2013

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

3/29/2013

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IPA

ILLINOIS POWER AGENCY Pat Quinn, Governor

Anthony M. Star, Acting Director

March 29, 2013

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

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

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

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

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

Sincerely,

Anthony M. Star

Anthony M. Star
Acting Director

160 North LaSalle Street, Suite N-506, Chicago, Illinois 60601

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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

MARCH 29, 2013

I. Executive Summary and Key Findings

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

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

(C) the unused and remaining balance in the Agency Renewable Energy Resources Fund attributable to those payments.

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

<u>Ameren Illinois Company (Ameren) Procurements</u>

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

05/18/10 REC Procurement

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

05/18/11 REC Procurement

02/16/12 Rate Stability REC Procurement

05/10/12 REC Procurement

<u>Commonwealth Edison Company (ComEd) Procurements</u>

05/11/09 REC Procurement

05/18/10 REC Procurement

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

05/18/11 REC Procurement

02/16/12 Rate Stability REC Procurement

05/10/12 REC Procurement

Deliveries under some of these procurement events are for future delivery periods (i.e. beginning June 1, 2013 and later). For these, there is discussion of the costs. However, only those procurements that have resulted in delivery under historic periods are analyzed in terms of specific rate impacts. This is because future rates are not known until all of the laddered underlying energy purchases are made for those future delivery periods and factored into future utility supply charges.

Key Findings

- In the ComEd territory, the cost of purchasing renewable energy resources ranged from a high of 1.927 cents per kilowatt-hour in the IPA's first procurement in 2009 to a low of 0.088 cents per kilowatt-hour in the 2012 procurement. The current price trend for renewable energy credits has been downward. The Agency also procured long-term power procurement agreements on behalf of ComEd in 2010 which included an implied REC price near the high end of the range described. The purchases represent a low of 0.05% to a high of 0.90% of the total rates paid for electricity by single family homes without electric space heat[1]. In the Ameren territory, the cost of purchasing renewable energy resources ranged from a high of 1.586 cents per kilowatt-hour in the 2009 procurement to a low of 0.092 cents per kilowatt-hour in the 2011 procurement. While the price trend for renewable energy credits was downward through 2011, the REC price in the 2012 procurement was about 50% higher than in 2011. The Agency also procured long-term power procurement agreements on behalf of Ameren in 2010 which included an implied REC price near the high end of the range described. Purchases represent a low of 0.05% to a high of 0.61% of the total rates paid for electricity by residential customers.

- Wind and solar power are dependent on uncertain and unpredictable energy sources – wind and sun – and there is concern that as the fraction of electricity supplied by intermittent generators grows, additional resources or more complex control systems will be needed to maintain the stability and reliability of the power system. There have been a number of studies of these "renewable integration costs"; estimates provided in studies reviewed for this report range from \$1/MWh to \$12/MWh.[2] The studies generally do not account for changes that may be made to market structures to allow for more efficient response to intermittency. Much of the variability of intermittent resources is predictable but adds complexity to the "net load shape." For example, over the last several years, MISO has been developing a "ramp capability" product to address this complexity, which may be less expensive than the ways several studies assume intermittency would be mitigated. There appears to be only minor concern over the operational impacts of penetration rates below 10% and at the integration costs listed above, there are likely solutions that can be used to address concerns that could arise at 20 to 30% penetration rates. Illinois currently has 4% of its generation from these intermittent sources, and combined with neighboring states, the level is approximately 8%.
- The Illinois Power Agency has been presented with evidence that the Illinois Renewable Portfolio Standards (RPS) appear to have enabled significant job creation and economic development opportunities as well as environmental benefits. These results cannot be extrapolated indefinitely, as factors such as market prices for energy, transmission constraints, and uncertainty in the load serving responsibility will affect the cost-effectiveness of further additions to the renewable resource generation stock in Illinois. Until the impact of retail utility load shifts from factors such as municipal aggregation can be fully assessed and addressed, Illinois utilities' capacity for further long-term contracts will be constrained.
- Renewable resources, in particular wind, have helped reduce electric energy prices in Illinois and the entire Eastern Interconnection, as measured by the impact on Locational Marginal Prices (LMPs). Modeling work commissioned by the IPA and corroborated by similar findings in Massachusetts suggests that for 2011, the integration of renewable resources into the power grid had lowered Illinois' average LMPs by \$1.30 per megawatt hour (MWh), from \$36.40 to \$35.10

[1]Rate impacts vary by customer class and are reported here for ComEd's largest customer class, Single Family Without Space Heat. For Ameren the largest customer class is Residential Service. For a full breakdown of rate impacts by customer class, see Figure 15 for ComEd and Figure 17 for Ameren.
[2] One MWh equals one thousand kilowatt-hours (kWh). MWh are typically used for wholesale transactions while kWh are used for retail transactions. Therefore the \$1/MWh to \$12/MWh range for the cost of renewables integration translates into a retail cost to consumers ranging from one tenth of a cent to 1.2 cents per kWh.

per MWh. The aggregate result could have been a savings of as much as $176.85 million in total load payment for generation in Illinois. Legacy hedge contracts serve to reduce the benefit of these LMP reductions to current utility ratepayers. In particular, when utility load is over-hedged (for instance, as a consequence of load departure), utility ratepayers are effectively selling energy and the LMP reduction detracts from their revenue. Still, this points out the magnitude of the benefits accruing to all consumers from lowered underlying electric energy cost drivers. Over time, the effect of lower LMPs due to growing renewable capacity will be reflected in procurement outcomes.

