2016

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

4/1/2016

www.illinois.gov/IPA

April 1, 2016

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), the Illinois Power Agency submits the attached *2016 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

Director

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

APRIL 1, 2016

I. Executive Summary and Key Findings

Public Act 97-0658, effective January 13, 2012, established the following reporting requirements for the Illinois Power Agency ("IPA") with respect to renewable resources procurement:

> Utility Renewable Resource Costs and Benefits
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> *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.*[1]
>
> Alternative Retail Electric Supplier ("ARES") Renewable Resource Costs and Benefits
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> *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 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 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.*[2]

This report is submitted in accordance with these provisions of the Illinois Power Agency Act and Public Utilities Act. Its analysis includes the costs and benefits associated with the following renewable

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

[2] 220 ILCS 5/16-115D(d)(4).

resource purchases facilitated by the IPA under procurements enabled or mandated by Illinois law or conducted in accordance with IPA procurement plans reviewed and approved by the Illinois Commerce Commission ("ICC"), described below:

Ameren Illinois Company ("Ameren") Procurements

05/18/09	Renewable Energy Credit ("REC") Procurement
05/18/10	REC Procurement
12/9/10	20-Year Bundled REC and Energy Procurement
05/18/11	REC Procurement
02/16/12	Rate Stability REC Procurement
05/10/12	REC Procurement
04/16/15	Solar Photovoltaic REC Procurement
10/8/15	Distributed Generation REC Procurement

Commonwealth Edison Company ("ComEd") Procurements

05/11/09	REC Procurement
05/18/10	REC Procurement
12/910	20-Year Bundled REC and Energy Procurement
05/18/11	REC Procurement
02/16/12	Rate Stability REC Procurement
05/10/12	REC Procurement
04/16/15	Solar Photovoltaic REC Procurement
10/8/15	Distributed Generation REC Procurement

Renewable Energy Resources Fund

Winter/Spring 2014	Curtailed REC Purchase
06/18/15	Supplemental Photovoltaic REC Procurement
11/12/15	Supplemental Photovoltaic REC Procurement
03/31/16	Supplemental Photovoltaic REC Procurement (Pending approval from the Illinois Commerce Commission)

Additional information about the utility procurements is included in Appendix A, and about the use of the Renewable Energy Resources Fund in Section V.

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 which 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

- As described above, the IPA has conducted a number of procurements of renewable energy resources over the past seven years. The average price paid for those resources has varied significantly by procurement: in the ComEd territory, the average cost of purchasing renewable energy resources has ranged in price from 19.27/REC in the IPA's first procurement in 2009 to $0.88/REC in the 2012 procurement. In the April 2015 procurement, the cost of solar photovoltaic RECs purchased averaged $43.03/REC. In the Ameren territory, the average cost of purchasing renewable energy resources ranged from $15.86/REC in the 2009 procurement to $0.92/REC in the 2011 procurement. In the April 2015 procurement, the cost of solar photovoltaic RECs purchased averaged $45.51/REC. The distributed generation ("DG") procurements resulted in one winning bidder with the average purchased cost of the DG RECs of $116.65/REC ($113.30/REC for ComEd and $123.78/REC for Ameren). The Supplemental Solar Photovoltaic ("PV") RECs procurements required by Section 1-56(i) of the IPA Act, in which participating photovoltaic systems were required to be "new" and qualify as distributed generation, resulted in purchased costs of an average of $134.84/REC in June 2015 and $142.66/REC in November 2015.

- This report also features a review of existing studies on the costs of intermittency, in particular as they relate to Regional Transmission Organizations/Independent System Operators. The main findings from these studies that are of relevance to MISO and PJM are: the PJM system with adequate transmission expansion and additional regulating reserves will not have any significant issues operating with up to 30% of its energy provided by wind and solar generation; and, because of MISO's large size, both geographically and in terms of load, MISO has not seen a need to increase reserves due to growing generation from wind resources. Illinois currently obtains 5.6% of its generation from these intermittent sources.

- In previous *Annual Reports on the Costs and Benefits of Renewable Resource Procurement in Illinois,* the Agency reviewed evidence that the Illinois Renewable Portfolio Standard ("RPS") appears to have enabled significant job creation and economic development opportunities as well as environmental benefits. Updated studies suggest that increasing the RPS target could increase those benefits.

- In the 2015 edition of this report, the IPA reviewed how energy storage technologies could potentially be applied to help better meet the needs of Illinois electric customers. The 2016 report provides a brief update to that review in Section IV.

- This report features an analysis of the status of alternative renewable distributed generation ("DG") and discusses the role that these technologies could play in providing additional renewable energy resources to help meet the electricity needs of Illinois customers in a more environmentally compatible way (for purposes of this analysis, alternative renewable DG constitutes renewable energy sources other than wind, solar or hydro).

- The IPA's renewables procurements conducted on behalf of the utilities are limited to the dollar amount of the utilities' renewable resources budget (limited by the share of load served and a 2.015% rate impact cap). If customers depart bundled service for other supply options, then the utilities – through no action of their own or the IPA's – could have renewables purchase obligations in excess of their budget caps. Such a situation occurred in delivery years[3] 2013-14 and 2014-15, when ComEd was required to curtail purchases of energy and RECs from its Long-Term Power Purchase Agreements. The return of customers to the utilities' bundled service means that there were no curtailments of those contracts during the 2015-16 delivery year and none are planned for the 2016-17 delivery year.

- The Renewable Energy Resources Fund ("RERF") may be used by the IPA to procure additional RECs to what the IPA procures for the utilities. The funding for the RERF is collected from Alternative Retail Electric Suppliers ("ARES") on an annual basis through alternative compliance payments ("ACPs"). For the planning year June 2014 to May 2015, $86,278,411 in total ACPs were received. The IPA conducted supplemental PV procurements in June 2015, November 2015, and March 2016 and is on track to commit approximately $30 million from the RERF for new distributed photovoltaic projects located in Illinois. Under Public Act 99-0002, $98,000,000 of RERF funds were transferred to the Illinois General Revenue Fund, effective April 1, 2015, without a repayment provision. As of the date of this report, the IPA has not received a Fiscal Year 2016 appropriation to spend funds from the RERF. Coupled with the precedent set by the transfer of RERF funds to the General Revenue Fund in Fiscal Year 2015, the IPA faces significant challenges making long-term commitments from the RERF such as would be needed to encourage the development of additional new renewable energy generation.

[3] A delivery year refers to the period of time from June 1st of one year to May 31st of the following year.

II. Report Methodology

This report draws upon publicly available data regarding electric utility load, DG costs and market performance, procurement results, and ACP fund reporting. Although the Renewable Portfolio Standard ("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,"[4] this report focuses its analysis on the period from June 2009 through January 2016. 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 contracted 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.

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.[5] 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."[6] The bill impacts are presented both 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://www.illinois.gov/ipa/Documents/April-2012-Renewables-Report-3-26-AAJ-Final.pdf.

The IPA would like to thank ComEd and Ameren for their assistance in providing the data necessary for this report. The IPA also would like to thank Levitan & Associates, Inc., the Agency's procurement planning consultant, for their assistance in preparing this report.

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[4] 20 ILCS 3855/1-75(c)(5).

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

[6] 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."[7]

Results are presented for the 2015-2016 delivery year for each electric utility below. Historical results are presented in Appendix B. In order to place the costs of renewable resources and conventional supply generation on a level footing, procurement costs are compared for RECs and electricity contracted or delivered to the utility's bundled rate customers during each delivery year. For each delivery year, the following costs are tabulated:

- The weighted average cost of RECs procured by the Agency;
- The weighted average cost per MWh of the blocks of electricity procured by the Agency;
- The 2010 Long-Term Power Purchase Agreements ("LTPPAs") purchase costs broken down to show the imputed REC and electricity prices[8], beginning with the 2012-13 delivery year, which is the first year of delivery under those agreements; and
- The 2012 Rate Stability Procurement costs of RECs and electricity, beginning with the 2013-14 delivery year, which is the first year of delivery under those agreements.

With regard to the 2010 LTPPAs, the contracts contain bundled pricing for electricity and RECs. REC prices are "imputed" by subtracting an electricity price from the bundled price. The electricity 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.[9]

Although the Agency's costs associated with procuring RECs are compared to the Agency's costs associated with procuring electricity in the tables 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 electricity produced from renewable energy resources, not the value of the underlying electricity. On the other hand, the values shown for electricity procured represent prices of actual electricity procured for delivery and 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 Agency also notes that the costs reported

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[7] 20 ILCS 3855/1-75(c)(5)(A).

[8] In its December 19, 2012 Order the ICC allowed for the release of the previously confidential "Appendix K" imputed REC prices. The conformed plan (ICC Docket No. 12-0544, 2013 Electricity Procurement Plan Conforming to the Commission's December 19, 2012 Order at 84) included imputed prices for the five subsequent Delivery Years 2013-17.

[9] Illinois Power Agency, ICC Docket No. 09-373, Supplemental Filing (Nov. 9, 2009).

herein are only for the supply of electricity and do not include distribution, transmission or other costs related to the provision of electric service.

The average price per MWh for the blocks of electricity listed in the following tables and in Appendix B only includes procurements conducted by the IPA. Through 2013, the portfolio that served ComEd and Ameren eligible retail customers[10] also included financial swap contracts that were part of the 2007 settlement that created the IPA. Because the IPA did not procure those swap contracts, they are not listed here, but it should be noted that over time, they resulted in prices significantly above the market price of electricity. This price disparity was likely one of the main drivers of a large load migration away from the utilities' bundled rate offerings in 2012 and 2013, which in turn triggered the curtailment of deliveries under the LTPPAs discussed in this report. A summary of the IPA's historical procurements of renewable energy resources is presented in Appendix A.

[10] "Eligible retail customers," as used here and in the Public Utilities Act ("PUA"), refers to "those retail customers that purchase power and energy from the electric utility under fixed-price bundled service tariffs, other than those retail customers whose service is declared or deemed competitive under Section 16-113 and those other customer groups specified in this Section, including self-generating customers, customers electing hourly pricing, or those customers who are otherwise ineligible for fixed-price bundled tariff service." (220 ILCS 5/16-111.5(a)). As required by Section 16-111.5 of the PUA, the IPA procures supply to meet the load requirements of these customers.

1. ComEd

Table III-1 shows a comparison of the cost of RECs relative to the cost of electricity under contract for delivery to ComEd in the 2015-16 delivery year. Table B-1 through Table B-6 in Appendix B show comparisons of the cost of RECs relative to the cost of electricity delivered to ComEd for each of the previous six delivery years.

Table III-1: Relative Cost Comparison of RECs and Electricity under Contract to ComEd in the 2015-16 Delivery Year

Cost of RECs and Electricity Under Contract for Delivery to ComEd in the 2015-16 Delivery Year				
Procurements of Renewable Energy Resources	**Quantity**		**Average Unit Price**	**Contracted Cost**
2015 One-Year Solar REC Procurement	49,770	RECs	$43.03	$2,141,737
2012 Rate Stability REC Procurement	202,479	RECs	$2.42	$490,678
2010 Long-Term Purchase Agreements REC Procurement[11]	1,261,725	RECs	$17.92	$22,612,737
Total RECs	1,513,974	RECs	$16.67	$25,245,153
2015 Five-Year Distributed Generation REC Procurement[12]			$113.30	
Long-Term Renewable Energy, 2010 Long-Term Purchase Agreements[13]	1,261,725	MWh	$40.64	$51,270,734
Electricity Procured from Conventional Energy Resources	**Quantity**		**Average Unit Price**	**Contracted Cost**
2015 Spring Block Energy Procurement	7,686,450	MWh	$32.80	$252,135,377
2015 September Energy Procurement	4,763,225	MWh	$33.22	$158,245,305
2014 Spring Energy Procurement	1,258,400	MWh	$40.45	$50,902,864
2012 Block Energy Procurement, Rate Stability	3,952,800	MWh	$34.22	$135,264,948
Total Conventional Energy Resources	17,660,875	MWh	$33.78	$596,548,494

11 This represents the Annual Contract Quantity Commitment of RECs specified in the contract and the imputed REC price. There were 44,931 Carry-Over RECs delivered in the 2014-15 delivery year that will be applied toward the 2015-16 delivery year Annual Contract Quantity Commitment; Carry-Over RECS are not included here.

12 In accordance with the procurement RFP rules and previous Illinois Commerce Commission orders, quantity information is only released when the number of successful bidders in a procurement is greater than two. The results of the 2015 Distributed Generation Procurement did not meet that threshold, therefore quantity (and contracted cost) is not provided. The IPA also notes that these RECs are purchased using Alternative Compliance Payments previously collected from hourly rate customers; thus this purchase has no rate impact on ComEd's fixed-price rate customers.

13 This represents the energy associated with the Annual Contract Quantity Commitment of RECs specified in the contract and the forward energy price curve developed at the time of the procurement. There were 44,931 MWh of energy associated with Carry-Over RECs delivered in the 2014-15 delivery year that will be applied toward the 2015-16 delivery year Annual Contract Quantity Commitment; Carry-Over MWh are not included here.

2. Ameren

Table III-2 shows a comparison of the cost of RECs relative to the cost of electricity under contract for delivery to Ameren in the 2015-16 delivery year. Table B-7 through B-12 in Appendix B show comparisons of the cost of RECs relative to the cost of electricity delivered to Ameren for the previous six delivery years.

Table III‑2: Relative Cost Comparison of RECs and Electricity under Contract with Ameren for the 2015-16 Delivery Year

Cost of RECs and Electricity Under Contract for Delivery to Ameren Illinois in the 2015-16 Delivery Year				
Procurements of Renewable Energy Resources	**Quantity**		**Average Unit Price**	**Contracted Cost**
2015 One-Year Solar REC Procurement	30,212	RECs	$45.51	$1,375,064
2012 Rate Stability REC Procurement	408,810	RECs	$3.32	$1,357,529
2010 Long-Term Purchase Agreements REC Procurement[14]	600,000	RECs	$13.04	$7,826,000
Total RECs	1,039,022	RECs	$10.16	$10,558,593
2015 Five-Year Distributed Generation REC Procurement[15]			$123.78	
Long-Term Renewable Energy, 2010 Long-Term Purchase Agreements[16]	600,000	MWh	$41.26	$24,756,000
Electricity Procured from Conventional Energy Resources	**Quantity**		**Average Unit Price**	**Contracted Cost**
2015 Spring Block Energy Procurement	3,704,600	MWh	$33.36	$123,590,816
2015 September Energy Procurement	880,000	MWh	$31.79	$27,973,936
2014 Spring Energy Procurement	454,000	MWh	$40.47	$18,373,135
2012 Block Energy Procurement, Rate Stability	1,756,800	MWh	$33.62	$59,059,224
Total Conventional Energy Resources	6,795,400	MWh	$33.70	$228,997,111

[14] This represents the Annual Contract Quantity Commitment of RECs specified in the contract and the imputed REC price. There were 39,968 Carry-Over RECs delivered in the 2014-15 delivery year that will be applied toward the 2015-16 delivery year Annual Contract Quantity Commitment; Carry-Over RECS are not included here.

