcements and upgrades, and interconnection costs" either through their regulated rates or from net-metered customers.

Net excess generation (NEG) is generally credited to customer's next bill at retail rate, but there are also options for compensation on a real-time basis according to the PJM power pool real-time locational marginal pricing rate, adjusted for losses by the respective zone in the PJM. Additionally, customer-generator may enter into a bilateral agreement with their electric supplier or service provider for the sale and purchase of NEG.

There is no specific limit for eligible system size, but the system must be "connected to the distribution system". The term "connected to the distribution system" is defined as:

- Net metered facilities.
- Facilities that meet the definition of "on-site generation".
- Facilities eligible for aggregated net metering.
- Facilities owned or operated by a public utility approved by the BPU.
- Facilities connected to the distribution system at 69 kV or less and approved by the BPU.
- Facilities certified by the BPU and Department of Environmental Protection (EDP) as being located on a brownfield, and area of historic fill or a closed landfill.

Utilities are required to report net metering enrollment reports to the BPU twice annually, one covering January - June and other covering July - December. The reports must contain:

1. Information detailing estimated customer generation supplied to the distribution grid.
2. Estimated grid electricity supplied to net metered customers.
3. The number of customers that received payments for annual NEG.
4. The total dollar amount paid to net metering customers for annual NEG by month.

2. Pennsylvania

Pennsylvania's Alternative Energy Portfolio Standard (AEPS) mandates that 18% of power should be procured from renewable and alternative sources, of which 0.5% should be from solar power, by 2021. Figure IV-2 shows Pennsylvania's SRPS requirements.

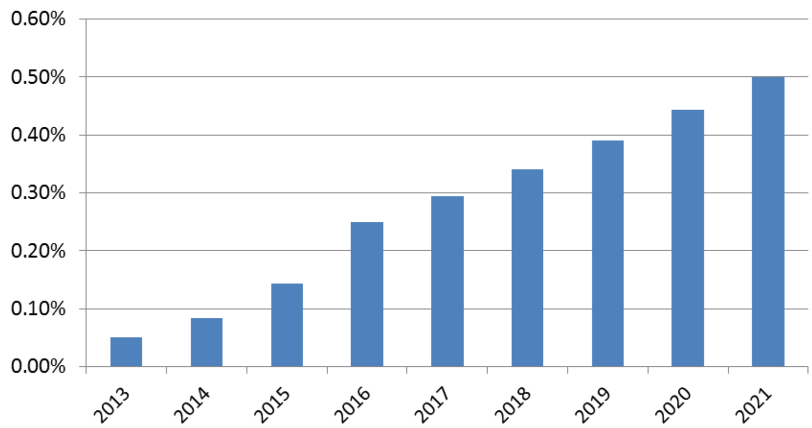

Figure IV-2: PA SRPS Requirements as a Percentage of Total Electricity Sold

Net Metering

Distributed generation related legislation in Pennsylvania goes back to 2006 when net-metering rules and interconnection standards for net-metered systems were adopted. These rules and standards apply to the following sectors: commercial, industrial, residential, non-profit, schools, local government, state government, federal government, agricultural, and institutional. Investor-owned utilities must provide net metering at non-discriminatory rates, and may not charge net-metered customers any fees or other charges that do not apply to non-net-metered customers.[95] Furthermore, utilities may not require customers to install any additional equipment or carry liability insurance.

System capacity limit for net metering is 5 MW for micro-grid and emergency systems; 3 MW for non-residential; and 50 kW for residential systems.

NEG is credited to customer's next bill at retail rate reconciled annually. The retail rate is based on the generation and transmission components, but does not include the distribution component.

3. Massachusetts

Massachusetts mandates investor-owned utilities[96] and retail suppliers to meet the 15% renewable energy target by 2020 within its RPS program.[97] Starting in 2010, retail suppliers must provide a portion of the renewable energy from interconnected solar facilities. Qualifying solar facilities, known as "Solar Carve-Out Renewable Generation Units", must have a capacity value of 6 MW or less. The Solar Carve-Out Minimum Standard is calculated based on a formula developed by the Department of Energy Resources (DOER) considering factors such as previous year's compliance obligation, amount of SRECs generated in

[95] Municipal-owned utilities are not required to offer net metering to its customers.

[96] Municipal-owned utilities are not required, but they may choose to offer net metering voluntarily.

[97] 15% target applies to new resources only (Class I). For old resources (Class II) the target is 7.1% in 2009 and thereafter (3.6% renewables and 3.5% waste-to-energy).

the last two years, banked volume, auction volume and load.[98] The minimum standard for 2014 has been calculated as 0.9481%.[99] Figure IV-3 shows the calculated Massachusetts SRPS requirements between 2010 and 2014.

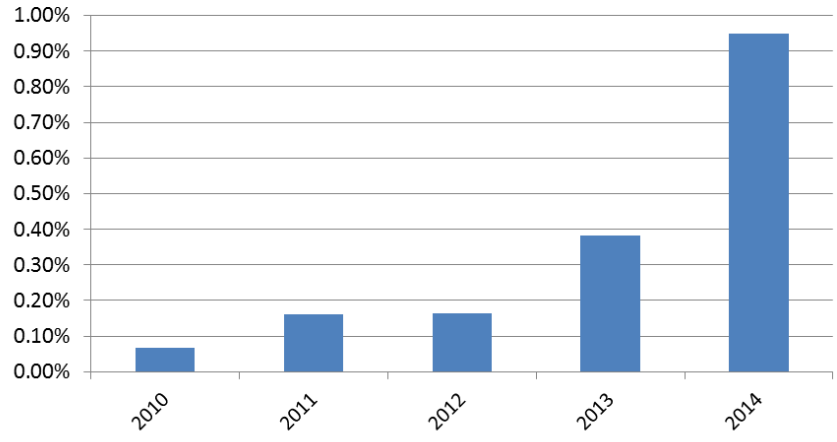

Figure IV-3: MA SRPS Requirements

Net Metering

Net metering legislation dates back to 1982 in Massachusetts. The original legislation gave net metering authorization to renewable energy systems and combined-heat-and-power facilities with a generating capacity up to 30 kW by the Massachusetts Department of Public Utilities (DPU). Currently, net metering applies to all of the following sectors: commercial, industrial, residential, nonprofit, schools, local government, state government, government, agricultural, and institutional. The maximum capacity limit is 10 MW for net metering by a municipality or other governmental entity and 60 kW for all other Class I systems, which include solar facilities. Starting from 1997, customers were given the permit to get credit for NEG, valued at the average monthly market price of generation. The treatment of customer NEG depends on the facility and customer type, but in all cases, it is monetized and credits are calculated based on the excess electricity produced.