- In principle, low-cost renewable generators could undercut and offset electricity offered into the markets by coal-fired and nuclear generators, which are two important sources of electricity and capacity in Illinois and important factors in Illinois' economy. If those plants' gross energy margins were reduced, they may seek higher capacity prices to continue operation. Over the last five years, coal-fired energy has represented a declining fraction of the supply mix in MISO and PJM; however, that has generally reflected fuel economics (coal-to-gas switching) more than loss of market share to renewables.
- The Alternative Compliance Payment (ACP) mechanism is a useful construct with which to effect compliance with RPS standards in a way that is competitively neutral, because it allows an opportunity for the additional costs of renewable resources to be the same, on an average cents per kilowatt-hour (kWh) basis, regardless of whether a customer takes electricity supply from a utility or an ARES.
- The IPA included an analysis and proposal for the use of the ACP-funded IPA Renewable Energy Resources Fund (RERF) in its approved 2013 Procurement Plan.[3] Accordingly, the IPA plans to use money from the RERF fund to purchase RECs curtailed from the 2010 Long-Term Power Purchase Agreements.
- Under the Energy Infrastructure Modernization Act (EIMA), the IPA must include specific amounts of distributed generation in RERF purchases.[4] In particular, conducting parallel utility and ARES distributed generation procurements holds promise, as this is an, as yet, unfulfilled mandate. It should be noted that the minimum required term length for distributed generation contracts is 5 years. Unless the General Assembly can prevent "borrowing" from the RERF, which serves to deplete the dollars available for their legislatively stated purpose, any long-term contractual arrangements based on the flow of funds from the ACP mechanisms have risks that must be addressed.
- Legislation pending before the General Assembly proposes to do away with the ACP mechanism, and instead require the IPA to facilitate base RPS compliance for all retail electric customers regardless of supplier. This proposal removes volumetric risk from the IPA, but it may raise issues of monopsony and inefficient markets which should be further examined before adoption.

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

[4] Public Act 97-0616, amending 20 ILCS 3855/1-10, 20 ILCS 3855/1-56.

There may be mechanisms to address these concerns, but the IPA has not had the opportunity to fully and properly analyze the impact on the market of possible solutions.

II. Report Methodology

This Report draws upon publicly available data regarding electric utility load, procurement results, and ACP fund reporting. Although the RPS has been in place since June 1, 2008, the Agency was not required to conduct a renewable energy resource procurement event until 2009, for delivery beginning June 1, 2009. Given the statutory directive to examine "the Agency's procurement,"[5] this report focuses its analysis on the years 2009 through 2012. There is no specific definition of either "costs" or "benefits" in the IPA Act. For the purposes of this report, "costs" are the final amount settled for a renewable resource as publicly reported, and "benefits" are both quantitative and qualitative economic and societal impacts.

The 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.[6] For the purposes of determining the total bill impact, presented as both a percentage of an average customer bill for that class and in cents per kilowatt-hour, 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."[7]

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: www2.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 data necessary for this Report. The IPA also would like to thank PA Consulting Group, its procurement planning consultant, for its assistance in preparing this Report. Finally, the IPA acknowledges the significant and valuable contributions to this Report of its previous Acting Director, Arlene Juracek.

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

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

[7] 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 … the Agency's costs associated with electricity generated by other types of generation facilities."[8]

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

- The actual average cost of RECs procured by the Agency in that year's procurement;
- The actual average cost of energy (and for Ameren, capacity) procured by the Agency from conventional supply sources in that year's procurement; and
- The 2010 Long-Term Power Purchase Agreements (LTPPA) purchase costs broken down to show the imputed REC and energy prices[9], beginning with the June 2012 – May 2013 delivery year, which is the first year of delivery under those agreements.

With regard to the final item, note that the contracts themselves contain bundled pricing for energy and RECs. REC prices are "imputed" by subtracting an energy price from the bundled price. The energy prices used are from contemporary forward energy curves. The process of imputing these REC prices is described in Appendix K to the Agency's 2010 Procurement Plan.[10] When the Agency submitted its 2012 report on renewable resource procurement, the imputed costs were still confidential. Therefore these imputed 2010 LTPPA purchase costs differ from the costs included in the 2012 Report, which were the bundled energy and REC costs.

The RECs procured by the utilities under the 2012 Rate Stability Procurement do not begin delivery until June 2013. The price of these REC products is noted in the tables but not included in the calculations since delivery has not begun.

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

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[8] 20 ILCS 3855/1-75(c)(5)(A).