[15] In accordance with the procurement RFP rules and previous Illinois Commerce Commission orders, quantity information is only released when the number of successful bidders in a procurement is greater than two. The results of the 2015 Distributed Generation Procurement did not meet that threshold, therefore quantity (and contracted cost) is not provided. The IPA also notes that these RECs are purchased using Alternative Compliance Payments previously collected from hourly rate customers; thus this purchase has no rate impact on Ameren's fixed-price rate customers.

[16] This represents the energy associated with the Annual Contract Quantity Commitment of RECs specified in the contract and the forward energy price curve developed at the time of the procurement. There were 39,968 MWh of energy associated with Carry-Over RECs delivered in the 2014-15 delivery year that will be applied toward the 2015-16 delivery year Annual Contract Quantity Commitment; Carry-Over MWh are not included here.

3. Costs of intermittency

Electric power systems must maintain a balance between the demand for power from the system and the total power that is supplied into the system. Because power supply must match demand at all times, and because there is always a possibility of an interruption in generation or delivery of supply, sufficient reserves must be established and maintained to ensure the reliability and stability of the system. These reserves, which include both spinning and non-spinning reserves,[17] along with reactive power[18] and regulation service[19] are known as the ancillary services[20] needed to support the operation of the power system.

Traditionally, power supply sources have consisted primarily of so-called "conventional generation", which include coal-fired plants, nuclear plants, hydro plants, and gas-fired generation. However, the need for a clean environment has resulted in many states enacting renewable energy procurement standards, sometimes referred to as "renewable portfolio standards" (or "RPS"), to help shift certain amount of generation from conventional generation to generating technologies that have less negative impact on the environment ("clean generation"). The drive to meet RPS targets has contributed to the construction of clean generation such as wind plants and solar plants. However, these technologies rely on energy sources (the wind and the sun) which are intermittent in nature, *i.e*. occur at irregular intervals and are not continuous or steady, and vary as a function of the availability of its energy source. Because of their intermittency, these technologies may introduce additional costs to the system. This is due to the fact that wind, for example, exhibits both variability and uncertainty. The variability of wind availability and the uncertainty with which the amount of power produced can be accurately forecasted poses challenges for the reliable operation of the system because it reduces operational flexibility. The costs of intermittency include, but are not limited to the costs for additional reserve requirements, in particular Regulation Service. There is some concern that as the fraction of electricity supplied by intermittent generators grows, additional generation and/or more complex control systems will be needed to maintain the stability and reliability of the power system.

According to statistics published by the U.S. Energy Information Administration, in 2015 Illinois' electric power sector ranked sixth among U.S. states in wind production (Table III-3), the same rank it had in 2014, although Illinois ranks fifth in the country for overall installed wind capacity as of December 31, 2015 according to the American Wind Energy Association ("AWEA"),[21] with over 3.8 GW installed.

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[17] Spinning Reserve is the unloaded generation that is connected and synchronized to the system and that is ready to serve additional demand. Non-Spinning Reserve is the generating reserve that is not connected to the system but that is capable of serving demand within a specified time. [NERC Glossary of Terms – February 19, 2016]

[18] Reactive Power is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. [NERC Glossary of Terms – February 19, 2016]

[19] Regulation Service is the amount of reserve that is responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin. [NERC Glossary of Terms – February 19, 2016]

[20] Ancillary Services are those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system. [NERC Glossary of Terms – February 19, 2016]

[21] American Wind Energy Association, "U.S. Wind Industry Fourth Quarter 2015 Market Report," January 27, 2016, at http://awea.files.cms-plus.com/FileDownloads/pdfs/4Q2015 AWEA Market Report Public Version.pdf , pp. 5 and 7.

Table III-3: Top Ten Wind Generating States, 2015 vs. 2014

2015 Rank	State	2015 Generation from Wind (GWh)	2014 Generation from Wind (GWh)	2014 Rank
1	Texas	44,959	39,371	1
2	Iowa	17,878	16,295	2
3	Oklahoma	14,018	11,862	4
4	California	12,228	13,776	3
5	Kansas	10,927	10,844	5
6	**Illinois**	**10,733**	**10,077**	**6**
7	Minnesota	9,797	9,060	7
8	Colorado	7,441	7,351	9
9	Washington	7,101	7,264	10
10	Oregon	6,675	7,580	8

Source: U.S. Energy Information Administration, ***Electric Power Monthly****, February 2016 and February 2015*

To better understand potential costs associated with intermittency, the IPA conducted a review of existing studies on such costs, in particular as they relate to Regional Transmission Organizations ("RTOs") / Independent System Operators that serve Illinois. The main findings from these studies that are of relevance to the MISO (serving Ameren) and PJM (serving ComEd) RTOs are:

- The PJM system, with adequate transmission expansion and additional regulating reserves, will not have any significant issues operating with up to 30% of its energy provided by wind and solar generation.[22]
- For the PJM system, additional Regulation Service is required to compensate for the increased variability introduced by the renewable generation.[23]
- For the PJM system, renewable generation increased the amount of cycling (start up, shut down, and ramping) on the existing fleet of other generators, which imply increased variable operating and maintenance ("O&M") costs on these units.[24]
- Because of MISO's large size, both geographically and in terms of load, MISO has not seen a need to increase their reserves due to growing wind resources.[25]
- MISO is developing a ramp capability model to help during times when a significant generation ramp is needed, such as during the morning load increase. This model helps to quantify the resources needed to provide that ramp and ensure that there are enough resources that can move fast enough during a specific time. This is different from having enough resources to meet the peak load. For example, if wind is dying off during the morning load increase, MISO needs to be able to move fast enough to keep up with that load even if that day is unlikely to be a peak load day.[26]

[22] PJM: PJM Renewable Integration Study, March 31, 2014.

[23] Id.

[24] Id.

[25] EPRI Journal 2015 No.3 / Kristian Ruud (MISO), November/December 2015.

[26] Id.

- MISO has described the impact of more than 10,000 MW of wind generation on its regulation needs as “little to none.” This small increase in reserve requirements is consistent with the findings of grid integration studies.[27]

Table III-4 presents the penetration of intermittent generation (*from* wind and solar). The penetration represents the ratio of the total intermittent generation, in this case wind and solar, to the total net generation from all the sources of energy. Although Illinois produced a large amount of intermittent energy in an absolute sense, this amount was still a small fraction (5.6%) of its total 2015 production.[28] The penetration rate of wind and solar generation in Illinois has increased slightly over the past three years from 4.8% in 2013 and 5.0% in 2014 to 5.6% in 2015, and ranks 20th highest in the country in 2015 (Table III-4). Because intermittent generation would likely need to represent a sizable fraction of total generation to have a noticeable operational impact on the power system, the low penetration implies that intermittent generation in Illinois is not large enough to have a major impact on system operations. However, it is worth considering that Illinois is interconnected with its neighboring states. Illinois utilities are part of the PJM and MISO RTOs, whose member states include Iowa and Minnesota that rank first and seventh in intermittent energy penetration respectively in 2015.[29]

[27] NREL: Review and Status of Wind Integration and Transmission in the United States: Key Issues and Lessons Learned, March 2015.

[28] Note that the Illinois RPS is calculated as a percentage of demand of a subset of customers, and not as a percentage of generation. The energy generation serving the demand of customers in Illinois may, or may not, be located within the state.

[29] If Illinois were to be considered together with Wisconsin, Iowa, and Minnesota, for instance, the resulting intermittent penetration ratio rises to 10.7%.

Table III-4: Top Twenty States by Intermittent Penetration (Ratio of Intermittent to Net Generation), 2015

Penetration (Rank)	State	2015 Intermittent Wind and Solar Generation (GWh)	2015 Net Generation (GWh)	Penetration (Ratio)
1	Iowa	17,914	57,172	31.3%
2	South Dakota	2,482	9,734	25.5%
3	Kansas	10,934	45,781	23.9%
4	Vermont	443	2,091	21.2%
5	Oklahoma	14,023	76,063	18.4%
6	North Dakota	6,530	36,918	17.7%
7	Minnesota	9,826	57,499	17.1%
8	California	32,374	197,994	16.4%
9	Idaho	2,463	15,170	16.2%
10	Colorado	8,135	52,515	15.5%
11	Hawaii	1,288	9,930	13.0%
12	Oregon	6,805	58,857	11.6%
13	Maine	1,289	12,157	10.6%
14	Texas	45,575	450,604	10.1%
15	New Mexico	2,851	32,858	8.7%
16	Nebraska	3,155	39,291	8.0%
17	Wyoming	3,771	48,932	7.7%
18	Montana	1,970	29,546	6.7%
19	Washington	7,153	109,933	6.5%
20	**Illinois**	**10,821**	**194,103**	**5.6%**

*Source: U.S. Energy Information Administration, **Electric Power Monthly**, February 2016*

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."[30]

A comparison of costs and benefits 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 generation are mainly associated with the benefits of avoiding the use of conventional generation sources that typically burn fossil fuels and emit regulated pollutants. A primary way in which environmental benefits can be measured is in terms of annual emissions reductions, that is, the reduction of pollutants that are emitted by using renewable generation instead of using conventional generation sources such as coal or natural gas fired power plants to generate the equivalent amount of electricity.

By way of example, a recent study by Lawrence Berkeley National Laboratory ("LBNL") and the National Renewable Energy Laboratory ("NREL") found that, on a national level, compliance with individual state RPS requirements in 2013 reduced sulfur dioxide emissions by 77,400 metric tons, emissions of nitrogen oxides by 43,900 metric tons, and $PM_{2.5}$[31] emissions by 4,800 metric tons.[32] In addition, the study found that nationwide RPS compliance resulted in 59 million fewer metric tons of greenhouse gas emissions and reduced water consumption by 27 billion gallons than would have been emitted or consumed by conventional generation sources. Emissions from conventional power plants that use fossil fuels have been linked to lung diseases such as asthma and chronic obstructive pulmonary disorder.[33] 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.[34]

In the LBNL/NREL report, emissions reductions due to compliance with the Illinois RPS requirements in 2013 were estimated to be more than 3,000 metric tons of sulfur dioxide, 1,000 to 3,000 metric tons of nitrogen oxides and up to 250 metric tons of $PM_{2.5}$. These estimates are based on modeling of

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[30] 20 ILCS 3855/1-75(c)(5)(A).

[31] $PM_{2.5}$ refers to particles with diameters 2.5 micrometers or less.

[32] Wiser, R., Barbose, G., Heeter, J., Mai, T., Bird, L., Bolinger, M., Carpenter, A., Heath, G., Keyser, D., Macknick, J., Mills, A., Millstein, D., "A Retrospective Analysis of the Benefits and Impacts of U.S. Renewable Portfolio Standards," Lawrence Berkeley National Laboratory, National Renewable Energy Laboratory, January 2016, NREL/TP-6A20-65005.

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

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

the reduction in fossil fuel generation that is displaced by new renewable generation used to serve RPS obligations in 2013 including all new renewable generation in Illinois, not just the generation attributable to the RECs procured by the IPA.

2. Economic Benefits

Various categories of economic benefits are attributed to renewable energy, including electricity price reductions and economic development. Those benefits are detailed in the subsections below. By counterpoint, critics of renewable energy point to factors that may offset some of its purported benefits, including government subsidization of the industry, reduced land values, wear and tear on local roads during the construction of renewable generators (specifically the delivery of wind turbines), future decommissioning costs, stranding of coal-fired and nuclear generation assets, and increasing spinning reserve requirements.

a) Impact on Electricity Prices

Volatility and Portfolio Diversity

In a June 2012 study, 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 security.[35] Wind power and other forms of renewable energy can also lead to more stable electricity prices by diversifying supply portfolios and softening impacts from fuel price volatility. The U.S. Department of Energy characterizes renewable energy as a tool for mitigating risks posed by electricity price volatility, particularly through the purchase of long-term, fixed-price supply contracts for renewable energy resources.[36] (As with all risk management tools, the costs and benefits of employing a particular price risk management tool have to be carefully analyzed and understood in the context in which it is being used). Renewable energy can also reduce the risk of disruptions in fuel supplies, like natural gas, resulting from transportation difficulties or international conflict.[37] Likewise, wind, solar, and certain other forms of renewable energy are not subject to the uncertainty surrounding future carbon taxes, unlike fossil fuel-fired power plants.[38]

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 RTOs

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

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

[37] Id.

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

responsible for reliable flows of energy. The RTOs ensure that the electrical system is 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. LMPs consist of three components – Energy, Congestion, and Marginal Losses. The Energy component prices the energy purchases and sales in the market, the congestion component prices the transmission congestion costs to move energy within the market from one point to another, and the marginal losses component prices the losses on the bulk power system in the market as a result of moving power from one point to another. An impact on any one of these components will have a corresponding impact on the overall LMP.

However, it is important to note that 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 generation have less impact on capacity prices than do dispatchable power plants. In PJM, the average capacity factor used to evaluate new wind projects in the forward capacity market is currently set at 13%, and solar is set at 38%.[39] Since 2009 MISO has been developing capacity credits, based on the Effective Load Carrying Capability ("ELCC") Study, to determine the capacity value for the increasing fleet of wind generation in the MISO. The MISO system-wide wind capacity credit for the 2015-2016 planning year is 14.7%.[40] New wind generation that does not have any commercial operational history will receive a capacity credit equivalent to the system-wide capacity credit from the ELCC study, for the initial planning year, and thereafter metered data will be used in order to calculate its future wind farm specific capacity credit.

Increases in capacity bids from other generators could counteract reductions in system capacity prices attributable to new renewable generation. 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.

Renewable energy generation, in particular wind generation limited by forecast-dependent fuel availability, creates challenges for grid operators who dispatch generation to balance the moment-to-moment electricity demand as efficiently and reliably as possible. Given the projected increase in wind generation in the MISO footprint, MISO began working with stakeholders in January of 2010 to design and implement a

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

[40] MISO: Planning Year 2015-2016 Wind Capacity Credit, December 2014 ("the ELCC Study").

market mechanism to take advantage of advances in wind technology that make the concept of non-dispatchability of wind generation less applicable. MISO introduced the concept of Dispatchable Intermittent Resources (“DIRs”) which allows intermittent generation to fully participate in the energy markets to allow more economic and reliable grid operations. By definition DIRs are primarily wind generating facilities that are physically capable of responding to dispatch instructions (from zero to a forecasted maximum) and can therefore set the Real-Time energy price. DIRs would be treated comparable to other dispatchable generation, and therefore are eligible for all uplift payments and are subject to all requisite operating requirements.

On June 1st, 2011, MISO successfully launched DIRs, allowing registered wind generation to participate in the Real-Time Energy Market and set the Real-Time price. DIRs are however not eligible to provide Operating Reserves to the Day-Ahead or to the Real-Time Energy and Operating Reserves Markets.