There is a capacity cap on net-metered generation – private entities, municipalities or government entities cannot exceed 3% of the distribution company’s peak load.[100]

C. Solar Renewable Energy Credit (SREC) Markets

Solar Renewable Energy Credits exist in states that have solar carve-out programs within their RPS legislation. Similar to the Renewable Energy Credits (RECs) that are attributable to other renewable

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[98] The details can be found at http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/solar/rps-solar-carve-out/current-status-of-the-rps-solar-carve-out-program.html.

[99] If the Solar Credit Clearinghouse Auction clears in the first or second round, the minimum standard will be 0.8688%.

[100] Because net metering has an aggregate capacity cap, as described above, the DPU passed a "System of Assurance of Net Metering Eligibility" in May 2012 for customers of investor-owned utilities. This will serve as a net metering queue and help potential net metering customers know in advance if their system will be allowed to net meter or not.

electricity sources, SRECs are produced each time a solar facility produces one MWh of electricity, and they can be traded across market participants within a market region. In some cases, SREC trading is restricted within the state; in others it includes other jurisdictions within a regional transmission organization's territory, such as PJM or MISO. Solar facilities must be certified by states to produce SRECs. The value of an SREC is determined based on the supply and demand conditions of the market it is traded in.

In each state with an SREC market, there is an alternative compliance mechanism known as Solar Alternative Compliance Payment (SACP) for those electricity suppliers that cannot meet the SRPS requirement either through their own distributed generation facilities or through purchasing SRECs at the end of a compliance period. The payment amounts are set by state legislations and vary across states, but usually decline every year to account for increased solar capacity penetration in future years. The expectation is that the solar markets will eventually mature and there will be sufficient solar capacity installed to meet the state's overall SRPS requirements without the need for SRECs or SACPs.

1. New Jersey

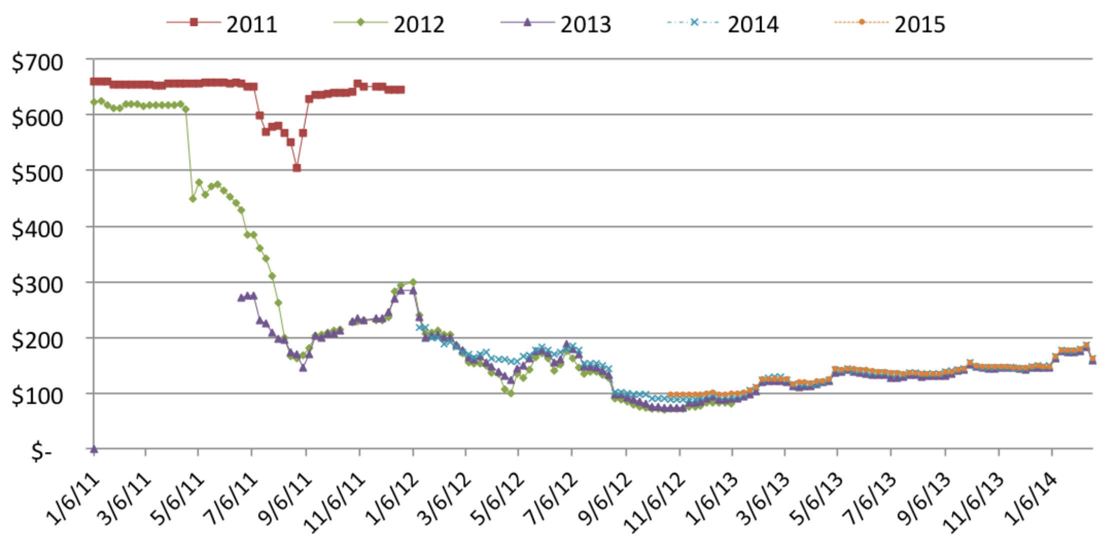
Declining solar installation costs and the attractive investment environment in the New Jersey market resulted in unexpected levels of solar capacity development. In the summer of 2013, there was an over-supply of SRECs in NJ. Assembly Bill A2966 was designed to bring stability back to the New Jersey solar market. This new bill accelerates the SRPS requirement by modifying the requirement curve (previous requirements did not require as much capacity in the earlier years of the program), and reduces the SACP. It also promotes development of projects located on brownfields and landfills, and authorizes aggregated net metering for certain public entities.

SREC eligible solar facilities are required to report production based on readings from a revenue-grade meter, commonly known as "production meters."[101] Rules effective June 4, 2012 eliminated production estimation for facilities with a capacity of less than 10 kW. As of December 1, 2012, SRECs are issued only based on output readings from revenue-grade meters. Legislation proposed for the 2014 session would require the BPU to offer a grant program to residents of an amount equal to the resident's cost to purchase and install a production meter, on the grounds that the BPU's production meter requirement creates a disincentive for solar-powered electric generation.[102]

Figure IV-4 shows the historical New Jersey SREC prices observed between January 2011 and February 2014. Different time series refer to the term (compliance period) that the SREC is traded for. Prior to 2012, SRECs traded at relatively high values; however, the unit price went down below $200 at the beginning of 2012.