[9] In its Dec. 19, 2012 order (note 3 *supra*) the ICC allowed for the release of the previously confidential "Appendix K" imputed REC prices. The conformed plan (Ill. Power Agency, Ill. Commerce Commission Docket 12-0544, 2013 Electricity Procurement Plan Conforming to the Commission's December 19, 2012 Order at 84) included imputed prices for the five subsequent Plan Years 2013-2017.

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

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

- 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 that "the IPA is not permitted to undertake the acquisition of multi-year or long-term renewable resources."[11]
- 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.[12] The ICC additionally found that the 2010 LTPPA "will supplement the short-term REC acquisition," and approved the IPA's revised plan to enter into LTPPAs for renewable energy supplies "outside of the RPS."[13]
- 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.[14]
- 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.[15]

The IPA has recommended, and the ICC has approved[16], that there should be no new Ameren or ComEd REC procurement event in the 2013 Procurement Plan.[17]

Ameren's forecasted REC requirements for delivery beginning June 1, 2013 have been more than met by purchases under the 2010 LTPPA and the separate Rate Stability Procurement of renewable energy resources conducted in February 2012 pursuant to Public Act 97-0616.[18] These latter resources are for delivery June 1, 2013 through December 31, 2017. Their costs are indicated in this report but not their rate impacts, which are unknown at this time.

ComEd's previously purchased RECs meet the target for the June 2013 – May 2014 delivery year but its RPS budget has been exceeded for the delivery year, according to ComEd's March 15, 2013 forecast.

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

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

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

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

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

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

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

[18] Ill. Power Agency, Ill. Commerce Commission Docket 11-0660, 2012 Power Procurement Plan Updated at 60 (Feb. 17, 2012).

1. ComEd

Delivery Year	Avg. Cost of RECs Procured by IPA in the Delivery Year (¢/kWh)	Avg. Cost of Conventional Supply Procured by IPA in the Delivery Year (¢/kWh)
June 2009 – May 2010	1.927	3.281
June 2010 – May 2011	0.488	3.344
June 2011 – May 2012	0.095	3.684
June 2012 – May 2013:		
2012 Procurement Plan	0.088	3.058
2010 LTPPA Purchases	1.715[19]	3.803
Load-weighted average	0.970	3.620
June 2009 – May 2013[20]	**0.8097**	**3.422**
June 2013 – May 2014:		
2010 LTPPA Purchases[21]	1.773[22]	N/A
2012 Rate Stability[23]	0.129	3.257
Load-weighted average	1.189	3.257

Figure 1: Relative Cost Comparison of RECs and Conventional Supply on a Cent per Kilowatt-hour Basis for ComEd[24]

[19] Imputed.

[20] Load-weighted average.

[21] The entire contract term is June 2012 – May 2032. *See* ICC Approves Results of Renewable Energy RFP, News from the Ill. Commerce Commission (Dec. 15, 2010).

[22] Imputed.

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

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

2. Ameren

Delivery Year	Avg. Cost of RECs Procured by IPA in the Delivery Year (¢/kWh)	Avg. Cost of Conventional Supply Procured by IPA in the Delivery Year[25] (¢/kWh)
June 2009 – May 2010	1.586	3.682
June 2010 – May 2011	0.405	3.114
June 2011 – May 2012	0.092	3.234
June 2012 – May 2013:		
2012 Procurement Plan	0.137	2.863
2010 LTPPA Purchases	1.256[26]	3.788
Load-weighted average	0.881	3.321
June 2009 – May 2013[27]	**0.6908**	**3.398**
June 2013 – May 2014:		
2010 LTPPA Purchases[28]	1.303[29]	N/A
2012 Rate Stability[30]	0.343	2.951
Load-weighted average	0.850	2.951

Figure 2: Relative Cost Comparison of RECs and Conventional Supply on a Cent per Kilowatt-hour Basis for Ameren[31]

3. Costs of intermittency

According to statistics published by the U.S. Energy Information Administration, in 2012 Illinois' electric power sector ranked fifth among the states in wind production (Figure 3). Wind and solar power are dependent on uncertain and unpredictable energy sources – the wind and sun – and there is some

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

[26] Imputed.

[27] Load-weighted average.

[28] The entire contract term is June 2012 – May 2032. *See* ICC Approves Results of Renewable Energy RFP, News from the Ill. Commerce Commission (Dec. 15, 2010).

[29] Imputed.

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

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

concern that as the fraction of electricity supplied by intermittent generators grows, additional resources or more complex control systems will be needed to maintain the stability and reliability of the power system.

	State	2012 Generation from Wind (GWh)
1	Texas	31,860
2	Iowa	13,941
3	California	9,936
4	Oklahoma	8,233
5	**Illinois**	**7,708**
6	Minnesota	7,506
7	Washington	6,687
8	Oregon	6,065
9	Colorado	6,031
10	North Dakota	5,316

*Source: U.S. Energy Information Administration, **Electric Power Monthly**, Feb. 25, 2013*

Figure 3. Top Ten wind generating states, 2012

Although Illinois produced a large amount of wind energy in an absolute sense, this was still a small fraction (4%) of its total 2012 production (the statutory RPS standard, which is 8% by June 1, 2013, is based on the ratio of renewable supply to total retail supply for each utility individually; the ratio of in-state renewable production to total in-state renewable production is used for comparability with available data for other states). In order for intermittent generation to have a noticeable operational impact on the power system, it should represent a sizable fraction of total generation. That fraction indicates the intermittent penetration. Figure 4 shows the states with the largest intermittent penetrations in 2012. None of the first 11 states in this table generated more than 80,000 GWh in 2012 -- the largest among them, Oklahoma, ranked 18th among the states in net generation.