In the 2011 MISO State of the Market Report, MISO’s Independent Market Monitor (“IMM”) reported that average fuel-adjusted energy prices (*i.e*. adjusting for fuel costs) declined 1.4% from 2010. Approximately two thirds of the total change was attributable to a 0.6% decline in average load, increased net imports, and increased generation by intermittent generation (*i.e*. wind).[41]

In the 2012 MISO State of the Market Report, MISO’s IMM reported that DIR participation increased, which allowed wind resources to set the LMP and made congestion more manageable.[42] The IMM further noted that before the introduction of DIR, MISO operators manually curtailed wind generation output regularly to manage congestion and address local reliability issues.[43] Manual curtailments are an inefficient means to relieve congestion because the process does not allow prices to reflect the marginal costs incurred to manage the congestion. This inefficiency is eliminated when DIR units are economically curtailed. The implementation of DIR therefore has had a positive impact on congestion management. The IMM also noted that adoption of DIR has greatly improved MISO’s ability to manage wind output and price it efficiently. Over one-half of all wind generation facilities at the end of 2012 were dispatchable and could respond to economic signals. Wind did set the price in approximately one-third of all intervals, and did so at an average as-offered cost of -$15 per MWh. Wind plants may run at negative prices until the price reaches the point where the negative price exceeds the impacts of the tax benefits and other incentives available to these projects.[44]

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[41] 2011 State of the Market Report for the MISO Electricity Markets, June 2012.

[42] 2012 State of the Market Report for the MISO Electricity Markets, June 2013.

[43] Manual curtailment refers to occurrences when, in the event of congestion, MISO calls wind operators to tell them to curtail production. This manual curtailment process has drawbacks in that it does not send the appropriate signals to the market to indicate that transmission congestion is present and to help reduce it.

[44] Wind plants can offer power at low prices because they have low operating costs and, in particular, no fuel costs, unlike fossil fuel plants. Wind plants can offer negative prices because of the revenue stream that results from the federal production tax credit, which generates tax benefits whenever the wind plant is producing electricity, and payments from sales of products that support state renewable portfolio standards or financial incentive programs. These additional revenue streams make it possible for wind generators to offer their wind power into the wholesale electricity market at prices lower than other generators, and even at negative prices.

In the 2013 MISO State of the Market Report, MISO's IMM reported that nearly 80% percent of all wind units were dispatchable under the DIR program for most of 2013.[45] Those units set the price in over half of all intervals, although typically in narrow areas, and did so at an average as-offered cost of -$11 per MWh.

In the 2014 MISO State of the Market Report, MISO's IMM further reported that installed wind capacity in MISO had grown steadily and now exceeded 14 GW.[46] The IMM further noted that managing wind output was significantly aided by the adoption of the DIR program. The expansion of DIR had almost entirely eliminated manual curtailments as a means to manage congestion caused by wind output or to manage over-generation conditions. In addition, since DIR resources can set prices, they did so in over half of all intervals, at an average of -$7 per MWh. The IMM noted that these low prices set by wind units typically occur in relatively small congested areas.

The reports by the MISO IMM suggest that the implementation of the DIR program has had a positive impact on congestion management in MISO and has, by extension, put downward pressure on the LMPs, since congestion is one of the LMP components. The negative offer prices from the wind units also put downward pressure on the LMPs.

In the 2014 PJM State of the Market Report, the PJM Market Monitor reported that in 2014, 75.25 % of the marginal wind units had negative offer prices, 22.20 % had zero offer prices and 2.55 % had positive offer prices.[47] In the same report, the PJM Market Monitor further noted that there was one hour in 2013 and six hours in 2014 in which the Real Time LMP for the entire system was negative. These negative LMPs in the PJM Real-Time Market were primarily the result of marginal wind units with negative offer prices. In the 2015 PJM State of the Market Report, the PJM Market Monitor reported that in 2015, 75.26 % of the wind marginal units had negative offer prices, 20.93 % had zero offer prices and 3.81 % had positive offer prices. The PJM Market Monitor reports suggest that, similar to MISO, wind units in PJM also put downward pressure on LMPs.

Studies have also been conducted which show the impact of wind generation on LMPs. A Congressional Research Service ("CRS") study conducted for Members and Committees of Congress concluded that wind generation can potentially reduce wholesale electricity prices, in certain locations and during certain seasons and times of day, since wind typically bids a zero ($0.00) price into wholesale power markets.[48] The CRS study was conducted to address specific questions regarding wind power impacts on competitive markets, including whether wind power contributed to negative wholesale price events. The study also concluded that the addition of wind power capacity within competitive power markets can, in some markets and locations and under certain conditions, put downward pressure on electricity market

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[45] 2013 State of the Market Report for the MISO Electricity Markets, June 2014.

[46] 2014 State of the Market Report for the MISO Electricity Markets, June 2015.

[47] 2014 State of the Market Report for PJM, March 12, 2015.

[48] Congressional Research Service: U.S. Renewable Electricity: How Does Wind Generation Impact Competitive Power Markets? (November 7, 2012)

clearing prices. In 2009, PJM conducted a study that considered the wholesale power price impacts of adding 15,000 MW of wind power in the PJM market.[49] Results from the study indicated that the addition of the wind power would decrease wholesale market prices by $4.50-$6.00 per MWh.

As noted above, LMP reductions at the wholesale level are not necessarily directly or immediately reflected in the prices that the IPA (or an ARES) procures for energy that are then translated into the retail rates customers pay. Therefore, while the discussion above is indicative of the impact added renewable generation has on energy markets at the RTO level, it might be of less value in quantifying the direct benefit to eligible retail customers in Illinois.

b) Economic Development

In 2012, the Illinois State University's Center for Renewable Energy modeled the economic impact of wind energy upon Illinois' economy by entering wind project-specific information into the NREL's Jobs and Economic Development Impact ("JEDI") model to estimate the income, economic activity, and number of job opportunities accruing to the state from that project.[50] The 2012 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[51] during the construction and 25-year operational lives of the projects. As of February 2016, NREL lists the current installed wind capacity in Illinois to be 3,842 MW which is approximately 15% greater than the installed wind capacity referenced in the 2012 Illinois State University Center for Renewable Energy report.[52] In order to obtain a reasonable estimate of the economic development impacts associated with the current installed wind capacity in Illinois, the impacts from the 2012 report can be increased by the percentage increase in the amount of current installed wind capacity over the capacity identified in the report. Using this approach, the updated economic impacts associated with the current installed wind capacity in Illinois can be extrapolated to be: 21,942 FTE jobs during construction, 937 permanent jobs, and a total lifetime economic benefit of $6.89 billion.

The 2012 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.[53] 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.[54]

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[49] PJM: Potential Effects of Proposed Climate Change Policies on PJM's Energy Market, January 27, 2009.

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

[51] Id. at 7.

[52] U.S. Department of Energy, National Renewable Energy Laboratory, WINDExchange, Installed Wind Capacity, February 2, 2016.

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

[54] Id.

The jobs and economic benefit estimated in the 2012 report included “turbine and supply chain impacts,” which can also referred to as “indirect impacts.”[55] 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.”[56] The estimated benefit 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.[57]

The analysis in the 2012 report 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,”[58] since local governments can receive significant amounts of revenue from permitting fees.[59] Benefits to landowners identified included revenue from leasing their land, which the report found was “usually greater than that from ranching or farming and it does not require any work from the landowners.”[60] 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.

Other parties have published related statistics. According to the American Wind Energy Association (“AWEA”), wind power supported 3,001-4,000 direct and indirect jobs in Illinois during 2014.[61] This apparently includes manufacturing jobs, which may be supported by wind generation located outside Illinois. A 2016 survey from The Clean Energy Trust in partnership with Environmental Entrepreneurs reports that there are currently an estimated 4,272 jobs in the solar industry and 3,549 jobs in the wind industry in Illinois.[62] An Illinois Science & Technology Institute report conducted with Strategic Economic Research estimated that increasing Illinois’ RPS target to 35% would result in average annual additional jobs of 8,571 by 2030.[63]

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[55] Id. at 21.

[56] *Id*. at 22.

[57] *Id*. at 23.

[58] *Id*. at 11.

[59] *Id*. at 18.

[60] *Id*. at 18.

[61] American Wind Energy Association, State Wind Facts, Illinois Wind Energy, accessed March 2016.

[62] Clean Jobs Midwest. http://www.cleanjobsmidwest.com/story/illinois [read more], March 22, 2016.

[63] Illinois Science & Technology Institute, “Illinois Employment Impacts Due to Energy Policy Changes,” Executive Summary, March 2015.

c) Economic Incentives for Renewable Energy

In recent 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 in the future.

State Incentives

The following state tax incentives impact the benefits derived from renewable energy resources in Illinois:

- 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 that produce power for commercial sale be valued at $360,000 per megawatt of capacity and annually adjusted for inflation according to the United States Consumer Price Index.[64] The depreciation allowance may not exceed 70%. Current law allows this valuation methodology to be used until the end of 2016. This provides greater certainty for all stakeholders in wind energy developments.[65]
- 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.[66]
- Two additional tax credits, while not specific to the development of renewable energy, also can provide value to project developers.
    - 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.[67]
    - A Jobs Tax Credit entitles Illinois employers to a $500 tax credit for hiring individuals certified as economically disadvantaged.

In addition to tax credits offered by the State, the Illinois Department of Commerce and Economic Opportunity ("DCEO") has administered a number of incentive and grant programs designed to support the development of renewable energy in Illinois—its Solar and Wind Energy Rebate Program, Large Distributed Solar and Wind Grant Program, etc.—which served to offset a percentage of project costs or provide a per watt financial incentive for new renewable generation facilities. While these programs have had some success in driving the development of renewable energy generation in Illinois, the current Illinois budget

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[64] 35 ILCS 200/10-605.

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

[66] Pub. Act 96-0028 (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.

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

impasse has resulted in the indefinite suspension of DCEO grant and incentive programs and future availability of DCEO incentive and grant programs for renewable energy is uncertain.

Federal Incentives

At the federal level, the American Taxpayer Relief Act of 2012 modified and extended tax credits and other incentives for wind energy and other forms of renewable energy (including geothermal energy, biomass, and landfill gas). The production tax credit ("PTC"), created under the Energy Policy Act of 1992, provides an income tax credit for generation from eligible renewable technologies, including 2.3 cents per kilowatt-hour for the production of electricity from utility-scale wind turbines for the first 10 years of electricity production.. Since its inception, the PTC has been allowed to lapse four times: in 2000, 2002, 2004, and 2013. Although the credit was extended retroactively in the first three cases, the uncertainty in the market resulted in decreases in new capacity additions ranging from 73% to 93%[68] of the previous year's installed capacity. As described below the PTC was renewed a fourth time in late 2015 as part of a larger renewal/extension of tax credits.

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.

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.

On December 18, 2015, Congress approved and President Obama signed into law the Consolidated Appropriations Act, 2016, which included extensions of the tax credits for wind, solar and other renewable resources. In particular, extensions were granted to the 30% ITC for solar energy and retroactively to January 1, 2015 to the 2.3 cents/kWh PTC for wind resources. The ITC for solar will continue at 30% for commercial and residential solar energy systems through 2018, then decrease annually to reach 10% in 2022. The wind PTC will extend through 2016 then decline incrementally for 2017, 2018, and 2019 subsequently expiring in January 2020.

[68] 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."[69]

The IPA asked Ameren and ComEd to provide breakouts by customer class and delivery year of the additional amounts reflected in the supply charge attributable to renewable resource delivery. These breakouts provide the rate impact associated with the Agency's procurement of renewable resources. When multiplied by the overall billing determinants, the values also 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-5 and Table III-6 and for Ameren in Table III-7 and Table III-8. Note that these rate impacts are only for "eligible retail customers" (i.e., customers that take bundled energy supply service from the utility); customers who buy electricity from an Alternative Retail Electric Supplier ("ARES") are not included in these tables. Table C-1 and Table C-2 in Appendix C show the historical rate impacts and total dollar impacts for ComEd for delivery years 2009-10 through 2013-14. Table C-3 and Table C-4 in Appendix C show the historical rate impacts and total dollar impacts for Ameren for delivery years 2009-10 through 2013-14.

[69] 20 ILCS 3855/1-75(c)(5).

1. ComEd

Table III-5: ComEd Rate Impact - Calculated Bill Impacts by RECs[70]

Customer Class	Description	2014-15 Delivery Year	2015-16 Delivery Year (Through January 2016)
Single Family No Electric Space Heat	Revenue/kWh	$0.1371	$0.1357
	REC/kWh	$0.0019	$0.0015
	Ratio (REC/Revenue)[71]	1.39%	1.11%
Multi Family No Electric Space Heat	Revenue/kWh	$0.1536	$0.1558
	REC/kWh	$0.0019	$0.0014
	Ratio (REC/Revenue)	1.24%	0.90%
Single Family With Electric Space Heat	Revenue/kWh	$0.1080	$0.1057
	REC/kWh	$0.0020	$0.0015
	Ratio (REC/Revenue)	1.85%	1.42%
Multi Family With Electric Space Heat	Revenue/kWh	$0.1162	$0.1140
	REC/kWh	$0.0020	$0.0014
	Ratio (REC/Revenue)	1.72%	1.23%
Watt-hour	Revenue/kWh	$0.1649	$0.1630
	REC/kWh	$0.0020	$0.0015
	Ratio (REC/Revenue)	1.21%	0.92%
Small Load (< 100 kW)	Revenue/kWh	$0.1157	$0.1140
	REC/kWh	$0.0019	$0.0014
	Ratio (REC/Revenue)	1.64%	1.23%

[70] Overall bill (e.g. Revenue/kWh) includes fixed supply charges, PJM services charges, delivery services charges (customer charge, standard metering service charges, 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.

[71] 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 1.39% (2014-15 Delivery Year) means that 1.39% of the total electricity bill of a customer of that class in that delivery year was spent on contracts for renewable energy resources.

Table III‑6: ComEd Total Dollar Impact[72]

Customer Class	Description	2014-15 Delivery Year	2015-16 Delivery Year (Through January 2016)
Single Family No Electric Space Heat	Usage (kWh)	7,749,203,541	7,630,403,220
	Dollar Impact	$14,723,487	$11,445,605
Multi Family No Electric Space Heat	Usage (kWh)	1,795,814,584	2,170,893,690
	Dollar Impact	$3,412,048	$3,039,251
Single Family With Electric Space Heat	Usage (kWh)	350,210,596	229,831,490
	Dollar Impact	$700,421	$344,747
Multi Family With Electric Space Heat	Usage (kWh)	725,399,236	577,641,790
	Dollar Impact	$1,450,798	$808,699
Watt-hour	Usage (kWh)	116,026,938	107,988,920
	Dollar Impact	$232,054	$161,983
Small Load (< 100 kW)	Usage (kWh)	4,050,124,634	2,858,123,030
	Dollar Impact	$7,695,237	$4,001,372

[72] Usage values were reported by ComEd. Dollar Impact values were calculated by multiplying the Usage by the REC/kWh reported in Table III‑5.

2. Ameren

Table III‑7: Rate Impact for Customers Taking Supply from Ameren Illinois

Customer Class	Description	2014-15 Delivery Year	2015-16 Delivery Year (Through January 2016)
Residential Service (DS-1)	Revenue/kWh	$0.086	$0.120
	REC/kWh	$0.00168	$0.00148
	Ratio (REC/Revenue)[73]	1.95%	1.23%
Small General Service (DS-2)	Revenue/kWh	$0.082	$0.115
	REC/kWh	$0.00168	$0.00148
	Ratio (REC/Revenue)	2.03%	1.28%
General Service & Large General Service (DS-3 and DS-4)[74]	Revenue/kWh	$0.050	$0.055
	REC/kWh	$0.00168	$0.00148
	Ratio (REC/Revenue)	3.37%	2.69%

[73] Equals the REC/kWh value for the delivery year customer class divided by the total revenue per kilowatt-hour of the corresponding delivery year customer class. The REC/kWh value is equal to the cost of renewable resources in the delivery year, calculated based on the Alternative Compliance Payment as computed by the ICC, divided by the sum of the actual load of customers on Ameren Illinois fixed price supply (Rider BGS) and the actual load of small customers on Ameren Illinois real time price supply (Rider RTP) during the same period. Thus, a Rate Impact of 1.95% (2014-15 Delivery Year) means that 1.95% of the actual revenue from that class in the given delivery year was spent on contracts for renewable energy resources.