[101] The average surveyed price for a basic meter installation was found to be $645. http://www.njcleanenergy.com/renewable-energy/programs/metering-requirements/production-meter-requirements-solar-projects-srecs.

[102] http://www.njleg.state.nj.us/2014/Bills/A2000/1737_I1.htm.



Source: SNL

Figure IV-4: NJ SREC Prices

A slowdown in the build-out rate of new solar capacity contributed to higher SREC prices at the end of 2013, going into the first month of 2014.[103] According to data reported by the New Jersey Office of Clean Energy, total installed capacity surpassed 1,204 MW as of Feb 11, 2014. The average monthly build rate for the six months prior to February 2014 is 12.6 MW, according to SRECTrade analysts.

SACPs for NJ are shown in Figure IV-5. The sharp drop between 2013 and 2014 is a result of the changes made in Assembly Bill A2966 – SACPs were lowered to bring stability back to the New Jersey SREC market. SREC useful life in New Jersey is 5 years, i.e. a 2013 SREC can be counted against any SRPS requirement between 2013-2017.

[103] "New Jersey solar REC markets plunge after recent strength" by Amanda Luhavalja, published at www.snl.com on February 21, 2014.

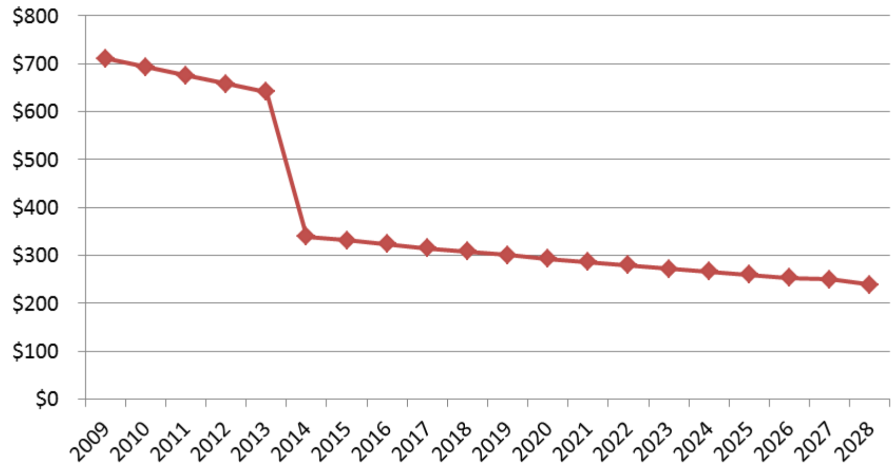
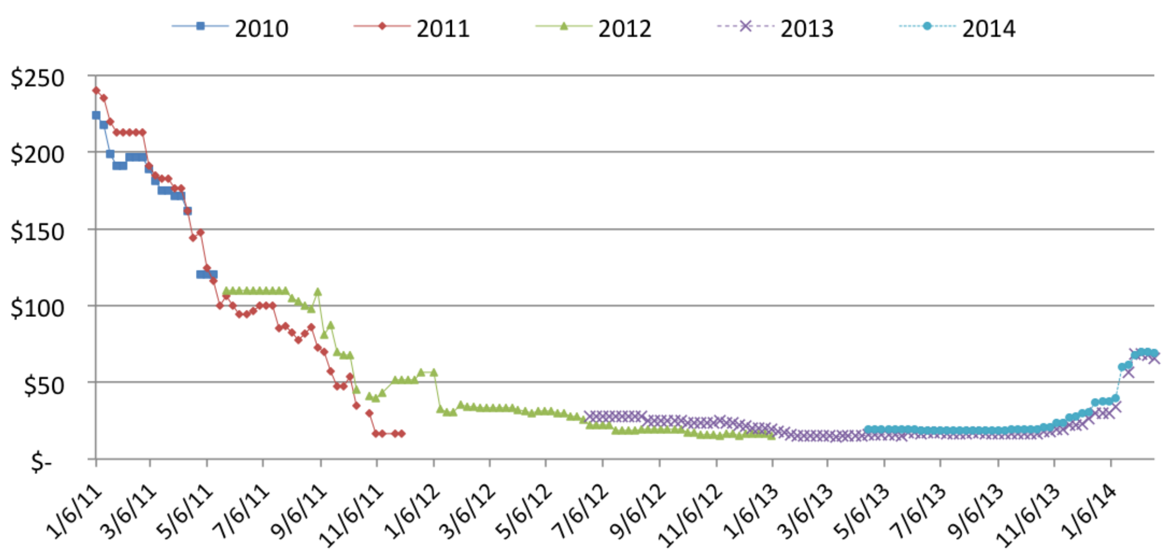


Figure IV-5: NJ SACP per MWh

2. Pennsylvania

Figure IV-6 shows the historical SREC prices observed in Pennsylvania between January 2011 and February 2014.



Source: SNL

Figure IV-6: PA SREC Prices

The Pennsylvania SREC market is oversupplied mainly due to financial incentives provided for solar installation, such as the state-run solar rebate program (Pennsylvania Sunshine program), and the fact that facilities outside the state can register for the SREC market, including those that do not have their own SREC markets (the only other state that allows registration outside the state is Ohio).

The first factor simply led to an increase in the installed solar capacity in Pennsylvania, eventually creating more SRECs. On the other hand, the second factor expands the market area for Pennsylvania SRECs, and results in Pennsylvania subsidizing the solar development in other states. With additional supply of SRECs available due to these two factors, SREC prices in Pennsylvania remained at low levels since 2011. In 2013, SREC prices were approximately $20 – an order of magnitude smaller than the prices prior to 2011.