	State	2012 Intermittent Generation (GWh)	2012 Net Generation (GWh)	Penetration (Ratio)
1	Iowa	13,941	54,647	25.5%
2	South Dakota	2,914	12,168	23.9%
3	Minnesota	7,506	50,777	14.8%
4	North Dakota	5,316	36,013	14.8%
5	Idaho	1,821	15,663	11.6%
6	Colorado	6,188	53,503	11.6%
7	Kansas	5,119	44,758	11.4%
8	Oklahoma	8,233	77,462	10.6%
9	Oregon	6,065	59,870	10.1%
10	Wyoming	4,394	48,607	9.0%
11	Maine	884	9,837	9.0%
12	Texas	32,001	388,604	8.2%
13	New Mexico	2,562	36,412	7.0%
14	California	11,303	182,919	6.2%
15	Washington	6,688	114,618	5.8%
16	Montana	1,238	27,718	4.5%
17	**Illinois**	**7,745**	**194,558**	**4.0%**
18	Hawaii	367	9,413	3.9%
19	Nebraska	1,275	34,293	3.7%
20	Indiana	3,161	111,316	2.8%

*Source: U.S. Energy Information Administration, **Electric Power Monthly**, Feb. 25, 2013*

Figure 4. Top twenty states by intermittent penetration (ratio of intermittent to net generation), 2012

This should imply that intermittent generation is not a large enough part of the total in Illinois to impact system operations. However, Illinois is interconnected with its neighboring states, and Illinois utilities are part of the PJM and MISO RTOs. The nearby states of Iowa and Minnesota rank first and third in renewable penetration. Considering Illinois together with its neighboring states of Wisconsin, Minnesota and Iowa, the collective renewable penetration is 8.5% (Figure 5). This is a large enough penetration to create concerns about additional operational costs associated with intermittency. Independent studies reviewed below indicate that such concerns may arise at penetration levels above 10%.

State	2012 Intermittent Generation (GWh)	2012 Net Generation (GWh)	Penetration
Illinois	7,745	194,558	4.0%
Iowa	13,941	54,647	25.5%
Wisconsin	1,546	62,224	2.5%
Minnesota	7,506	50,777	14.8%
TOTAL	30,738	362,206	8.5%

Figure 5: Renewable penetration in Illinois combined with its northern and western neighbors

The remainder of this section III.A summarizes a number of recent studies aimed at characterizing and estimating the operational costs associated with increased penetration of intermittent renewables (also referred as integration or intermittency costs). All these studies have been collected from publicly available literature.

In addition, insights on renewable integration and intermittency costs were sought from multiple industry experts. Experts at several U.S. utilities and in Europe were interviewed, and the study also leverages the knowledge and experience of a senior European consultant on the German wind energy market.

This review focuses on:

- The operational impacts of integrating intermittent renewables (wind and solar energy) into the power system
- Actions that could be taken to address or mitigate those impacts
- Attempts to estimate the additional operation costs associated with increased penetration of intermittent renewables.

This review is based on publicly available literature. A list of and details on the studies reviewed is provided in the Appendix.

Impacts and Cost Estimates of Renewables Intermittency

1) Intermittency Impacts Addressed in the Current Literature

The challenges associated with the integration of intermittent renewables are numerous and diverse. This section's primary objective is to list impacts which have been identified in the literature and provide details on the associated challenges.

Impacts can be categorized as follows:

- Impact on the system's load and generation
- Impact on the system's flexibility
- Changes in system reliability requirements
- Impact on scheduling and forecasts

- Impact on transmission requirements
- Impact on economic investment.

The following are detailed examples of intermittency impacts organized based on the above categorization.

Impact on the system's load and generation

Load following impact - Load following is the ability of the system to respond to fluctuations in demand or generation. The variability of wind and solar plants' output will significantly impact the system's load and may require more frequent and intensive ramping from existing and new thermal power plants. “Variability” here does not necessarily mean “unpredictability”. ISOs often refer to this requirement as “flexible ramping”.

Generation regulation impact - Generation regulation refers to a power plant's ability to adjust its generation within a very short timeframe, generally without human intervention, in order to maintain the desired system frequency. Short-term fluctuations in wind and solar generation will therefore increase the need for and importance of fast-responding regulation capacity.

Overgeneration impacts - Overgeneration occurs when there is more supply from non-dispatchable resources (such as coal and nuclear capacity at minimum loading) than there is demand. This situation is more likely at night, when the output of wind turbines is large therefore displacing some conventional generation (usually coal power plant generation). Overgeneration will trigger the need for the generation fleet to operate longer at lower minimum operating levels and provide more frequent starts, stops and cycling. Some base load generators may also be required to operate at lower capacity factors to compensate for the increased output from wind turbines. Overgeneration will very likely result in energy revenue losses for conventional generators.