[74] General Service & Large General Service (DS-3 and DS-4) have been declared fully competitive and therefore these classes can no longer take supply from Ameren Illinois fixed price (Rider BGS). Therefore, calculations represent only the load of customers taking supply from Ameren Illinois real time price supply applicable to larger customers (Rider HSS). The REC/kWh value is as described in the footnote above except it only applies to customers and load on Rider HSS.

Table III‑8: Dollar Impact for Customers Taking Supply from Ameren Illinois

Customer Class	Description	2014-15 Delivery Year	2015-16 Delivery Year (Through January 2016)
Residential Service (DS-1)	Usage (kWh)	4,837,194,820	3,171,242,070
	Dollar Impact	$8,128,435	$4,686,975
Small General Service (DS-2)	Usage (kWh)	1,924,883,879	1,364,710,963
	Dollar Impact	$3,222,245	$2,011,218
General Service & Large General Service (DS-3 & DS-4)[75]	Usage (kWh)	2,514,174,959	1,418,140,874
	Dollar Impact	$4,226,580	$2,099,699

[75] General Service & Large General Service (DS-3 and DS-4) have been declared fully competitive and therefore these classes can no longer take supply from Ameren Illinois fixed price (Rider BGS). Therefore, calculations represent only the load of customers taking supply from Ameren Illinois real time price supply applicable to larger customers (Rider HSS).

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."***[76]

An ARES may satisfy its RPS requirement entirely through Alternative Compliance Payments ("ACP"), or through a combination of an ACP payment and self-procurement of eligible renewable resources.[77] An ARES must meet at least 50% of its RPS requirement using the ACP mechanism.[78] While the law allows ARES to meet 100% of the RPS through the ACP mechanism, it appears that most ARES currently choose to use the ACP for the minimum 50% of the required RPS and self-procure the remainder of the requirement. 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.[79] This report has estimated the ACP payment based on the actual published ACP rate and the estimated load of ARES customers.

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[76] 20 ILCS 3855/1-75(c)(5).

[77] The eligibility of renewable resources for ARES RPS compliance differs from that for RPS procurements conducted by the IPA for the utilities. Most notable is the requirement that they come from resources "located in Illinois, within states that adjoin Illinois or within portions of the PJM and MISO footprint in the United States." 220 ILCS 5/16-115D(a)(4).

[78] 220 ILCS 5/16-115D(d).

[79] ARES are required to procure renewable energy or credits equal to at least 10% of total sales. The estimated ACP Rate for ComEd for the June 2015 through May 2016 delivery period is 0.16641 cents/kWh sold, which is equivalent to the cost of buying RECs equal to 10% of sales (the 2015-16 RPS requirement) for 1.66 cents/kWh. The estimated ACP rate for Ameren is 0.14806 cents/kWh, which similarly translates to a REC cost of 1.48 cents/kWh. For comparative purposes, the average market prices of RECs, based on the IPA's own procurement (see Table III-1 and Table III-2), are 1.67 cents/kWh for ComEd and 1.02 cents/kWh for Ameren (note that 1c/kWh is the same as $10/MWh).

Table III-9: ACP Rates[80]

Delivery Year	ComEd Usage Forecast[81] (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	10,557,106,000	0.15923	5,405,499,000	0.14661
June 2014 - May 2015	12,003,838,000	0.18917	5,453,214,000	0.18054
June 2015 - May 2016[82]	15,216,704,000	0.16641 (estimated)	7,131,087,000	0.14806 (estimated)

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-9 above. That is, for an ARES customer in Ameren territory, the ARES rate impact in delivery year June 2014 to May 2015 would be 0.09027 cents per kilowatt-hour for the ACP portion of that ARES's compliance. The ARES would incur additional costs to self-procure the additional renewable resources to meet the balance of its obligations. ARES are not required to disclose those costs.

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 renewable procurement on ARES and utility customers would be similar in dollar amount. The percentage impact on an ARES is shown in Table III-10. However, if ARES procure different or less expensive products (for instance, only purchasing short-term REC supply contracts rather than entering into long-term PPAs), overall ARES costs to comply with the RPS are likely to be lower in the short run than the costs paid by utility default service customers.

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80 The data is sourced from https://www.icc.illinois.gov/electricity/RPSCompliancePaymentNotices.aspx - ACP Rate History as of 7-16-2015.pdf

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

82 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 2015-2016 provided in the Illinois Commerce Commission Alternative Compliance Payment Rate History as of 7/16/2015 has been used.

Table III-10: RPS Compliance - Comparative Rate Impact on ARES Customers

Utility Territory	ACP Rate (c/kWh) (estimated) - From Table III-9	Representative ARES Price (c/kWh)[83]	Maximum Rate Impact on ARES Customers Assuming 100% ACP (estimated)
ComEd	0.16641	7.25	2.29%
Ameren	0.14806	6.24	2.37%

The ICC's estimated ACP Rates for the June 2015 through May 2016 period are shown in Table III-10 above. These estimates include the impact of the 2010 LTPPAs. 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 typical of most ARES. Because price information on ARES direct purchases of RECs is not publically available, an exact calculation of typical or average rate impacts on ARES customers is not possible. It is also important to note that the comparison here is only looking at the supply component of a customer's bill, not the entire bill, so it is not directly comparable to the Ameren/ComEd rate impacts presented in Tables III-5 through III-8.

[83] Representative ARES prices are based on offers found on the Plug In Illinois website for 12-month fixed prices non-green energy contracts as of 2/26/2016. Any monthly fees included with the offers were converted to c/kWh based on a usage rate of 1,000 kWh/month. https://www.pluginillinois.org/OffersBegin.aspx. Note that some plans may contain early termination fees that are not included in the calculation of the representative prices. Some ARES also offer plans with additional levels of renewable energy resources, typically at a premium price. Clarification of the specifications, marketing, and disclosure requirements associated with these plans is currently the subject of a rulemaking proceeding currently pending before the ICC (see Docket No. 15-0512).

IV. Alternative Renewable Distributed Generation Technologies

A. Introduction

Distributed generation ("DG") has a large and growing role in the transition to a cleaner and more efficient electric power generation industry. While Illinois law contains a strict definition of what may be considered a "distributed renewable energy generation device" (and thus eligible for the state's "RPS carveout" specific to distributed generation),[84] DG more generally in the electric industry is understood to refer to a wide range of technologies and energy sources that generate electricity typically from the customer's side of the electric meter (or "behind the meter"), located close to the load, on a scale that is significantly smaller than a central generation plant (conventional generation, or even a renewable technology such as a wind farm or a utility-scale solar installation), and usually connected to the grid through the distribution system as opposed to the transmission system. Under this broader definition, DG can utilize fossil-fuels, but DG based on renewable or environmentally beneficial energy sources offers significant system benefits for increasing the reliability and resiliency of the power grid and helping to meet state renewable portfolio standards.

Renewable DG energy sources include solar, wind, hydro, bioenergy, and waste fuels. Bioenergy and waste fuels are often utilized in combined heat and power applications ("CHP"). DG generating technologies can include: photovoltaics ("PV"); thermal solar systems; wind turbines, small combustion turbines, internal combustion engines (reciprocating engines), fuel cells, and boilers with steam turbines and waste heat recovery. In many cases, energy storage technologies are included under the DG umbrella. While the definition of DG can vary widely in terms of capacity, some definitions do not specify capacity limits but define DG based on location or grid interconnection level. In this discussion, DG refers to generating capacity of 20 MW or less which are reflective of typical DG facilities operating in the U.S.[85] However, it is important to note that under the Illinois Power Agency Act, a "distributed renewable energy generation device" must be "limited in nameplate capacity to no more than 2,000 kilowatts [2 MW]." (See 20 ILCS 3855/1-10).

In an attempt to further explore a previously unaddressed topic of potential interest to policymakers, this chapter focuses on alternative renewable DG technologies which utilize renewable or environmentally beneficial energy sources other than wind and solar photovoltaics. Wind and, in particular for DG, solar PV have been the focus of most state programs seeking to increase DG, including those in Illinois (where those

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[84] See 20 ILCS 3855/1-10 (defining "distributed renewable energy generation device"); 20 ILCS 3855/1-75(c)(1) (creating a procurement requirement for renewable energy resources from such devices).

[85] The 20 MW capacity limit is consistent with DG capacity limits for RPS compliance in California and Oregon and with the capacity limit stated in FERC's Small Generator Interconnection Agreement (see order 792). The DG studies referenced in this chapter typically define DG as involving generating capacity of 20 MW or less. That said, DG capacity limits range from 2 MW in Illinois to as large as 65 MW in Connecticut (see Clean Energy States Alliance, Distributed Generation In State Renewable Portfolio Standards, June 2015).

technologies benefit from an express “carveout” in the state’s RPS). While continuing to develop wind and solar generation remains a vitally important goal, other environmentally beneficial sources, primarily bioenergy and waste fuel that can be utilized in CHP applications, offer significant and possibly overlooked potential for increasing the penetration of DG.[86]

Bioenergy can be derived from the conversion of biomass to a range of energy sources usually produced in solid or gaseous forms. Solid bioenergy for DG utilization can include agricultural and forestry wastes, organic industrial processing wastes such as from pulp and paper processing, and in some cases specifically cultivated energy crops. Aside from wind and solar, biogas may offer the most flexible energy source for renewable DG in that biogas can be obtained from a number of sources and can be utilized by all of the relevant DG technologies.[87] Biogas includes gas produced from landfills, water treatment plants, and the anaerobic digestion of agricultural and food processing wastes. Wood and wood-derived energy sources are also considered to be in this class of energy sources for DG applications; these sources are used in DG scale facilities as well as in generating facilities that are larger than 20 MW, including CHP applications. In CHP applications, the energy source is converted to electricity as well as thermally useful energy which can be utilized on the co-generation site.

Figure IV-1 provides an estimate of the market share of various DG sources in 2015 based on U.S. Energy Information Administration (“EIA”) net generation data.[88] The data regarding DG generation specifically is limited. The EIA has started reporting data for solar PV only for the last two years and does not report specific net generation for other DG technologies. In order to estimate the size of the U.S. DG market, Figure IV-1 includes net generation data that are reasonably assumed to be DG scale (20 MW or less capacity). The net generation data available from the EIA does not provide any indication as to how much of the wood and wood-derived fuels are consumed to generate electricity in DG scale applications so these data are not included in the compilation of DG net generation.

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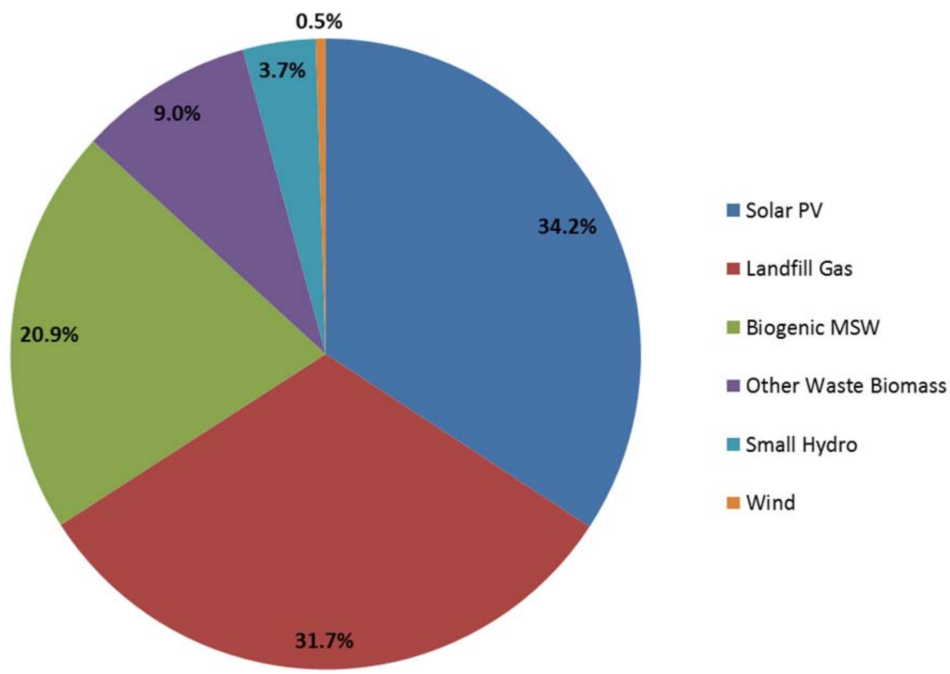
[86] In this context waste fuels include combustible waste products associated with industrial and agricultural processing activities such as black liquor from wood and paper processing.

[87] These technologies, including combustion turbines, boilers, internal combustion engines, and fuel cells are discussed later in this chapter.

[88] The EIA has provided separate data breakout for PV DG net generation for 2014 and 2015. Figure IV-1 provides estimates of the DG energy sources for 2015 based on data provided by the EIA in the February 2016 Electric Power Monthly by assuming that the bulk of the power generated from landfill gas, biogenic municipal solid waste , and other waste biomass is by DG scale technologies, including CHP applications. Likewise, it is assumed that industrial, commercial, and residential wind production is primarily by DG scale technologies. The data reported for wood and wood waste fuels, not shown in figure IV-1, includes significant use of energy sources such as black liquor and other paper processing wastes that are used in CHP applications but not necessarily in DG scale applications.

Figure IV-1: Estimated Market Share by DG Energy Source

(Percent of total net generation, net generation Thousand MWh)



The total estimated DG net generation for 2015 represents just less than one percent of total net generation in the U.S. DG net generation in Illinois in 2015, based on EIA data,[89] is about 1.5 percent.[90]

As the power generation system in Illinois continues to become cleaner and more efficient, alternative renewable DG technologies, such as those discussed in this chapter, could potentially be applied to help meet the needs of Illinois electric customers. In particular, DG technologies could provide additional support for the development, operation and integration of renewable generation resources in Illinois that will promote both a cleaner electricity system and increase job opportunities within the state.

[89] U.S. Energy Information Administration, Electric Power Monthly, February 2016.

[90] This estimate is based on the net generation reported by the EIA for PV DG and adding net generation from industrial and commercial renewables excluding hydro, biomass in industrial and commercial applications, and net generation from landfill gas, which are most likely to be operating at DG scale facilities. It is not directly comparable to the current RPS requirement for utilities to procure 1% from DG for two reasons: first, that RPS requirement does not apply to supply provided by ARES, municipal utilities, or rural electric cooperatives; and second, the utility DG requirement is at the lower 2 MW system size threshold.