In 2011, there was a draft bill to address some of the factors of low SREC prices, proposing to move the SREC requirements forward by three years. However, the bill received resistance from the various groups representing the Pennsylvania electricity industry. Most recently in November 2013, another bill was introduced to revitalize the market. Since that time, the expectation of potential policy changes and a slowdown in build-out rates have put an upward pressure on pricing. Consequently, as of February 2014, the SREC prices reached around $70.[104]

Pennsylvania's SACP is determined to be 200% of the average SREC price paid by power provider in that year. Figure IV-7 shows the historical SACP prices between 2010 and 2013. 2021 SACP price is set at $150. Annual prices for the 2014-2020 period will be determined based on SREC prices observed in each year. SREC useful life in Pennsylvania is 3 years.

Figure IV-7: PA SACP Prices

Facilities that have less than 15 kW capacity are required to produce SRECs from estimated generation based on NREL's PV calculator, and all others must report monthly readings.

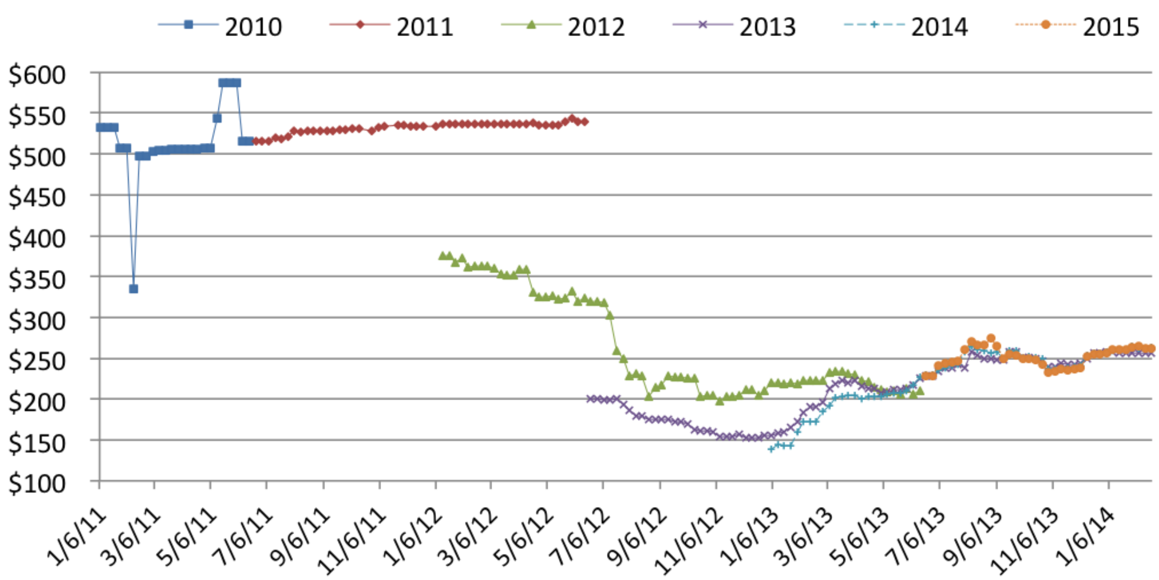
3. Massachusetts

Massachusetts' SREC market was launched by the DOER in January 2010 with a capacity cap of 400 MW. By the end of 2013, the installed solar capacity reached the cap. In fact, as of February 21, 2014, total operational capacity was 415 MW, and the total qualified capacity was more than 600 MW. Recently, the DOER announced the development of a new program, referred to as SREC II, to maintain the growth of the solar market in the state. SREC II is expected to allow a total solar capacity of 1600 MW to produce SRECs by 2020.

[104] "Is the Pennsylvania Solar Market on the Rebound", by Sara Rafalson, published at www.solsystemscompany.com on February 5, 2014.

As mentioned in Section IV.B.3, the DOER utilizes a formula to determine the SREC requirements for each year. Because the formula is based on previous year's market data, requirements are determined at the beginning of each compliance period, and announcement of the new requirements drives the SREC prices of that year.

Figure IV-8 shows the SREC prices observed between January 2011 and February 2014. In 2012, the market became oversupplied (in contrast to the undersupplied 2010 and 2011 periods), and the prices dropped sharply, particularly after the second half of the year. The significant drop in mid-year also corresponds to the end of the compliance period during which buyers had more leverage than sellers, knowing that the market was oversupplied.[105] Since the beginning of 2013, the market prices have been relatively stable, trading at around $250.



Source: SNL

Figure IV-8: MA SREC Prices

To facilitate a robust SREC market and provide price support, the DOER created the Solar Credit Clearinghouse Auction (SCCA) program. The program helps to assure that solar generators maintain the value of their unsold SRECs in over-supplied years by depositing them in the SCCA.[106] At the end of the auction, depositors can either accept the DOER's offer, or choose their SRECs returned to them to be sold in future compliance years. Compliance Year 2012 Auction price cleared at $285 for each unsold SREC.

Massachusetts SACPs are designed to be significantly higher than the market price of SRECs and they will decrease in the future only if DOER determines it is necessary for the market conditions. Furthermore, it will not be reduced more than 10% in any given year. A forward schedule of the SACP was

[105] http://masssolarinfo.com/wordpress/2012/07/07/massachusetts-srec-market-update/.

[106] http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/solar/rps-solar-carve-out/.

published in 2011, with the 2012 payment determined at $550 and the 2021 payment at $365, as shown in Figure IV-9. It should be noted that the SACP rates for the SREC II program have been proposed at lower levels, starting from $375 for 2014, and going down to $257 by 2024[107].