Impact on the system's flexibility

Impact on the existing capacity and ramp-up and ramp-down capabilities of on-line flexible generation - The intermittent nature of wind and solar energy requires increased flexibility from dispatchable generation, and this includes quicker ramp-up and ramp-down capabilities of thermal (primarily natural gas peaking units) and hydro power plants. Furthermore, the need for flexible generation will increase with the penetration level of wind and solar energy.

Changes in conventional generation dispatch - Wind and solar generation has a significant impact on conventional generation dispatch. U.S. focused renewable integration studies (such as the WSIS and the EWITS) show that wind and solar primarily displace gas fired and, to a less extent, coal generation at approximately 30% renewable penetration level (as a percentage of annual energy load). This is primarily noticeable at night, when wind generation is at its peak. As noted below, current gas price forecasts are below those used in the two named studies, and with those prices the same models might show wind and solar displacing coal rather than gas generation.

In some extreme cases (as during Christmas 2012 in Germany), wind generation alone may be greater than the system load, therefore producing negative spot market prices. In that case, conventional generators may still decide to keep their units on as the costs of shutting the units down may be greater than the losses they will face in the energy market.

Impact on gas storage - This challenge is directly related to the uncertain nature of wind and solar generation. As wind and solar generation deviates from day-ahead forecasts, the daily amount of gas required for electric energy production becomes uncertain which results in additional integration costs related to gas storage.

Changes in system reliability requirements

Changes in use of hydro resources and hydro scheduling - Hydro generation's quick start/stop cycling and fast ramping capabilities represent a great opportunity to balance the intermittency of wind and solar generation. However, to effectively leverage the flexibility of hydro generation, it is necessary to change the way it is scheduled: hydro generation will have to be scheduled against net load, which is the system load minus wind and solar generation, rather than the total system load. Due to the geography of the Midwest, hydro is not a significant factor for Illinois.

Impact on scheduling and forecasts

Impact of wind forecast alternatives - Intermittent renewable generation is dependent on weather conditions and it is therefore essential to integrate day-ahead wind and solar forecasts into the power plant commitment process.

Changes to address contingency reserve shortfalls or wind curtailment risks due to extreme wind forecast errors - Wind forecast errors can be significant in some hours of the day, leading to contingency reserve shortfalls in case of over-forecasts or wind curtailment in case of under-forecasts. Addressing the contingency reserve shortfall challenge may involve additional commitment of spinning reserves (which could be a costly solution) and/or the development of demand response programs.

Impact on transmission requirements

Impacts on the transmission system - High quality wind or solar resources are very often remote from the load centers, therefore requiring new transmission capacity. The development of new transmission capacity constitutes one of the key recommendations of the EWITS study, which states that new transmission will be required in the Eastern Interconnect for all the scenarios considered in the study. This study also demonstrates that substantial curtailment of wind generation will be required at a 20% renewable penetration level if no transmission improvements are implemented. Since it takes longer to build new transmission capacity than new power plants, prompt and effective transmission planning becomes essential with increasing level of renewables penetration.

As described, these transmission costs are attributable to renewable portfolio standards or to the desire for additional renewable energy. They are not all necessarily attributable to the *intermittency* of that renewable energy, but some fraction of the costs are so attributable. A transmission line that collects intermittent renewable resources may have to be larger and more expensive than a line that collects conventional energy, because it accesses generation that has characteristically lower capacity factors. It is also true that more remote "higher quality" renewable resources are often more persistent and less intermittent than local resources, but it can be difficult to attribute an appropriate share of transmission costs to the intermittency.

Impact on economic investment

Changes in conventional generators revenues and profits - The integration of renewables has two large impacts on thermal generators revenues:

- The low variable costs of wind and solar energy drives Locational Market Prices (LMPs) down
- Wind and solar generation displace thermal power plants generation.

These two effects reduce the margins available to cover fixed costs. Furthermore, the additional flexibility required from conventional generation (more frequent and more rapid ramping and cycling as well as operation at lower generation levels) and the additional wear and tear which will result from it, will trigger an increase in capital and O&M costs.

The combination of revenue losses and additional costs may severely impact the profit margins of conventional generators. It may not be possible to maintain adequate levels of capacity, and to commit sufficient ramping capacity to cover generation fluctuations, without increase in capacity and ancillary service payments.

2) Overview of Potential Mitigation Actions

Multiple intermittency cost mitigation actions have been considered in the studies reviewed. These mitigation actions are summarized in this section in order to portray the options that may be available to the IPA, system operators, generators, and other stakeholders to reduce the cost of intermittency. However, they do not constitute specific recommendations endorsed by the IPA at this time. These actions can be grouped in to the following categories:

- Increased collaboration between Balancing Authorities
- Increased flexibility from conventional generators
- Operational and interconnection requirements on new intermittent capacity
- Improved forecasting and scheduling
- Increased levels of demand response
- Improved reliability.