As referenced above, the definition of distributed renewable energy devices found in the Illinois Power Agency Act limits participation in IPA DG renewable energy resources procurements to systems with nameplate capacity no larger than 2 MW, located behind the customer meter, and interconnected at the distribution level. The energy sources utilized by the DG systems eligible to participate in IPA procurements include: solar PV, solar thermal, wind, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction of significant expansion of hydropower facilities. However, the intent of this chapter is not to review only those projects eligible for IPA DG procurements; instead, it is to be forward looking in terms of all potential opportunities for Illinois to capture benefits generally associated with alternative renewable DG technologies. Therefore, the discussion of alternative renewable DG systems is focused on DG and CHP systems of up to 20 MW in size.

While increasing renewable generation from sources such as solar and wind within the state will continue to reduce Illinois' dependence on fossil fuels and aid in complying with the Clean Power Plan, those forms of renewable generation can place unique challenges on the operation of electric grids. Most of these operational challenges stem from the fact that wind and solar are intermittent in nature, having variable and uncertain electrical output due to the second-by-second changes in environmental factors outside of a generator's control. These intermittency challenges do not apply to the alternative renewable DG resources discussed here that utilize a storable fuel supply and provide a relatively steady and largely predicable output based on the amount and type of energy consumed.

Update on Energy Storage

The IPA's 2015 report provided a discussion of the energy storage technologies that could address the intermittency issues associated with wind and solar generation. The alternative renewable DG technologies discussed in this chapter generally do not need to rely on energy storage to meet performance requirements, but in some cases could be integrated with storage technologies to provide support for wind and solar generation. Following is a brief update on recent energy storage developments.

As of the first quarter of 2016, the U.S. DOE listed 201 operational electrochemical[91] storage projects (battery-based storage systems) with a total capacity of 405 MW operating in the U.S.[92] Illinois was listed as having 12 projects with 73 MW in operation, placing it among the leaders in states with battery storage projects currently in operation The Energy Storage Association identified 221 MW of storage capacity of all storage technology types added in 2015.[93]

Recent project developments in Illinois included the EDF Renewable Energy 20 MW McHenry Storage Project reaching commercial operation in December 2015 and the announcement by Renewable Energy Systems Americas Inc. in November 2015 that the Jake Energy Storage Center and the Elwood Energy Storage Center had closed on financing and had reached substantial completion. The Federal Energy Regulatory Commission issued an order granting market-based rate authorization for the Jake Energy Storage Center and the Elwood Energy Storage Center on August 10, 2015.[94]

Elsewhere, in December 2015 Southern California Edison Company and Pacific Gas and Electric Company filed for approval of their 2014-2015 storage solicitation agreements representing 16.3 MW and 75 MW, respectively. San Diego Gas and Electric issued its 2016 Energy Storage System Request for Offers on February 26, 2016 seeking to procure up to 140 MW of energy storage capacity. On November 23, 2015 the Ontario Independent Electricity System Operator announced the selection of nine energy storage projects totaling 16.75 MW.

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[91] Electrochemical storage technologies included capacitor projects as well as projects involving flow batteries, lead-acid batteries, Lithium-ion batteries, metal-air batteries, Nickel-based batteries, and sodium-based batteries.

[92] U.S. Department of Energy, DOE Global Energy Storage Database: Projects, http://www.energystorageexchange.org/projects.

[93] Energy Storage Association, U.S. Energy Storage Monitor 2015 Year in Review.

[94] 152 FERC 61,117, Docket Nos. ER15-1907-000 and ER15-1908-000.

B. Alternative Renewable DG

Alternative renewable DG developments to date both nationally and in Illinois have been primarily focused on biogas sources including landfill gas ("LFG"), anaerobic digestion of waste water treatment residuals, and biogas produced from agricultural wastes. Projects have also been developed that involve electricity generation based on the use of solid, gaseous or liquid fuels from agricultural and industrial processing organic residues that are utilized in CHP applications.[95]

Several recent alternative renewable DG installations have been commercialized which involve the utilization of food processing wastes that are processed into biogas for the direct generation of electricity or for use in CHP systems. A review of data from the American Biogas Council and the National Renewables Research Laboratory indicates that there are approximately a dozen food waste to electricity facilities in operation throughout the U.S.; although no food waste processing facilities are listed as operating in Illinois.[96] Organic food waste from sources such as grocery stores, restaurants, institutional food preparation facilities, and food processing plants account for about 15 percent of the total municipal solid waste ("MSW") generated in the United States,[97] and therefore presents a significant potential feedstock. The focus of current and planned food waste projects that produce biogas from anaerobic digestion has been the proper separation of food waste from other less environmentally-friendly materials before this waste ends up in the MSW waste steam.

Biogas from landfills, waste water treatment, and anaerobic digestion of agricultural and food wastes offer the simplest approach to alternative renewable DG since biogas can be easily utilized in all of the DG technologies discussed here for generating power directly and in CHP applications through combustion or electrochemical conversion (fuel cells) to electricity and thermal energy. Excluding LFG, most biogas is produced using anaerobic digestion, which involves the breakdown of biodegradable organic materials by microorganisms in the absence of oxygen and usually under controlled temperatures. After removing water and other minor impurities such as hydrogen sulfide, the biogas, a mixture of about 60 percent methane and 40 percent carbon dioxide, can be burned directly to produce electricity or reformed to provide the energy source for a fuel cell. Anaerobic digestion is used at wastewater treatment facilities to produce biogas for direct electricity generation or for CHP applications. A total of 88 digesters are operating at wastewater treatment plants in Illinois but only four appear to be generating electricity from the biogas that is produced.[98] Nationally the American Biogas Council has identified 239 biogas production facilities on farms with three operating in Illinois; all of the facilities in Illinois are utilizing the biogas for CHP.

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[95] The alternative renewable energy sources considered here do not include Municipal Solid Waste ("MSW") burned to produce thermal or electrical energy; instead, only those MSW products that can be processed into biogas (usually through anaerobic digestion) are considered to be a bioenergy application for purposes of this Chapter.

[96] American Biogas Council. Current and Potential Biogas Production Facility Database.

[97] U.S. Environmental Protection Agency, Municipal Solid Waste in the United States: 2013 Facts and Figures (June 2015).

[98] Water Environment Federation, National Biosolids Partnership, American Biogas Council WWTP Biogas Database.

For most DG applications that utilize LFG, the gas is captured directly from the gases produced by the decay of MSW and is subsequently processed to remove condensate, particulates, and other pollutants such as hydrogen sulfide to produce a combustible gas that is a generally about a 50/50 mixture of methane and carbon dioxide. LFG sources generated 11,233 GWh of electricity nationally during 2015.[99] The U.S. EPA lists 38 LFG projects in Illinois that are currently generating electricity. These facilities have a total generating capacity of 153.7 MW.[100] Based on U.S. EIA data reported for LFG produced for electric generation in Illinois, LFG generated approximately 0.4 percent of the net electricity generation in Illinois during 2015.[101]

Other environmentally preferable energy sources that can be utilized in DG and CHP applications include solid and liquid products that are generally produced from agricultural and industrial processes such as crop waste products, forestry wastes, waste wood, and pulp and paper wastes.[102]

C. DG Technologies for Alternative Renewable Energy Sources

Alternative renewable energy sources can be utilized to generate electricity in a wide range of DG scale technologies. These include direct generation from technologies that utilize bioenergy sources and generation from technologies that utilize these energy sources in CHP applications. The technologies utilized by DG and CHP in this context are the same technologies that utilize fossil fuels to power DG systems including boilers, internal combustion engines, combustion turbines (micro-turbines in smaller CHP and DG applications), and fuel cells. CHP systems typically produce energy in the form of both electricity and heat which are generated from the same energy source. CHP applications, in industrial and commercial applications, generally capture the waste heat from electricity generation and utilize it to meet on-site thermal loads. The high efficiency of CHP applications offers significant environmental advantages over the combustion of various renewable and non-renewable fuels to produce electricity directly. When CHP utilizes waste or by-product fuels that would otherwise have to be disposed of through flaring (in the case of biogas) or in landfills (for liquid and solid waste products), the environmental benefits may be enhanced.

The specific generating technology utilized by an alternative renewable DG application is generally determined by the form of the energy source. For instance, biogas can be utilized by any of the aforementioned technologies, while liquid and solid waste products are generally combusted in a boiler (biogas can also be used in boilers, but in most applications, other technologies are more cost effective). For waste water treatment plants in the U.S. that generate electricity from biogas, 76 percent generated electricity using internal combustion engines, 12 percent from microturbines, 7 percent from turbines, and 5 percent from fuel cells. In Illinois, of the wastewater treatment plants that reported electricity generation in the

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99 U.S. Energy Information Administration, Electric Power Monthly, February 2016.

100 U.S. Environmental Protection Agency, Landfill Methane Outreach Program Database, May 2015.

101 Electric Power Monthly, February 2016, reports that 17,911 million cubic feet of LFG was produced in 2015, assuming an average heat content of 500 Btu/cubic foot and an average heat rate at LFG generation equipment of 13,000 Btu/KWh this results in 688,885 MWh of generation.

102 The Georgia Institute of Technology Center for Paper Business and Industry Studies (CPBIS Data Center) lists 3 pulp mills currently operating in Illinois.

WWTP Biogas Database, three utilized internal combustion engines and one used a gas turbine. For the LFG projects that generate electricity in Illinois, 31 feature internal combustion engines while seven use combustion turbines. The three agricultural biogas facilities operating in Illinois all use internal combustion engines in CHP applications.

Alternative renewable energy sources such as waste fuels produced by agricultural or industrial processes or by anaerobic digesters at wastewater treatment plants in CHP applications can also be effective in meeting on-site electrical and thermal loads. To the extent excess electricity is produced, the excess can be sold into the local electric distribution system. As of the fourth quarter of 2014, CHP systems in the United States using waste fuels, wood and wood wastes, or biomass had an electrical generation capacity of 11,346 MW or about 14 percent of the total U.S. CHP generating capacity.[103] The latest estimate available for total CHP generating capacity in Illinois is 1,329 MW at 141 installations, with about 3 percent of that capacity utilizing renewable energy sources, mostly biogas from landfills, wastewater treatment plants, and agricultural applications supplemented by solid waste fuels at agricultural industrial processing facilities.[104]

The following subsections provide brief descriptions of the DG technologies relevant to this chapter.

a) Boilers

Solid, liquid and gaseous energy sources can be utilized as fuel for boiler combustion to generate steam for on-site thermal load and/or provide steam for a steam turbine to generate electricity. Many biomass power generation facilities burn solids and are primarily boiler combustion/steam turbine systems. Direct combustion boiler systems can involve either fixed-bed (stoker) or fluidized bed boilers. In a fixed-bed boiler system, biomass solids are fed onto a grate where combustion takes place generating hot air which is fed to a heat exchanger to generate steam. A fluidized-bed boiler feeds the biomass solids into a bed of suspended, incombustible particles (usually limestone) where the biomass is combusted to generate the hot air to raise steam. Fluidized bed boilers are more expensive than fixed-bed boilers but allow more complete combustion of the biomass resulting in lower emissions and better system efficiency. While biomass fuels combusted in a boiler are considered to be environmentally preferable and therefore alternative renewables, most of the boiler systems that utilize solid biomass, including wood and wood waste, black liquor and solid agricultural wastes as well as biomass cultivated to be utilized as fuel tend to be larger than 20 MW and therefore are not DG applications.

b) Internal Combustion Engines

Internal combustion engines (reciprocating engines) are utilized for the generation of power in many biogas DG applications. In an internal combustion engine, the rotary motion of the crankshaft drives the electric generator, producing waste heat that can be utilized to produce low pressure steam or hot

[103] The Pew Charitable Trusts, "Distributed Generation: Cleaner, Cheaper, Stronger. Industrial Efficiency in the Changing Utility Landscape," October 2015.

[104] U.S. Department of Energy Combined Heat and Power Installation Database. Combined Heat and Power Installations in Illinois. Data current as of March 1, 2016.

water for CHP thermal use applications. Internal combustion engines for DG applications typically range in size from a few kW up to around 10 MW, although most CHP systems use engines that are 5 MW or less. Internal combustion engines have higher emissions than combustion turbines but are more efficient. In CHP applications of 5 MW or less, internal combustion engines are usually more economic but have lower overall efficiencies than combustion turbines; combustion turbines provide more useable waster heat per kWh generated.

c) Combustion Turbines and Microturbines

Combustion turbines burning biogas, including microturbines,[105] can be used to generate electricity directly or in CHP applications. Combustion turbines can be used in simple or combined cycle configurations and produce waste heat temperatures sufficient to create high pressure steam which can be utilized in industrial process applications or run through a steam turbine to generate additional electricity.[106] To be utilized in a combustion turbine, biogas must be compressed in order to be injected into the turbine's pressurized combustion chamber. In this use, the biogas must be further processed to remove any condensable liquids prior to compression.

d) Fuel Cells

Fuel cells offer relatively high efficiencies and low emissions, particularly in small CHP applications. Electricity is generated in a fuel cell through an electrochemical conversion rather than combustion. Biogas can be used for fuel cells but requires additional processing to reform the methane in the biogas to hydrogen prior to being fed to the fuel cell.

Fuel cells consist of an anode and a cathode separated by an electrolyte. Hydrogen gas catalytically splits on the anode, causing electrons to move from anode to cathode to generate electricity and at the same time ions pass form the anode to the cathode through the electrolyte. The hydrogen ions react with oxygen at the cathode producing water. The following are four of the most prominent types of fuel cells in use or under development:

- Polymer electrolyte membrane or proton exchange membrane (PEMFC),
- phosphoric acid (PAFC),
- molten carbonate (MCFM), and
- solid oxide (SOFC).

Each of these fuel cell designs use different materials of construction and generate electricity under different operating conditions. Some such as the MCFCs and SOFCs reform the fuel gas internally and operate at high temperatures while PAFCs and PEMFCs require the biogas to be reformed externally before use in the fuel cell.

Fuel cells are available for DG with capacities ranging from 1 kW up to 3 MW and can be used in CHP applications. However, some fuel cell designs, notably PAFCs and PEMFCs, produce less

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[105] Microturbines are small combustion turbines with capacities of up to 1 MW, offering an alternative to internal combustion engines in smaller DG applications (especially in locations with tight emissions limits).

[106] In combined cycle operation the combustion turbine is matched with a heat recovery steam generator and steam turbine which generates electricity produced using waste heat from the combustion turbine.

valuable low temperature waste heat only useful for generating low pressure steam or hot water for on-site thermal loads. Fuel cells are the most expensive of the DG technologies, which tends to limit possible applications. Fuel cells have some advantages over other DG technologies for locations with stringent emissions limits such as in California. Fuel cells specifically qualify to meet RPS requirements in 12 states; however, in four of these states the only fuel cells using renewable fuels (biogas) qualify.[107] Illinois law does not currently specifically address fuel cells.

D. Benefits and Costs of Alternative Renewable DG

DG involves benefits as well as costs to the DG project developers, the utility system, and ratepayers in general. The benefits to the utility system include reducing the costs associated with generation, transmission, distribution, and ancillary services. Utility service costs and customer costs can be reduced along with the potential that DG has for reducing the risks of service interruption (thereby reducing the cost of electricity to the ratepayers). DG can also impose costs on ratepayers and the utility system involving the cost to implement supportive DG policies and integrate DG resources into the grid. Financial incentives to encourage DG represent costs that will be borne by the utility, the ratepayer or the tax payer. Other costs associated with DG include the costs incurred by the utility to interconnect and integrate the DG resource into the grid. In some cases, issues related to interconnection costs and requirements set by the utility have become a major point of contention, with state utility commissions taking action to address these issues. Other cost related issues associated with DG that concern utilities and public utility commissions involve the potential negative revenue impacts from loss of load, the rate impacts of spreading utility system costs over fewer ratepayers, and the cost of potentially stranded investments in centralized generating facilities that increased DG penetration would displace.