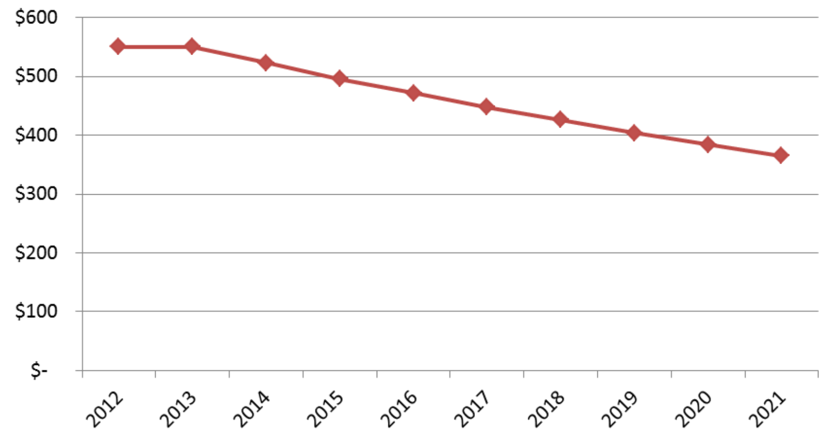


Figure IV-9: MA SACP Schedule

In order to receive SRECs, solar facilities must report generation from revenue grade meters. Facilities with capacities larger than 10 kW must report automatically using an acceptable revenue grade meter online monitoring system.

Retail electricity suppliers must demonstrate compliance by submitting an annual compliance filing to the DOER, documenting that SRECs have been secured.

All unsold SRECs must be deposited in the SCCA at the end of a trading year. If a deposited SREC does not get sold in the SCCA, then the SREC is re-issued and returned to the SREC owner. Alternatively the Massachusetts DOER may purchase some of all of the unsold SRECs using collected SACPs, as it did in 2012. However, re-issued SRECs must be sold within three years of re-issuance and cannot be re-deposited in future SCCAs. Therefore, the useful life of an SREC is limited to three years.

4. SREC Price Stability

SREC prices in a number of states have been quite volatile. In most states examined, the prices plummeted around 2012 because the total amount of supply surpassed the demand much sooner than had been expected by state legislators.[108] Because SREC demand is created by policy requirements while supply is driven by financial incentives, the specifics of RPS design and tax policy play a significant role in the stability of the market. In practice, all states with an SREC market have a price cap through the

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[107] MA RPS Solar Carve-Out II, Final Policy Design, 13 December 2013, available at http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/solar/rps-solar-carve-out/post-400-mw-solar-policy-development.html.

[108] Part of the unexpected oversupply of solar power is attributable to fast declining cost of solar panels. According to a report published by Lawrence Berkeley Laboratory in July 2013, the installed price of grid-connected photovoltaic systems fell by a range of 6 to 14% ($0.3 to $0.9 per watt) from 2011 to 2012. The price drop for systems generating less than 10 kW has been 80% ($2.6 per watt) between 2008 and 2012.

implementation of SACPs, i.e. no matter what the supply conditions are, load-serving entities will pay only up to the price of SACP at the end of a compliance period. On the other hand, SRECs have a limited shelf life, so in a market with no price floor, the traded value of an SREC can easily drop down to zero if the market is oversupplied. An example of price floor design is the Massachusetts DOER's backstop offer to purchase SRECs after the Solar Credit Clearinghouse Auction.

To a large extent, it is the supply and demand balance that determines the traded value of SRECs. Both supply and demand are consequences of the RPS design. An appropriate design could provide stability to the market by establishing price control mechanisms. It should also be emphasized that the RPS design may raise the electricity prices in a jurisdiction and there is usually a spectrum of perceived costs (higher prices) and benefits (green jobs, lower greenhouse gas emissions) in policy-dependent markets such as that for SRECs. It is the state's decision to determine whether or not identified benefits will outweigh the costs of the program in the long term.

D. Estimated Costs and Benefits

A 2012 report prepared by Clean Power Research[109] attempted to identify and quantify various components of the value of distributed solar electricity in seven geographically distinct locations in Pennsylvania and New Jersey. Table IV-4 is taken from that report, and summarizes the identified value components.

[109] "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania", prepared by Clean Power Research, Nov 2012".

Value Component	Basis
Fuel Cost Savings	Cost of natural gas fuel that would have to be purchased for a gas turbine (CCGT) plant operating on the margin to meet electric loads and T&D losses.
O&M Cost Savings	Operations and maintenance costs for the CCGT plant.
Security Enhancement Value	Avoided economic impacts of outages associated due to grid reliability of distributed generation.
Long Term Societal Value	Potential value (defined by all other components) if the life of PV is 40 years instead of the assumed 30 years.
Fuel Price Hedge Value	Cost to eliminate natural gas fuel price uncertainty.
Generation Capacity Value	Generation Capacity Value Cost to build CCGT generation capacity.
T&D Capacity Value	Financial savings resulting from deferring T&D capacity additions.
Market Price Reduction	Wholesale market benefits to ratepayers associated with a shift in demand.
Environmental Value	Future cost of mitigating environmental impacts of coal, natural gas, nuclear, and other generation.
Economic Development Value	Enhanced tax revenues associated with net job creation for solar versus conventional power generation.
(Solar Penetration Cost)	Additional cost incurred to accept variable solar generation onto the grid.