Note that most of the cost associated with the second, third and sixth categories (increased flexibility, operational and interconnection requirements on new intermittent capacity and improved reliability) can be directly attributed to intermittent renewable integration. Actions in the other three categories respond to other needs and policy choices as well, and their costs should only be partially attributed to intermittent generation.

Increased collaboration between Balancing Authorities

Increased cooperation and/or consolidation of balancing areas – Multiple studies discussed the need for balancing area cooperation and/or consolidation as an action to mitigate intermittency costs. A better balancing cooperation would enable the aggregation of load and renewable resources over larger geographic areas (therefore reducing their overall variability) and the aggregation of conventional resources (therefore providing more flexibility to the system). Admittedly this particular action may not make much difference to Ameren Illinois or ComEd, as both are already in large ISO balancing areas (MISO and PJM, respectively).

Improved cooperation between balancing areas may also lead to a more efficient use of the existing transmission network (i.e. fully utilize the current transmission capacity), the development of new transmission capacity or both.

Increased flexibility from conventional generators

Alternative generation mix – The intermittent nature of wind and solar energy requires fast ramping and cycling capabilities for generation regulation and load following. Replacing part of the current conventional base load generation by fast-response turbines should provide additional flexibility to the system. Alternatively, base load capacity could be modified to become more flexible. Multiple studies have also investigated the development of pumped storage capacity; however, the EWIS study emphasizes the need to build pumped storage where it is cost-effective to do so, i.e. where capital costs remain low.

Optimized resource planning - When developing resource plans, it will become essential to ensure that enough flexibility will be built into the system to ensure a smooth integration of intermittent renewables. This will require that current market stakeholders and generators planning for new capacity be provided with clear and accurate information regarding markets, pricing mechanisms and interconnection standards characteristics.

Operational and interconnection requirements on new intermittent capacity

Wind and solar generation flexibility - Generators and system operators should evaluate means to obtain additional operational flexibility from wind and solar resources. The CAISO study reviewed states that "greater economic dispatch control, including curtailment and ramp rate limitations, can be used in targeted circumstances to mitigate overgeneration or shortfalls in regulation and load-following capability generally." In addition, contingency reserves may be built-in into wind and solar power plants. For instance, the delivery capacity of a photovoltaic plant could be held below its total panel capacity (by undersizing the inverters or other interconnection equipment) and it would therefore appear more reliable thanks to its lower rated capacity.

Interconnection requirements - Many ISOs are currently developing (or have already developed) interconnection standards to ensure that wind and solar power plant design and performance contribute to the system's reliability.

Operator awareness and practices - As with any other power plants, wind and solar generation should be visible and controllable by the system operator. The EPRI study states that the New York Independent System Operator (NYISO) "already has developed a FERC-approved wind resource management proposal that makes wind plants subject to dispatch signals when system constraints exist." Similar schemes to dispatch or curtail based on ISO wind forecasts, or in case of congestion, have been developed by other ISOs.

Optimized scheduling/forecasting

Use of the state-of-the-art forecasts - Weather forecasts should be part of the system scheduling as wind and solar generation is directly related to weather conditions. This should reduce the amount of energy shortfalls and ultimately the system operational costs. Even though wind and solar forecasts are imperfect they can yield large savings: the WWSIS study reports a reduction of up to 14% (or $4 billion/year in 2009 dollars) in the WECC operating costs when using wind and solar forecasts. Assuming perfect forecasts, operating costs would drop by an additional $425M (in 2009 dollars).

Improve day-ahead and real-time forecasting - In order to improve market efficiency, system operators should develop tools to better predict the next day's hourly regulation needs (which will vary substantially due to integration of intermittent renewables). Such tool could be based on historical data and probabilities of wind and solar generation.

Similarly, ISOs should improve the forecasting of load following requirements by using a sub-hourly basis. The CAISO states that such capability "could be complemented by an evaluation of whether to modify unit commitment algorithms and procedures to reflect those forecast ramp (load following) requirements". Sub-hourly scheduling is also expected to decrease reserve requirements.

Switch from hourly scheduling to sub-hourly scheduling - Currently, generation and interstate exchange are scheduled on an hourly basis which conflicts with the variability associated with wind and solar generation. The WWSIS study demonstrates that "sub-hourly scheduling can substantially reduce the maneuvering duty imposed on the units providing load following". Consequently, sub-hourly scheduling should lead to an increase in power plant efficiency and a decrease in their O&M costs.

Decrease the amount of self-scheduled capacity - Some generators can self-schedule their own power plants to serve their own customers' demand. Consequently, this self-scheduled capacity cannot be used for load following purposes. With increasing needs for system flexibility and load following capabilities, the level of self-scheduled capacity should be limited. Incentives to reduce the level of self-scheduling may involve price or supply guarantees to the owners of those resources.

Increased levels of demand response

Develop demand response programs - The objective of demand response programs is to align customer's demand with supply conditions. Demand response can therefore be used to accommodate the variability and uncertainty of intermittent renewables. Multiple studies have referred to demand response as being a cost effective tool to reduce contingency reserves shortfalls: the WWSIS concluded that it is more cost-effective to use demand response to address contingency reserve shortfalls than committing additional spinning reserves.