The costs of DG integration with the electric system involve primarily two components: interconnection costs related to the costs of new lines and equipment needed to connect DG facilities to the distribution system; and the cost of system upgrades or enhancements, such as new communications and control equipment, needed to maintain system reliability. Both of these cost components are highly dependent on where the DG system is located whether in an urban or rural environment and the distance to a suitable distribution grid interconnection point. A study conducted for the California Energy Commission regarding the cost of integrating 4,800 MW of DG on the Southern California Edison distribution system in conjunction with meeting the Governor's goal of 12,000 MW of DG in the state by 2020, showed that for a scenario involving a 50/50 split between urban and rural located DG facilities the total integration costs would range from $190/kW to $270/kW.[108] These are costs that are in addition to the cost of the DG facilities themselves which range from $700 to $1,200/kW for internal combustion engines, $1,200/kW to $1,700/kW for microturbines, $400 to $900 for a combustion turbine, and $3,500/kW to $8,000/kW for fuel cells.[109]

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[107] U.S. Energy Information Administration, Annual Energy Outlook 2015, Table 3. Renewable portfolio standards in the 30 states and District of Columbia with current mandates.

[108] Navigant Consulting, Inc., "Distributed Generation Integration Cost Study Analytical Framework," prepared for the California Energy Commission, November 2013, CEC-200-2013-007.

[109] DNV GL, "A Review of Distributed Energy Resources," prepared for New York Independent System Operator, September 2014.

Renewable DG systems can offer significant environmental benefits, power system reliability and resiliency benefits, opportunities to reduce power generation and transmission capital costs going forward, and improved efficiency. The use of alternative renewable energy sources by DG also avoids the intermittency problems associated with wind and solar applications. The benefits associated with DG are determined to a certain extent by the specific application (industrial, institutional, or municipal), the mix of central plant generation and fuels, the level of new generation and transmission investments needed to meet demand, and by local market and regulatory conditions. In many applications, in particular CHP, the driving force for DG is to improve on-site energy efficiency, lower energy costs, and sell any excess power into the distribution system at a profit. In these applications, the customer itself (rather than the utility or merchant generator) provides the capital investment to build the generating resource. DG systems can offer a lower cost alternative to new investments in central generation and transmission while increasing the reliability of the grid by placing generation closer to the load. Location closer to the load reduces line losses since electricity does not have to be transmitted as far as from centralized generating station to reach the customer. Alternative renewable DG can provide an environmentally preferable use of waste fuels that would otherwise have to be sent to landfill, flared or released into the environment.

In some cases the levelized cost of electricity produced by DG systems is higher than the costs to produce electricity at central generating stations.[110] The higher DG costs have to be adjusted to reflect savings in transmission costs and losses and the overall societal benefits associated with being able to utilize waste fuels resulting in environmental benefits. Recent technological advances, notably involving microturbines, fuel cells and anaerobic digestion systems have reduced the costs and increased the efficiencies of using these technologies for DG in conjunction with alternative renewable energy sources.

The following table provides a comparison of the estimated levelized costs of electricity for DG technologies in the U.S. with the average retail prices for electricity for industrial, commercial and residential customers in Illinois and nationwide for 2013.[111]

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[110] Levelized cost of electricity reflects the average cost of electricity over the life of the generating facility including all of the capital, financing, operating and maintenance, fuel and other costs and reflecting the amount of electricity expected to be generated.

[111] National Association of Clean Air Agencies, "Implementing EPA's Clean Power Plan: A Menu of Options," Chapter 17 Encourage Clean Distributed Generation, May 2015. This study used 2013 data for determining the levelized cost of electricity from the DG technologies shown in Table V-1 and to be comparable, the customer price data were also for 2013.

Table V-1: Range of Levelized Costs of DG and Retail Electricity Costs ($/MWh)

DG Technology or Customer Class	Levelized Cost or Customer Price
Solar PV	$90 - $350
Combustion Turbine in CHP	$40 - $110
Internal Combustion Engine in CHP	$45 - $500
Anaerobic Digestion Wastewater Plant	$70 - $145
Microturbine	$75 - $140
Anaerobic Digestion Farm Waste	$110 - $155
National Electricity Prices	
Industrial	$68.20
Commercial	$102.90
Residential	$121.20
Illinois Electricity Prices	
Industrial	$57.30
Commercial	$78.80
Residential	$102.50

The levelized costs for the DG technologies, other than solar PV, shown in the table above assume the use of natural gas or biogas as an energy source. The anaerobic digestion technologies assume the use of internal combustion engines to generate electricity. Depending on the location and application, some of these technologies are competitive in the context of reducing DG facility owner electricity costs. The competitiveness of these DG technologies is also improved when considering the avoided costs of utility system generation and transmission investment displacement or deferral and the revenues from the sale of electricity that could be produced in excess to the DG owner's on-site needs, which are not considered in the levelized cost of electricity shown above.

E. Relevant Regulatory Issues

DG is governed by a mix of federal and state regulatory oversight and regulation. DG systems are generally connected to the distribution system so that issues relating to DG incentives, rates, and interconnection are typically handled at the state level. The Federal Energy Regulatory Commission ("FERC") has jurisdiction over interconnections to the high-voltage interstate transmission system and the rates charged for transmission which generally does not involve DG. However, some federal legislation such as the Public Utilities Regulatory Policies Act ("PURPA") sets out conditions and rules for non-utility generation and provides incentives for the development of non-utility qualifying facilities. Some PURPA regulations continue to affect DG and CHP. Other federal regulation, notably the regulations governing emissions from power generation and the incentives for clean power, have also served as drivers for the development and implementation of DG.

As of 2015, 29 states and the District of Columbia have implemented mandated renewable portfolio standards.[112] These standards set targets and dates for the amount of electricity generation in the state that must be met with qualifying renewable technologies and specify the technologies and energy sources that qualify. The target percentages for renewable generation among these states range from less than 5 percent to, in some cases such as California, Oregon, Colorado, Maine and Minnesota, more than 30 percent. Most of these targets are to be achieved by or before 2030. Most states allow for the procurement and use of RECs to meet RPS requirements, while other states, such as California, limit REC procurement and focus instead on utility energy contracts with renewable generation projects to meet the targets. In several states, CHP is also qualified to participate in meeting the RPS targets. Six states, including Illinois, "carve out" a specific DG target or provide other incentives for DG to be included as qualifying renewable energy sources.[113]

In Illinois, the current RPS target is 25 percent by 2025, and the RPS includes sub-targets for the procurement of wind (75%), photovoltaics (6%), and distributed generation (1%). However, the Illinois RPS targets—including the 1% distributed generation carveout—apply only to electricity supplied by utilities for eligible retail customers, and not for electricity supplied by ARES (who currently serve the majority of the load in Illinois and are not subject to a specific DG target).[114] The Illinois RPS calls for the IPA to conduct procurements for renewable energy resources from distributed renewable energy generation technologies devices "on an annual basis through multi-year contracts of no less than five years."[115] The first such procurement was conducted in 2015, and the second procurement is scheduled for June, 2016.

A generation source is considered a "distributed renewable energy generation device" under the IPA Act if it is:

- Powered by wind, solar thermal energy, photovoltaic cells and panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams;
- Interconnected at the distribution system level of either an electric utility, alternative retail electric supplier, municipal utility, or a rural electric cooperative;
- Located on the customer side of the customer's electric meter and is primarily used to offset that customer's electricity load; and is
- Limited in nameplate capacity to no more than 2,000 kW.[116]

Further, to the extent available, half of the renewable energy resources procured from distributed renewable energy generation must come from devices of less than 25 kW in nameplate capacity.[117] Notably, the

[112] Barbose, Galen, Lawrence Berkeley National Laboratory, "U.S. Renewable Portfolio Standards: Overview of Status and Key Trends," Clean Energy States Alliance Webinar, January 26, 2016.

[113] In addition to Illinois, these states include: Arizona, California, Colorado, Delaware and Nevada.

[114] As noted elsewhere in this report, the IPA is also conducting procurements of RECs from new photovoltaic DG systems in Illinois as part of the Supplemental Photovoltaic Procurement Plan.

[115] 20 ILCS 3855/1-75(c)(1).

[116] 20 ILCS 3855/1-10.

[117] 20 ILCS 3855/1-56(b).

definition of “renewable energy generation device” found in Section 1-10 of the IPA Act does not include LFG as a qualifying renewable energy source.

F. Alternative Renewable DG Procurement and Policy Issues

Increasing state RPS requirements may drive a growing reliance on DG and provide opportunities to increase the role for alternative renewable energy sources. Recently several states have implemented increases in their mandated renewable resource targets or are planning to do so in the near future. Oregon has set a 50% target for 2040, California 50% by 2030, Vermont 75% by 2032, and Hawaii 100% by 2045.[118] In addition, New York is expected to set a 50% target later this year. Examples of how DG is playing a role in these increased standards include recent Oregon legislation that requires that at least 8% of renewable generation come from community projects or biomass under 20 MW by 2025. In California, the Governor has set a goal of 12,000 MW of renewable DG by 2020. This goal covers renewable DG with a capacity of up to 20 MW. As of the end of October 2015, California had DG projects, on line or pending completion, amounting to 8,090 MW toward this goal; 590 MW (or more than 7%) were from biomass DG.[119] As the power systems in these states increase reliance on renewables to meet the increased standards, alternative renewable energy sources along with storage technologies will be needed to help address the intermittency problems associated with solar and wind generation. The RPS targets found in Illinois law have not been updated since 2009, although there are several legislative proposals that would update and revise them. However those proposals at this time appear to be more focused on increasing opportunities for solar DG rather than expanding opportunities for alternative renewable DG.

Because many alternative renewable DG facilities involve the conversion of bioenergy to electricity, some alternative renewable DG facilities will produce air emissions that are not produced by either solar or wind DG. These DG facilities will be required to obtain the necessary air permits prior to operation, although in these applications the emissions are generally less in terms of magnitude and intensity than the emissions associated with conventional central generating facilities that burn fossil fuels.

Biogas from anaerobic digestion at landfills, farms, food processing facilities, and wastewater treatment plants will be the most likely environmentally preferable energy source to support the increased role for alternative renewable DG. Several states, including Connecticut, Massachusetts and Vermont, have implemented policies designed to reduce the amount of food waste that is being sent to landfills for disposal. These policies have sparked a growing interest in converting food waste to electricity through the anaerobic digestion. DG technologies that utilize LFG sources are the most mature in terms of development, followed by biogas from wastewater treatment plants and biogas production form agricultural applications of anaerobic digesters. Food waste processing is the least developed source but has been growing rapidly in terms of the number of processing facilities that are being built.

[118] Megawatt Daily, March 7, 2016, p.2.

[119] California Energy Commission – Tracking Progress Renewable Energy, Updated December 22, 2015.

Currently the IPA is not aware of any food waste to electricity projects operating in Illinois, only four of the 96 wastewater treatment plants with anaerobic digesters operating in the state generate electricity, and only 38 of the state's 55 LFG facilities that are capable of generating electricity are actually doing so.[120] The potential for biogas to electricity production from these sources in DG technologies has been relatively untapped. The American Biogas Council estimates that in Illinois there is the potential to build an additional 447 biogas facilities, which assuming an average size of 2 MW, would generate more than 6 million MWh or more than 3% of total net generation in the state.[121] This estimate does not include the amount of electricity generated by currently operating biogas to electricity facilities nor the potential for converting to generation operational facilities that do not currently produce electricity.

DG policies and procurements continue to evolve across the United States. Many states have developed policies to aid the integration of DG and more specifically alternative renewable DG into their electric grids. Twenty-six states and the District of Columbia specifically identify LFG as a qualified renewable energy source and 11 states specifically identify anaerobic digestion as a qualifying technology to meet their RPS targets. A number of states, notably California, Oregon and Illinois, utilize market based procurements specifically for DG and for alternative renewable DG energy sources. As stated in both the 2015 and 2016 Procurement Plans, the IPA recognizes that there is a limited amount of DG currently operating in Illinois and that the success of the IPA's DG procurements depends on the ability of the DG market to self-organize and grow.

Several policy changes could drive the development of alternative renewable DG in Illinois. For example, the qualifying capacity of DG facilities for the IPA procurements could be increased from the current 2 MW (with half of the RECs to be procured to be from systems of less than 25 kW), to an upper limit of 10 MW or even 20 MW. Coupled with a reduction in the target percentage to be procured from small DG facilities, increasing the capacity cap could encourage the participation of larger new or existing alternative renewable DG in the IPA's procurements.

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[120] The LMOP Database does not provide any information regarding why the LFG facilities that could produce electricity did not actually do so. The likely reasons are the inability to meet air emissions limits, the inability to operate in an economic manner, or the loss of LFG flows due to depletion.

[121] American Biogas Council, Biogas State Profile: Illinois, updated August 2015.

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."***[122]

Whether through self-procurement or alternative compliance payments ("ACPs"), 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.[123]

Up to, but no more than half of that procurement obligation may be met through self-procurement of renewable energy resources. 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.[124] As of this report date, most ARES have chosen to meet only the minimum amount of the RPS requirement (50%) using the ACP mechanism, presumably because the available price for short-term REC contracts for RECs generated within the MISO or PJM footprints[125] should be significantly lower than the imputed price for RECs purchased pursuant to the 2010 LTPPAs, the price of which is reflected in the ACP rate. ACPs related to ARES' compliance for load served in the energy delivery year beginning June 1, 2016 must be made by September 1, 2017.[126]

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.[127] Starting with the energy delivery year commencing June 1, 2015, at least 6% of the renewable energy resources procured must be from solar PV.[128] If an ARES does not purchase at least the technology-specific sub target levels of specified renewable

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[122] 220 ILCS 5/16-115D(d)(4).

[123] 220 ILCS 5/16-115D(a).

[124] 220 ILCS 5/16-115D(b).

[125] See 220 ILCS 5/16-1115D(a)(4) (this is the geographic requirement for ARES self-procurement).

[126] 220 ILCS 5/16-115D(d)(2).

[127] 220 ILCS 5/16-115D(a)(3) (the 60% statutory wind energy minimum for ARES is lower than the 75% wind standard for utilities).

[128] Id.

energy resources (wind, photovoltaics), then it is required to make additional ACPs at the same rate in order to meet those obligations.

All ACPs are deposited into the Renewable Energy Resources Fund ("RERF"), a state-held fund administered by the Agency to procure renewable energy resources through the purchase and retirement of RECs.[129]

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.[130] Under the PUA, a planning year begins on June 1st of each calendar year.[131] The ACP mechanism was "in effect" by September 1, 2010 to require payments by ARES for the period of June 1, 2009 to May 1, 2010.[132] Therefore, this report must provide the aggregate total amount of ACPs for the planning years 2009-10, 2010-11, 2011-12, 2012-13, 2013-14, and 2014-15. Table V-1 shows the total ACPs for each year. ARES ACP payments are due by September 1st following the end of the planning year. (For example, for the planning year that ended in May, 2015, payments were due September 1, 2015.) Payments are made as part of a Compliance Report submitted to the ICC. The IPA and the ICC work together to ensure that all ACP payments are collected and verified.