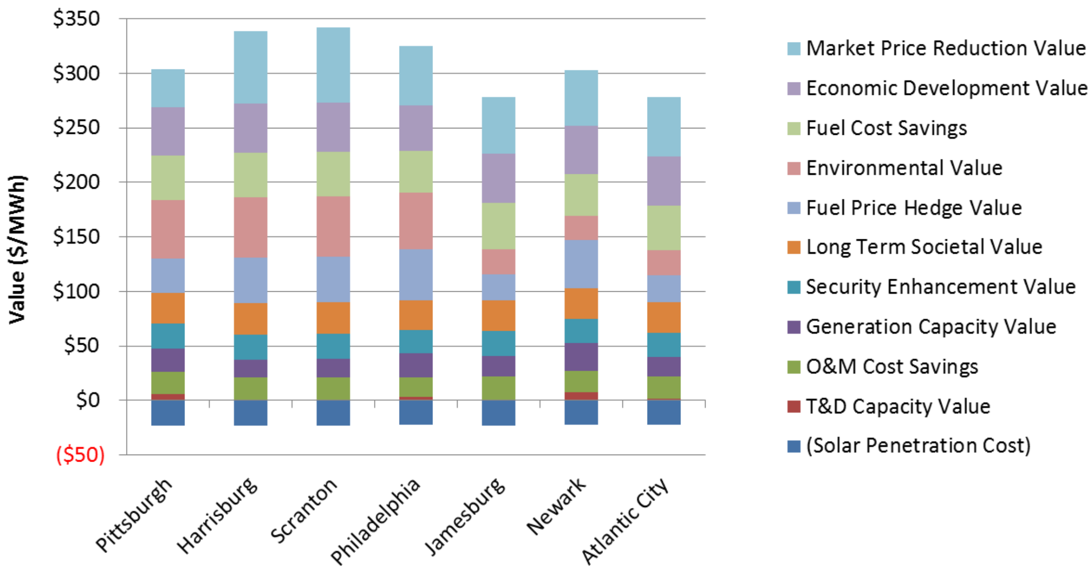
Source: Clean Power Research

Table IV-4: Value Components of Distributed Solar Energy

For each value component identified, the report then estimates the levelized value in terms of $/MWh, and $/kW. These estimations are summarized later in this Section; however it is important to recognize the sensitivity of the estimated values with respect to the assumptions behind the analysis.

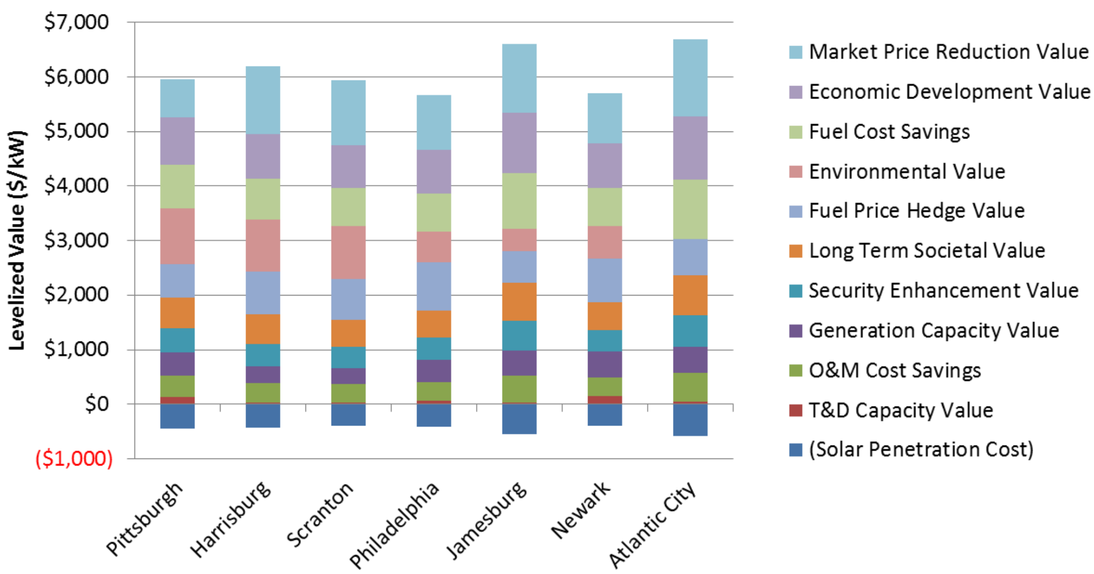
- One of the major assumptions is that total solar capacity penetration is taken as 15% of the utility peak load in the respective region. Costs and benefits may change significantly at other levels of capacity penetration, because the cost of integrating solar into grid increases as the penetration levels increase. In addition, the value of solar per MWh decreases with increasing penetration, mostly because the match between locational marginal prices and solar output is reduced, i.e. the peak shifts to non-solar hours as more solar is added to the electricity mix.
- Another sensitive assumption is the specific configuration of the solar fleet as well as insolation levels in the particular location. The report chose four different system configurations spanning different angles and directions of the panels, but noted that sun-tracking solar panels (which were not part of the study) increases total solar output.
- Some of these components (such as Security Enhancement Value or Long Term Societal Value) are not currently priced or easily monetized; others (Market Price Reduction, Economic Development Value) can be modeled but the models are not easily calibrated; see the discussion of price suppression and economic development benefits in Section III.
- Lastly, utility-specific assumptions around discount rates, fuel prices or distribution losses are also significant parameters that could change the magnitudes of the estimated values

Figure IV-10 and Figure IV-11 were created based on the results of this report, and provide details on the value of components across the locations studied.



Source: Clean Power Research

Figure IV-10: Estimated Levelized Value in $/MWh by Location



Source: Clean Power Research

Figure IV-11: Estimated Value in $/kW by Location

Keeping assumption sensitivities in mind, the main findings of the study can be summarized as follows:

1. The total net value ranged between $256/MWh and $318/MWh across the seven locations analyzed. Highest value components come from market price reduction, averaging at $55/MWh, and the economic development value, averaging at $44/MWh.

2. In terms of value per kW, the total net value ranged between $5,117/kW and $6,704/kW. Highest value components come from market price reduction, averaging at $1,109/kW, and the economic development value, averaging at $905/kW.
3. Solar penetration cost was estimated between $22/MWh and $23/MWh, and $403/kW and $584/kW.

E. Illinois Related Requirements

As alluded to in several sections of this Report (including Key Findings, Section V.B.2, and Section V.D) and further explained in Sections 1-56 and 1-75(c) of the Illinois Power Agency Act and Sections 16-111.5 and 115D of the Public Utilities Act, Illinois has a unique renewable resource procurement structure. Due to the complex and multi-faceted Illinois legal and regulatory structure, none of the other state's approaches described above can be superimposed on Illinois without significant adaptation. That being said, the IPA believes that the experiences of the other states will provide valuable information that the IPA can use to fulfill its statutory mandate to develop solar and distributed solar energy resources.