Development of electric vehicles (EVs) - As stated previously, wind generation is at its peak at night and overgeneration may occur during hours when the demand on the system is low. To mitigate the risks of overgeneration, system operators can either curtail conventional or wind generation. An alternative solution could be to increase the load by providing incentive to electric and/or plug-in hybrid electric vehicle (EVs and PHEVs) owners to charge their batteries at night. However, the impact of EVs and PHEVs on the system is directly related to their market penetration, which is expected to remain limited in the next five to ten years.

Improved Reliability

Additional reserve requirements - Ensuring the system's reliability while integrating large amount of intermittent renewables may require additional reserve requirements and storage capacity (such as pumped storage). However, the WWSIS demonstrates that in some cases the back down of conventional generation (necessary to balance the additional renewable generation) would result in more available up-reserves, and concludes that the commitment of additional reserves may not be necessary to ensure reliability.

3) *Intermittency Cost Estimations*

The intent of this section is to present intermittency cost estimates which have been included in the studies reviewed. The intermittency costs correspond to the costs incurred by the system for the accommodation of the variability and uncertainty associated with intermittent renewables. These costs are generally estimated by comparing the system production costs associated with a scenario which includes wind and/or solar capacity to the productions costs associated with a no-renewables scenario. These estimates are gathered in Figure 7 and Figure 8.

A review of the current literature shows that estimated integration costs are dominated by:

- New transmission capacity costs (when needed)
- Increase in balancing costs due to greater flexibility needs to accommodate intermittent renewables
- Cost of additional commitment of spinning reserves and for longer periods of time
- O&M costs related to additional wear and tear for existing thermal capacity (due to increased ramping and cycling).

There are significant differences between the various studies' cost estimates. These changes may be due to different:

- Assumptions about the penetration level of intermittent generation
- Fuel price assumptions (natural gas prices can have a significant impact on integration costs as discussed in the next section)
- Sizes and structures of balancing areas (the areas within which generators are scheduled and may be able to substitute for one another; larger balancing areas are more diverse and can more easily integrate additional intermittent generation)
- Available transmission capacity
- Available spinning reserve capacity.

Also, not all studies have the same level of detail or degree of peer review. Less rigorous studies may not capture as many cost components.

Figure 6 displays wind integration cost estimates extracted from multiple studies (completed between 2003 and 2011, not including all the recent studies reviewed herein) given several wind penetration levels. The lowest integration cost estimate is slightly below $1/MWH for a wind penetration of less than 2% (as a percentage of the system peak load) while the highest estimate is approximately $11/MWh for a 20% penetration level. This chart shows most of the estimates being within a $2/MWh to $7/MWh range.