Table V-1: Total ACPs Received[133]

Planning Year	Total ACPs Received
June 2009 – May 2010	$7,148,261.61
June 2010 – May 2011	$5,632,587.18[134]
June 2011 – May 2012	$2,156,777.61
June 2012 – May 2013	$38,382,345.57
June 2013 – May 2014	$77,145,921.09
June 2014 – May 2015	$86,278,411.02
Aggregate Total	**$216,744,304.08**

[129] 20 ILCS 3855/1-56.

[130] 220 ILCS 5/16-115D(d)(4)(A).

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

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

[133] Total ACPs Received does not account for expenditures (or other diversions) from the RERF and, therefore, the Aggregate Total reported in this figure will differ from the RERF balance reported in Table V-2.

[134] One additional payment of $26,342 was received in May, 2015 as an adjustment to correct the ACP rate used for that supplier's ACP obligation. Therefore this amount is updated compared to what has been reported in prior reports.

B. Amount of ACPs used to purchase RECs

1. Purchases Made

Prior to May 2013, the only disbursements made 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 for the 2009-10 planning year, the State of Illinois transferred $2,000,000 on September 20, 2010 and $4,710,000 on October 15, 2010.[135] 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 2013, the IPA and ComEd offered to purchase an amount of curtailed RECs which corresponds to the amount by which REC deliveries under the 2010 LTPPAs were curtailed for the participating LTPPA-holders based on the then effective RPS budget cap.[136] In May 2013, the IPA entered into contracts to purchase RECs associated with ComEd's curtailed long-term contracts that were not otherwise purchased by ComEd.[137] These purchase contracts were for the delivery year June 1, 2013 through May 31, 2014, and were for up to 121,620 RECs with no minimum delivery levels with a total value of $2.24 million. The contracts did not require delivery of RECs and, due to improved market prices for RECs elsewhere, not all contract holders exercised their rights to deliver RECs to the IPA. A total of 74,402 RECs were delivered in the June 1, 2013 through May 31, 2014 delivery year under these contracts at a total cost of $1,719,141.52. There was no direct rate impact resulting from these purchases because they used ACP funds previously collected from ARES. As approved in ICC Docket No. 12-0544, ComEd also used ACP funds to purchase 79,674 RECs curtailed under the operation of LTPPAs in the June 1, 2013 through May 31, 2014 delivery year at a total cost of $1,647,596.

Effective June 28, 2014, Public Act 98-0672 created new section 1-56(i) of the Illinois Power Agency Act requiring the Agency to develop a one-time supplemental procurement plan for the procurement of renewable energy credits from new or existing photovoltaics using up to $30,000,000 from the RERF. The Supplemental Plan was developed by the IPA in 2014 and approved by the ICC on January 21, 2015. Three procurement events have occurred pursuant to the Supplemental Plan (June 2015; November 2015; and March 2016), with the results of the third procurement expected to be approved by the ICC on April 4, 2016.

Under the Supplemental Plan, parties bid to sell RECs from potential or identified projects through a competitive procurement process, with time built in to allow for project identification and development

[135] 30 ILCS 105/5h(a).

[136] 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*.

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

before the delivery of RECs. Due to this built-in delay for market and project development prior to the receipt of RECs, and due to a lack of an approved appropriation for Fiscal Year 2016, to date the only expenditures made in relation to this Plan are those for the cost of developing the plan and for conducting the procurement events. As of the publication of this report, the IPA has still not yet received a Fiscal Year 2016 appropriation for the RERF, therefore no payments for RECs have been made.

Public Act 99-0002, effective March 26, 2015, authorized the transfer of $98,000,000 from the RERF to the State's General Revenue Fund. That transfer occurred on April 1, 2015 and does not include a repayment provision, further increasing the differential between ACPs received and the current RERF balance.

2. Agency Challenges in Spending RERF

The procurement of renewable energy resources using the RERF is subject to a set of unique constraints. First, Section 1-56(c) of the IPA Act calls on the IPA to use the RERF to "procure renewable energy resources at least once each year in conjunction with a procurement event for electric utilities required to comply with Section 1-75 of the Act." This "in conjunction with" requirement prevented the IPA from using the RERF in 2013 when there were no procurement events for the utilities.

Second, Section 1-56(d) of the IPA Act requires that "the price paid to procure renewable energy credits" using the RERF "shall not exceed the winning bid prices paid for like resources procured for electric utilities required to comply with Section 1-75 of this Act." The lack of a conjoining procurement event (which may occur when bundled customers are at or above the rate cap found in Section 1-75(c)(2)(E) or the Commission otherwise does not order a renewable procurement) has also left the Agency without a statutorily envisioned price ceiling for "like resources," further constraining procurement using the RERF.

Third, the IPA Act clearly articulates a preference for longer-term contracts using the RERF, presumably to provide a stable stream of revenue necessary to incent the development of new resources. Section 1-56(c) of the IPA Act calls for the Agency to, "whenever possible, enter into long-term contracts on an annual basis for a portion of the incremental requirement for the given procurement year." Similarly, Section 1-56(b) of the Act requires that any contracts for resources from distributed generation must run a minimum of 5 years. But due to unsettled and dynamic load migration between utility and alternative supplier service, the Agency must approach long-term contracting with prudence and care, as the RERF's future balance is subject to the whims of future customer switching.

Fourth, Section 1-56(b) of the IPA Act contains delineated targets for the procurement of RECs from specified types of generation: at least 75% of RECs procured must come from wind generation; at least 6% from solar PV; and at least 1% from DG. In 2014 and 2015, the IPA only conducted procurements for solar PV RECs for the utilities, running into the limitation that for a procurement using the RERF, "at least 75% of RECs procured must come from wind generation," but without any conjoining procurement or price to compare for wind (or other renewable generation technologies) RECs.

Lastly, at different points, the balance of the RERF has been subject to transfers (such as via 30 ILCS 105/5h(a)), through which the bulk of the funds in the RERF were transferred to the General Revenue Fund in 2010 and repaid in 2012, preventing any use of the fund in any of those years), or diversions without payback (such as through Public Act 99-0002), leaving the IPA without available RERF funds with which to conduct procurements for additional renewable energy resources without jeopardizing meeting existing obligations.

Due to these and other challenges, to date the IPA has only spent a small portion of the funds available in the RERF on the procurement of renewable energy credits. However, in the past year, the IPA has committed funds from the RERF pursuant to the Supplemental Photovoltaic Plan authorized by Section 1-56(i) of the IPA Act. Additionally, in calendar year 2016, the conditions appear to exist for the IPA to conduct a procurement using the RERF pursuant to Sections 1-56(b). Those conditions include the procurement of renewable resources for the utilities, notably the expected procurement of wind resources for MidAmerican. However, given the prolonged Fiscal Year 2016 budget impasse (even with these predicate conditions satisfied, the IPA still lacks any appropriation authority to spend the RERF at the time of this report) and the precedent set through Public Act 99-0002's mechanism used to address Fiscal Year 2015 budget challenges, the IPA remains very concerned that a potential transfer of funds out of the RERF may prevent any such procurement from being conducted, and at a minimum could make long-term contracting problematic. Going forward, the IPA will remain involved in any discussions with stakeholders about legislative changes that could allow the RERF to be spent as originally intended by the General Assembly.

C. Balance in RERF attributable to ACPs

As of April 1, 2016, the RERF balance equals $$117,681,260.09. Table V-2 shows the current IPA RERF balance sheet.

Table V-2: IPA RERF Balance Sheet

Date	Transaction	Amount	Cumulative Balance
Fall 2010	ACPs received	$7,148,261.61	$7,148,261.61
September 2010	Transfer out pursuant to 30 ILCS 105/5h(a)	($2,000,000.00)	$5,148,261.61
October 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
March 2012	Transfer in pursuant to 30 ILCS 105/5h(a)	$2,000,000.00	$8,044,506.79
April 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
Winter/Spring 2014	RECs purchased per May 2013 Contracts	($1,719,141.52)	$51,574,488.45
Fall 2014	ACPs received	$77,145,921.09	$128,720,409.54
Fall 2015	Supplemental PV Procurement Expenses	($170,068.33)	$128,550,341.21
Spring 2015	Transfer pursuant to Public Act 99-0002	($98,000,000)	$30,550,341.21
Spring 2015	ACPs Received	$26,342.00	$30,576,683.21
Summer 2015	Supplemental PV Procurement Expenses	($653,549.18)	$29,923,134.03
Summer 2015	SPV Deposits	$427,836.00	$30,350,970.03
Fall 2015	ACPs Received	$86,278,411.02	$116,629,381.05
Fall 2015	SPV Deposits	$492,785.00	$117,122,166.05
Spring 2016	SPV Deposits	$559,094.04	$117,681,260.09

Appendix A. Summary of IPA's Historical Renewable Energy Procurements

The ICC has approved the IPA's procurement of RECs to comply with the entirety of the utilities' RPS-mandated volumes except where the those purchases would increase rates above the cap specified in Section 1-75(c)(2)(E) of the IPA Act. A summary of the ICC's decisions authorizing those procurements is below:

- 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."[138]
- 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.[139] The ICC additionally found that the 2010 LTPPAs "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."[140]
- 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.[141]
- 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.[142]
- No REC procurements were conducted during 2013. The ICC approved[143] 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.[144]
- 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 LTPPAs 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. Based upon updated forecasts provided in March 2013, REC deliveries from the ComEd LTPPAs were

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[138] ICC Docket No. 08-0519, Final Order at 45 (Jan. 7, 2009).

[139] ICC Docket No. 09-0373, Final Order at 127 (Dec. 28, 2009).

[140] ICC Docket No. 09-0373, Final Order at 126, 115, 43 (Dec. 28, 2009).

[141] ICC Docket No. 10-0563, Final Order at 83 (Dec. 21, 2010).

[142] ICC Docket No. 11-0660, Final Order at 84 (Dec. 21, 2011); IPA 2012 Power Procurement Plan (Updated) at 53 (Feb. 17, 2012).

[143] ICC Docket No. 12-0544, Final Order (Dec. 19, 2012).

[144] ICC IPA 2013 Electricity Procurement Plan at 83-84 (Sept. 28, 2012).

curtailed but there was no curtailment of Ameren LTPPAs. While not a procurement conducted by the IPA, the approval of the 2013 Procurement Plan authorized ComEd to use ACP funds collected from customers taking hourly priced service to purchase curtailed LTPPA RECs (but not the associated energy). ComEd purchased 79,674 RECs at a total cost of $1,647,596. The IPA also used RERF funds to purchase curtailed RECs above those that were purchased by ComEd using the available hourly ACP funds.

- No REC procurements were conducted during 2014. The ICC approved[145] the 2014 Procurement Plan without modifying the IPA's recommendation that there should be no new Ameren or ComEd REC procurement event in the 2014 Procurement Plan.[146] The basis for the IPA's recommendation was that the rate cap from Section 1-75(c)(2)(E) of the IPA Act was projected to be exceeded again in the 2014-15 delivery-year. The IPA further recommended that the utilities update their load forecasts in March 2014, and that a decision on LTPPA curtailment would be made on the basis of those forecasts. Based upon those updated forecasts, the ComEd LTPPAs were curtailed; as was the case in 2013, ComEd then purchased 62,266 curtailed RECs at a total cost of $1,887,999 using the ACP funds collected from its hourly customers. There were sufficient funds to purchase all the curtailed RECs and therefore the IPA did not need to extend an offer to purchase remaining curtailed RECs using the RERF.
- In its 2015 Procurement Plan, the IPA recommended that as the target total renewables and wind requirements are forecasted to be met in the 2015-16 delivery year, no additional wind or generic renewable resources should be procured on behalf of Ameren or ComEd. The IPA did, however, note that the PV and DG requirements for both utilities were not forecasted to be met and recommended that a Spring 2015 procurement of Solar Renewable Energy Credits and a September 2015 procurement of DG RECs (using already collected hourly ACP funds) be conducted to meet each utility's PV and DG requirements for the 2015-16 delivery year.[147] The ICC accepted these recommendations.[148] The Commission also separately approved the supplemental procurement of RECs from new distributed PV systems, authorized by Public Act 98-0672, using $30,000,000 from the IPA's Renewable Energy Resources Fund.[149]
- In its 2016 Procurement Plan, the IPA noted that the load forecasts provided by the utilities on July 15, 2015 indicated that existing renewable energy resources under contract for Ameren Illinois and ComEd did not meet or exceed the RPS obligations for solar PV or for DG. MidAmerican had not previously been a part of the IPA procurement process, or subject to its provisions, and thus it did not have any resources previously procured to meet its overall renewable energy resource obligations or its specific obligations for wind, PV, or DG. Accordingly, the IPA recommended conducting a spring procurement event for general RECs (MidAmerican only), wind (MidAmerican only), and solar RECs (all utilities) using the Renewable Resources Budget. The IPA also proposed an early summer procurement for DG RECs using hourly ACP funds for Ameren Illinois and ComEd, and using the Renewable Resources Budget for MidAmerican. For Ameren Illinois and ComEd, the DG procurement budget will be equal to

[145]ICC Docket No. 13-0546, Final Order (Dec. 8, 2013).
[146]IPA 2014 Electricity Procurement Plan at 102 (Sept. 30, 2013).
[147]IPA 2015 Electricity Procurement Plan at 100, 102, and 107 (Sept. 29, 2014).
[148]ICC Docket No. 13-0588, Final Order (Dec. 17, 2014).
[149]ICC Docket No. 14-0651, Order (Jan. 21, 2015).

the amount of hourly ACP funds collected by each utility as of May 31, 2016, minus the value of contracts awarded through the Fall 2015 DG REC procurement and any hourly ACP funds committed to the purchase of curtailed RECs stemming from the 2010 LTPPAs.[150] The ICC accepted these recommendations.[151] The REC procurement is scheduled for May 4, 2016, and the DG procurement for June 23, 2016.

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150 IPA 2016 Electricity Procurement Plan at 4 (Sept. 28, 2015).

151 ICC Docket No. 15-0541, Final Order (Dec. 16, 2015).

Appendix B. Historical Relative Cost Comparison

Table B-1: Relative Cost Comparison of RECs and Electricity under Contract to ComEd in the 2014-15 Delivery Year

Cost of RECs and Electricity Under Contract for Delivery to ComEd in the 2014-15 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
REC Purchases, 2010 Long-Term Purchase Agreements[152]	1,261,725	RECs	$18.38	$23,190,506
REC Purchases, 2012 Rate Stability	623,577	RECs	$1.65	$1,027,243
Total RECs	1,885,302	RECs	$12.85	$24,217,749
Long-Term Renewable Energy, 2010 Long-Term Purchase Agreements[153]	1,261,725,	MWh	$39.03	$49,244,208
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2014 Spring Block Energy Procurement	5,914,000	MWh	$38.18	$225,770,460
2014 September Energy Procurement	3,663,400	MWh	$36.39	$133,304,668
2012 Block Energy Procurement, Rate Stability	3,942,000	MWh	$33.39	$131,623,380
2012 Block Energy Procurement, Procurement Plan	367,600	MWh	$43.11	$15,846,432
Total Conventional Energy Resources	13,887,000	MWh	$36.48	$506,544,940

[152] This represents the Annual Contract Quantity Commitment of RECs specified in the contract and not quantities of RECs delivered to date in the 2014-15 delivery year. There were 34,106 Carry-Over RECs delivered in the 2013-14 delivery year that will be applied toward the 2014-15 delivery year Annual Contract Quantity Commitment.