V. Alternative Compliance Payment Mechanism Fund Report

"[T]he Illinois Power Agency shall submit an annual report to the General Assembly, the Commission, and alternative retail electric suppliers that shall include …

> ***(A) the total amount of alternative compliance payments received in aggregate from alternative retail electric suppliers by planning year for all previous planning years in which the alternative compliance payment was in effect;***
>
> ***(B) the total amount of those payments utilized to purchased [sic] renewable energy credits itemized by the date of each procurement in which the payments were utilized; and***
>
> ***(C) the unused and remaining balance in the Agency Renewable Energy Resources Fund attributable to those payments."***[110]

Each ARES is responsible for procuring the same proportion of cost-effective renewable energy resources as each electric utility, measured as a percentage of prior year load and with costs calculated on a per kilowatt hour basis.[111] To the extent the ARES complies by procuring renewable resources, at least 60% of the renewable energy resources procured by an ARES must be from wind generation and, starting June 1, 2015, at least 6% of the renewable energy resources procured must be from solar photovoltaics.[112] If an ARES does not purchase at least these levels of specified renewable energy resources, then it is required to make additional ACPs. An ARES must meet at least 50% of its renewable resource requirements by making ACPs, and may meet the entirety of its renewable resource obligation through ACPs.[113] All ACPs are placed into the Agency's Renewable Energy Resources Fund ("RERF")[114] that could then to be used to purchase RECs.[115] The price paid to procure RECs using monies from the RERF cannot exceed the winning bid prices paid for like resources procured for electric utilities.[116] As of this report date, most ARES have chosen to meet only the minimum amount of the RPS requirement (50%) using the ACP mechanism.

A. Total Amount of ACPs Received

This report must provide the total amount of alternative compliance payments received in aggregate from alternative retail electric suppliers for each planning year in which the alternative compliance payment was in effect.[117] Under the PUA, a "planning year" begins on June 1st of each calendar year.[118] The ACP

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[110] 220 ILCS 5/16-115D(d)(4).

[111] 220 ILCS 5/16-115D(a).

[112] 220 ILCS 5/16-115D(a)(3) (the 60% statutory wind energy minimum for ARES is lower than the 75% wind standard for utilities).

[113] 220 ILCS 5/16-115D(b).

[114] Also known as "Illinois Power Agency Fund 836."

[115] 20 ILCS 3855/1-56.

[116] 20 ILCS 3855/1-56(d).

[117] 220 ILCS 5/16-115D(d)(4)(A).

mechanism was "in effect" by September 1, 2010 to require payments by ARES for the period of June 1, 2009 to May 1, 2010.[119] Therefore, this report must provide the aggregate total amount of ACPs for planning years June 2009 – May 2010, June 2010 – May 2011, June 2011 – May 2012, and June 2012 – May 2013. Figure V-1 shows the total ACPs for each year.

Planning Year	Funds Received	Total ACPs
June 2009 – May 2010	2010 – Quarters 3 and 4	$7,148,261.61
June 2010 – May 2011	2011 – Quarter 3 and 4	$5,606,245.18
June 2011 – May 2012	2012 – Quarter 3 and 4	$2,156,777.61
June 2012 – May 2013	2013 – Quarter 3 and 4	$38,382,345.57
Aggregate Total		**$ 53,293,629.97**

Figure V-1: Total ACPs Received

B. Amount of ACPs used to purchase RECs

1. Purchases Made

May 2013 marked the first time the IPA earmarked RERF funds to purchase RECs. The IPA was granted a legislative appropriation to spend $8 million from the RERF in the 2013 fiscal year, which ended June 30, 2013. For the 2014 fiscal year $51 million was appropriated. In May 2013, the IPA for the first time entered into contracts to purchase RECs associated with ComEd's curtailed long-term contracts that were not otherwise purchased by ComEd using the hourly ACP payments.[120]

These purchase contracts are for the delivery year June 1, 2013 through May 31, 2014, and are for up to 121,620 RECs with no minimum delivery levels with a total value of $2.24 million, which corresponds to the amount by which REC deliveries under the LTPPAs were curtailed for the participating LTPPA-holders based on the budget cap and the imputed price of those RECs.[121] There is no direct rate impact of these contracts because they utilize funds already collected from customers of Alternative Retail Electric Suppliers as part of those suppliers' compliance with the Renewable Portfolio Standard. As of March 17, 2014, the Agency has received RECs from the suppliers and made payments totaling $439,737.18 pursuant to the contracts.

Prior to May 2013 the only disbursements from the RERF were temporary transfers of funds to the State's General Revenue Fund pursuant to 30 ILCS 105/5h(a). Of the $7,148,261.61 in total ACPs received

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[118] *See e.g.* 220 ILCS 5/16-111.5(b).

[119] Pub. Act 96-0033 (eff. 7/10/2009); 220 ILCS 5/16-115D(d)(2).

[120] Of the eight LTPPA-holders, seven elected to enter into contracts.

[121] Illinois Power Agency, *2013 Annual Report*, December 1, 2013, at 5. This document, which is available at http://www2.illinois.gov/ipa/Pages/IPA_Reports.aspx#AnnualReports, should not be confused with the *2013 Annual Report on the Costs and Benefits of Renewable Resource Procurement in Illinois*.

for the June 2009 – May 2010 planning year, the State of Illinois transferred $2,000,000 on September 20, 2010 and $4,710,000 on October 15, 2010.[122] The remaining $438,261.61 was not used to purchase RECs and remained in the RERF. The State was required to repay the funds within 18 months of borrowing, and it repaid $2,000,000 to the RERF in March 2012 and the remaining $4,710,000 was repaid in April 2012. Because the funds were transferred from a non-interest earning account, no interest was paid.