[153] This represents the energy associated with the Annual Contract Quantity Commitment of RECs specified in the contract and not volumes of energy associated with RECs delivered to date in the 2014-15 delivery year. There were 34,106 MWh of energy associated with Carry-Over RECs delivered in the 2013-14 delivery year that will be applied toward the 2014-15 delivery year Annual Contract Quantity Commitment.

Table B-2. Relative Cost Comparison of RECs and Electricity Delivered to ComEd in the 2013-14 Delivery Year

Cost of RECs and Electricity Delivered to ComEd for the 2013-14 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity[154]**		**Average Unit Price**	**Amount Spent**
REC Purchases, 2010 Long-Term Purchase Agreements[155]	900,087	RECs	$18.29	$16,464,933
REC Purchases, 2012 Rate Stability	1,339,909	RECs	$1.28	$1,714,615
Total RECs	2,239,996	RECs	$8.12	$18,179,202
Long-Term Renewable Energy, 2010 Long-Term Purchase Agreements	900,080	MWh	$38.58	$34,728,798
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2012 Block Energy Procurement, Rate Stability	3,942,000	MWh	$32.57	$128,390,940
2011 Block Energy Procurement	12,555,600	MWh	$37.51	$470,917,380
Total Conventional Energy Resources	16,497,600	MWh	$36.33	$599,308,320

[154] According to ComEd, "small differences between REC amounts and Energy amounts [associated with the 2010 LTPPAs] are due to rounding since RECs delivered each month are in whole integers and Energy is calculated out to .001 MWhs."

[155] RECs delivered may include Carry-Over and Short-Fall RECs that reflect year to year delivery fluctuations.

Table B-3. Relative Cost Comparison of RECs and Electricity Delivered to ComEd in the 2012-13 Delivery Year

Cost of RECs and Electricity Delivered to ComEd for the 2012-13 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**[156]		**Average Unit Price**	**Amount Spent**
REC Purchases, 2010 Long-Term Purchase Agreements[157]	1,205,267	RECs	$17.30	$20,848,772
REC Purchases, 2012 Procurement Plan	1,335,673	RECs	$0.88	$1,175,392
Total RECs	2,540,940	RECs	$8.67	$22,024,164
Long-Term Renewable Energy, 2010 Long-Term Purchase Agreements	1,205,266	MWh	$38.04	$45,844,618
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2012 Block Energy Procurement	411,600	MWh	$30.58	$12,587,388
2011 Block Energy Procurement	1,486,400	MWh	$44.55	$66,216,080
Total Conventional Energy Resources	1,898,000	MWh	$41.52	$78,803,468

Table B**-4. Relative Cost Comparison of RECs and Electricity Delivered to ComEd in the 2011-12 Delivery Year**

Cost of RECs and Electricity Delivered to ComEd in the 2011-12 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2011 Procurement Plan RECs	2,117,054	RECs	$0.95	$2,011,202
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2011 Block Energy Procurement	9,119,600	MWh	$36.84	$335,946,584
2010 Block Energy Procurement	2,529,200	MWh	$42.69	$107,982,124
Total Conventional Energy Resources	11,648,800	MWh	$38.11	443,928,708

[156] See note 154.

[157] See note 155.

Table B-5. Relative Cost Comparison of RECs and Electricity Delivered to ComEd in the 2010-11 Delivery Year

Cost of RECs and Electricity Delivered to ComEd in the 2010-11 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2010 Procurement Plan RECs	1,887,014	RECs	$4.88	$9,207,447
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2010 Block Energy Procurement	9,866,800	MWh	$34.43	$339,703,232
2009 Block Energy Procurement	3,430,400	MWh	$41.47	$142,256,832
Total Conventional Energy Resources	13,297,200	MWh	$36.25	$481,960,064

Table B-6. Relative Cost Comparison of RECs and Electricity Delivered to ComEd in the 2009-10 Delivery Year

Cost of RECs and Electricity Delivered to ComEd in the 2009-10 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2009 Procurement Plan RECs	1,564,360	RECs	$19.27	$30,145,217
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2009 Block Energy Procurement	13,364,000	MWh	$33.17	$443,264,460

Table B-7: Relative Cost Comparison of RECs and Electricity under Contract to Ameren in the 2014-15 Delivery Year

Cost of RECs and Electricity Under Contract for Delivery to Ameren in the 2014-15 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
REC Purchases, 2010 Long-Term Purchase Agreements[158]	600,000	RECs	$13.59	$8,154,000
REC Purchases, 2012 Rate Stability	425,366	RECs	$2.38	$1,012,540
Total RECs	1,025,366	RECs	$8.94	$9,166,540
Long-Term Renewable Energy, 2010 Long-Term Purchase Agreements[159]	600,000	MWh	$38.89	$23,332,666
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2014 Spring Block Energy Procurement	364,800	MWh	$46.06	$16,801,980
2014 September Energy Procurement	311,400	MWh	$42.57	$13,256,186
SB1652 Rate Stability 2012 Block Energy Procurement	5,694,000	MWh	$31.44	$179,019,360
Total Conventional Energy Resources	6,370,200	MWh	$32.82	$209,077,526

[158] This represents the Annual Contract Quantity Commitment of RECs specified in the contract and not quantities of RECs delivered to date in the 2014-15 delivery year. There were 17,978 Carry-Over RECs delivered in the 2013-14 delivery year that will be applied toward the 2014-15 delivery year Annual Contract Quantity Commitment.

[159] This represents the energy associated with the Annual Contract Quantity Commitment of RECs specified in the contract and not volumes of energy associated with RECs delivered to date in the 2014-15 delivery year. There were 17,978 MWh of energy associated with Carry-Over RECs delivered in the 2013-14 delivery year that will be applied toward the 2014-15 delivery year Annual Contract Quantity Commitment.

Table B-8. Relative Cost Comparison of RECs and Electricity Delivered to Ameren in the 2013-14 Delivery Year

Cost of RECs and Electricity Delivered to Ameren in the 2013-14 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
REC Purchases, 2010 Long-Term Purchase Agreements[160]	482,581	RECs	$13.24	$6,391,185
REC Purchases, 2012 Rate Stability	536,020	RECs	$3.43	$1,836,736
Total RECs	1,018,601	RECs	8.08	$8,227,921
Long-Term Renewable Energy, 2010 Long-Term Purchase Agreements	482,581	MWh	$38.43	$18,546,157
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2012 Block Energy Procurement, Rate Stability	5,694,000	MWh	$29.51	$168,029,940
2011 Block Energy Procurement	5,466,800	MWh	$34.83	$190,426,316
Total Conventional Energy Resources	11,160,800	MWh	$32.12	$358,456,256

[160] RECs delivered may include Carry-Over and Short-Fall RECs that reflect year to year delivery fluctuations.

Table B-9. Relative Cost Comparison of RECs and Electricity Delivered to Ameren in the 2012-13 Delivery Year

Cost of RECs and Electricity Delivered to Ameren in the 2012-13 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
REC Purchases, 2010 Long-Term Purchase Agreements[161]	513,940	RECs	$12.29	$6,316,618
REC Purchases, 2012 Procurement Plan	523,376	RECs	$1.15	$600,269
Total RECs	1,037,316	RECs	$6.67	$6,916,887
Long-Term Renewable Energy, 2010 Long-Term Purchase Agreements	513,940	MWh	$37.92	$19,489,407
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2012 Block Energy Procurement	612,000	MWh	$27.78	$17,003,992
2011 Block Energy Procurement	3,448,400	MWh	$35.79	$123,421,404
2010 Block Energy Procurement	2,292,400	MWh	$35.06	$80,371,656
Total Conventional Energy Resources	6,352,800	MWh	$34.76	$220,797,052

Table B-10. Relative Cost Comparison of RECs and Electricity Delivered to Ameren in the 2011-12 Delivery Year

Cost of RECs and Electricity Delivered to Ameren in the 2011-12 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2011 Procurement Plan RECs	952,145	RECs	$0.92	$878,354
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2011 Block Energy Procurement	3,856,800	MWh	$32.28	$124,506,944
2010 Block Energy Procurement	3,424,400	MWh	$35.69	$122,209,912
Total Conventional Energy Resources	7,281,200	MWh	$33.88	$246,716,856

[161] See note 160.

Table B-11. Relative Cost Comparison of RECs and Electricity Delivered to Ameren in the 2010-11 Delivery Year

Cost of RECs and Electricity Delivered to Ameren in the 2010-11 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2010 Procurement Plan RECs	860,860	RECs	$4.05	$3,482,964
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2010 Block Energy Procurement	4,888,000	MWh	$31.31	$153,039,096
2009 Block Energy Procurement	4,139,200	MWh	$39.68	$164,239,360
Total Conventional Energy Resources	9,027,200	MWh	$35.15	$317,278,456

Table B-12. Relative Cost Comparison of RECs and Electricity Delivered to Ameren in the 2009-10 Delivery Year

Cost of RECs and Electricity Delivered to Ameren in the 2009-10 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2009 Procurement Plan RECs	720,000	RECs	$15.86	$11,419,200
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2009 Block Energy Procurement	6,109,600	MWh	$33.04	$201,840,356

Appendix C. Historical Rate Impacts and Total Dollar Impacts

Table C-1: ComEd Rate Impact - Calculated Bill Impacts by RECs[162]

Customer Class	Description	2009-10 Delivery Year	2010-11 Delivery Year	2011-12 Delivery Year	2012-13 Delivery Year	2013-14 Delivery Year
Single Family No Electric Space Heat	Revenue/kWh	$0.118	$0.132	$0.132	$0.128	$0.108
	REC/kWh	$0.000768	$0.000258	$0.000064	$0.001152	$0.001800
	Ratio (REC/Revenue)[163]	0.65%	0.20%	0.05%	0.90%	1.67%
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	$0.001800
	Ratio (REC/Revenue)	0.57%	0.17%	0.04%	0.81%	1.47%
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	$0.001900
	Ratio (REC/Revenue)	0.61%	0.19%	0.05%	0.59%	2.25%
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	$0.002000
	Ratio (REC/Revenue)	0.76%	0.24%	0.05%	1.08%	2.11%

[162] Overall bill (e.g. Revenue/kWh) includes fixed supply charges, PJM services charges, delivery services charges (customer charge, standard metering service charges, 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.

[163] 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.

Table C-2: ComEd Total Dollar Impact[164]

Customer Class	Description	2009-10 Delivery Year	2010-11 Delivery Year	2011-12 Delivery Year	2012-13 Delivery Year	2013-14 Delivery Year
Single Family No Electric Space Heat	Usage (kWh)	24,195,356,771	25,557,124,031	19,465,098,302	12,843,203,500	6,345,420,910
	Dollar Impact	$18,582,034	$6,593,738	$1,245,766	$14,795,370	$11,421,758
Multi Family No Electric Space Heat	Usage (kWh)	4,837,665,365	5,384,174,419	4,178,671,736	3,041,118,982	1,218,371,654
	Dollar Impact	$3,715,327	$1,389,117	$263,256	$3,500,328	$2,193,069
Single Family With Electric Space Heat	Usage (kWh)	881,222,892	506,129,412	645,304,684	546,220,195	407,285,628
	Dollar Impact	$438,849	$86,042	$27,103	$302,606	$773,843
Multi Family With Electric Space Heat	Usage (kWh)	1,860,212,425	984,758,824	1,361,870,329	991,185,128	623,631,143
	Dollar Impact	$928,246	$167,409	$58,560	$547,134	$1,184,899
Watt-hour	Usage (kWh)	588,208,974	578,444,444	392,413,102	210,947,790	99,782,219
	Dollar Impact	$458,803	$156,180	$23,545	$261,575	$199,564
Small Load (< 100 kW)	Usage (kWh)	9,766,981,818	8,912,892,593	6,005,560,303	4,701,423,060	4,015,484,746
	Dollar Impact	$7,520,576	$2,406,481	$360,334	$5,688,722	$8,030,969

[164] For Delivery Years 2011 and 2012, 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. For Delivery Years 2013 and 2014, Usage values were reported by ComEd. Dollar Impact values for Delivery Years 2011, 2012, 2013 and 2014 were calculated by multiplying the Usage by the REC/kWh reported in Table C-1. For Delivery Years 2009 and 2010, the "switching statistics" did not provide this amount of customer class detail; Dollar Impacts values for those years in 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 C-1.

Table C-3: Ameren Rate Impacts[165]

Customer Class	Description	2009-10 Delivery Year	2010-11 Delivery Year	2011-12 Delivery Year	2012-13 Delivery Year	2013 -14 Delivery Year
Residential Service	Revenue/kWh	$0.104	$0.107	$0.108	$0.104	$0.087
	REC/kWh	$0.000645	$0.000211	$0.000058	$0.000669	$0.001466
	Ratio (REC/Revenue)[166]	0.62%	0.20%	0.05%	0.65%	1.68%
Small General Service	Revenue/kWh	$0.111	$0.108	$0.107	$0.102	$0.085
	REC/kWh	$0.000645	$0.000211	$0.000058	$0.000669	$0.001466
	Ratio (REC/Revenue)	0.58%	0.20%	0.05%	0.66%	1.72%
General Service[167]	Revenue/kWh	$0.086	$0.084	$0.083	$0.075	$0.065
	REC/kWh	$0.000645	$0.000211	$0.000058	$0.000669	$0.001466
	Ratio (REC/Revenue)	0.75%	0.25%	0.07%	0.89%	2.26%

Table C-4: Ameren Total Dollar Impact

Customer Class	Description	2009 -10 Delivery Year	2010 -11 Delivery Year	2011-12 Delivery Year	2012-13 Delivery Year	2013 -14 Delivery Year
Residential Service	Usage (kWh)	11,113,952,386	12,099,965,649	11,038,029,446	8,263,759,490	4,499,952,187
	Dollar Impact	$7,168,499	$2,553,093	$644,621	$5,525,976	$6,597,380
Small General Service	Usage (kWh)	3,615,924,697	3,026,300,756	2,544,215,445	2,063,439,107	1,817,935,154
	Dollar Impact	$2,332,271	$638,549	$148,582	$1,379,822	$2,665,275
General Service[168]	Usage (kWh)	1,240,657,248	623,518,977	443,840,561	304,704,282	232,672,832
	Dollar Impact	$800,224	$131,563	$25,920	$203,756	$341,122

165 A single company-wide rate is reported for Ameren.

166 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.

167 General Service (DS-3) was declared competitive in 2014 and Basic Generation Service is no longer a supply option for those customers. Therefore, Revenue and Ratio (REC/Revenue) are reported as N/A in 2015.

168 General Service (DS-3) was declared competitive in 2014and Basic Generation Service is no longer a supply option for those customers. Therefore, Usage and Dollar Impact are reported as N/A in 2015.