In the third and fourth quarters of 2011, the IPA received a total of $5,606,245.18 in ACPs for the June 2010 – May 2011 planning year, in the third and fourth quarters of 2012, the IPA received a total of $2,156,777.61 for the June 2011 – May 2012 planning year, and in the third and fourth quarters of 2013, the IPA received a total of $38,382,345.57 for the June 2012 – May 2013 planning year which, to the extent the funds remain available, will be used in accordance with the IPA Act.[123]

2. Agency Challenges in Spending RERF

As is apparent from the discussion above, the IPA has not spent close to the funds available in the RERF. As the IPA explained in ICC Docket 12-0544 (approval of the 2013 Procurement Plan), Sections 1-56(c) and (d) of the IPA Act prevent the IPA from procuring renewable resources when bundled customers are at or above the rate cap from Section 1-75(c)(2)(E) or the Commission otherwise does not order a renewable procurement. This is because Sections 1-56(c) and (d) tie RERF procurements to utility procurements, including using utility procurements as a price cap for products procured from the RERF. Although the IPA has plans for spending the RERF in the manner outlined in Section 1-56(b) of the IPA Act, the IPA believes that absent legislative changes, any procurements using the RERF without an associated utility procurement would risk subsequent legal challenges at significant cost to the IPA and counterparties. The IPA remains actively involved in discussions with stakeholders about what legislative changes would be necessary to allow the RERF to be spent as intended by the General Assembly.

The IPA was able to purchase curtailed RECs using the RERF, because (as noted in Section III.A above) the curtailed RECs had a known price to utility customers (the imputed REC price) and was a product procured for utility customers. The IPA believes that it had the legal authority to make this purchase for delivery year 2013-2014, and would consider purchasing curtailed RECs (if any exist) in future years on substantially similar terms.

C. Balance in RERF attributable to ACPs

As of March 17, 2014, the RERF balance equals $52,853,892.79, the total amount received in the Agency's RERF attributable to ACPs. Figure V-2 shows the current IPA RERF balance sheet. The reported balance significantly exceeds that reported in the 2013 Annual Report as the ACPs received for the June 2012 – May 2013 delivery year in the fall of 2013 totaled $38,382,345.57. These expected payments, in the aggregate, are significantly higher than prior year payments. The higher amount is a direct result of significant load switching from utility supply to RES supply in recent months, primarily driven by municipal aggregation activities.

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[122] 30 ILCS 105/5h(a).

[123] 20 ILCS 3855/1-56.

Date	Transaction	Amount	Cumulative balance
Fall 2010	ACPs received	$7,148,261.61	$7,148,261.61
9/2010	Transfer out pursuant to 30 ILCS 105/5h(a)	($2,000,000.00)	$5,148,261.61
10/2010	Transfer out pursuant to 30 ILCS 105/5h(a)	($4,710,000.00)	$438,261.61
Fall 2011	ACPs received	$5,606,245.18	$6,044,506.79
3/2012	Transfer in pursuant to 30 ILCS 105/5h(a)	$2,000,000.00	$8,044,506.79
4/2012	Transfer in pursuant to 30 ILCS 105/5h(a)	$4,710,000.00	$12,754,506.79
Fall 2012	ACPs received	$2,156,777.61	$14,911,284.40
Fall 2013	ACPs received	$38,382,345.57	$53,293,629.97
Jan./Feb. 2014	RECs purchased per May 2013 Contracts	($439,737.18)	$52,853,892.79

Figure V-2: IPA RERF Balance Sheet

D. Future Use of the ACP-Funded RERF

The ACP mechanism is a useful construct to comply with RPS requirements in a competitively neutral way. That is, it allows an opportunity for additional customer costs of renewable resources to be the same, on an average cents per kilowatt-hour basis, whether the customer takes electricity supply from a utility or an ARES. Although there was no statutory requirement to do so, in its 2014 Procurement Plan currently pending rehearing of the ICC Final Order the IPA included as a courtesy to interested parties a description of the IPA's decision to use the RERF to procure renewable resources. That plan included:

- If there are no changes in law and the ICC does not authorize renewable resource procurements on behalf of eligible retail customers, then the IPA will plan to spend some of the RERF funds on curtailed RECs on a one-year basis. The IPA is currently taking this action for RECs curtailed by ComEd in the current delivery year. In the current year, the IPA plans to purchase up to 121,620 curtailed RECs at a total expected cost of up to $2.24 million
- If there are no changes in law and the ICC does authorize renewable energy resource procurements on behalf of eligible retail customers, then the IPA will use some or all of the RERF to expand the budget for the procurements according to the IPA's highest product priorities
- If there are changes in law sufficient to allow the IPA to procure renewable energy resources at the IPA's discretion and not necessarily in conjunction with a utility procurement, then the IPA plans to spend funds from the RERF in accordance with the provisions of Section 1-56(b). In particular the IPA will seek to achieve the goals for procuring solar and distributed renewable energy resources. Section1-56(b) also specifies that 75% of resources procured come from wind. The IPA will analyze

> the quantities of wind procured via the purchase of curtailed RECs described above and will fill the balance of the requirement with RECs from existing wind energy facilities.[124]

The ICC did not authorize a renewable procurement on behalf of bundled customers, and during the pendency of the approval process there was no change in law. As noted above, the current status quo (until market conditions change) is a capped budget for bundled customers and an increasing RERF that the IPA does not currently have the authority to spend.

Despite some setbacks in spending the RERF and inflated rate impacts based on customer migration, the IPA is pleased to report that there have been significant benefits to customers due to IPA renewable resource procurements. Although the exact benefits are difficult to fully quantify, the IPA looks forward to using the lessons learned from its previous procurements and from solar programs in other jurisdictions to deliver increasingly more benefits relative to costs for Illinois electricity consumers.

[124] IPA 2014 Procurement Plan as filed for ICC Approval at 106 (September 30, 2013).