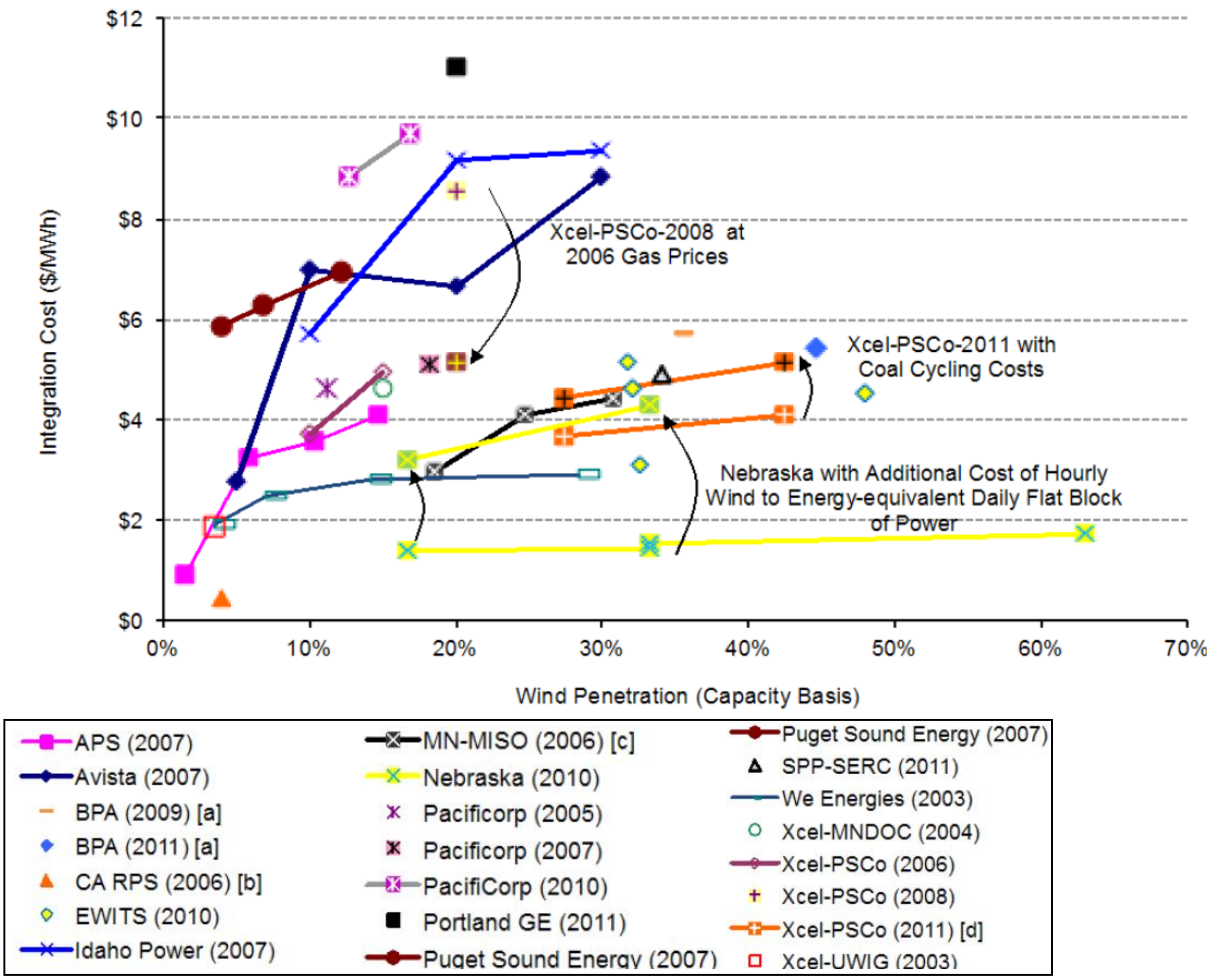


Figure 6: Integration costs at various levels of wind power capacity penetration, from DOE's 2011 Wind Technologies Market Report

Source: U.S. DOE, 2011 Wind Technologies Market Report

Figure 7 and Figure 8 provide estimates of various components of the cost of intermittency, as well as some characterizations of the total costs, from six of the key studies reviewed here, one of which is the source of Figure 6.

While studies providing integration cost estimates are numerous, some intermittency cost components are yet to be quantified (or at least were not quantified in the studies reviewed):

- Allocated share of the costs of actions that also address other needs and policy choices (demand response programs, enhanced cooperation of balancing authorities, better wind and solar energy scheduling and forecasting)
- Costs of fuel and emissions due to inefficient operation during cycling and ramping compared to steady-state operation
- Compensation to thermal power plants for the loss of energy revenues (due to the drop in energy market prices and capacity factors).

	Studies		
Cost Component	WSIS	EWITS	PacifiCorp's IRP
Capital Costs	- New wind capital costs = $2000/kW - New transmission capacity costs = $1600/kW - Transmission losses = 1% per 100 miles	- New wind capital costs = $1875/kW (2008$, onshore), $3700/kW (2008$, offshore) - New transmission capacity costs = range from $1.9M/mile to $16.0M/mile depending on location and voltage	
Average Wind Integration Cost Due to Additional Regulation/Balancing Requirements			- Cost of Interhour/System Balancing: $0.36/MWh
Average Additional System Operations Wind Integration Cost	- Cost of additional commitment of spinning reserves and for longer periods of time: increasing the committed spinning reserve by 5% of the wind forecast increases WECC operating costs by over $3,000 per MWh ($2,550/MWh in 2009$) of reduced reserve shortfall. - O&M costs related to additional wear and tear for existing thermal capacity (due to increased ramping and cycling) and/or costs associated with potential increased EFORd and degraded performance over time: at 30% renewable penetration (as a percentage of annual load energy): $150M-$450M range when compared to scenario with no renewables	- Integration costs due to variable reserve: ranges from $2.93/MWh to $5.74/MWh depending on scenario considered - Integration costs due to day ahead forecast error: range from $2.26/MWh to $2.84/MWh depending on scenario considered	- Cost of additional hourly operating reserves: $1.52/MWh
Total Integration Costs		Ranges from $5.77/MWh to $8/MWh depending on scenario considered	

Figure 7. Estimates of intermittency costs

	Studies		
Cost Component	**EPRI's Study**	**Xcel Energy's Study**	**2011 U.S. DOE Wind Technologies Market Report**
Capital Costs			- Recent turbine transactions are reported in the $900-$1270/kW range, depending on the technology ($1150-$1350/kW range in 2011). - The capacity-weighted average installed project cost of large wind projects was nearly $2100/kW in 2011
Average Wind Integration Cost Due to Additional Regulation / Balancing Requirements	A 2009 International Energy Agency (IEA) study, which compared the wind integration costs from studies across Europe and North America, cited cost ranges of €0-4.00/MWh or about €0-5.62/MWh	Average Regulation Wind Integration Cost: - 1.44GW penetration = $0.10/MWh - 2GW penetration = $0.14/MWh - 3GW penetration = $0.21/MWh	
Average Additional System Operations Wind Integration Cost		Average System Operations Wind Integration Cost: - 1.44MW penetration = $2.39MWh - 2GW = $3.40/MWh - 3GW = $3.71/MWh Average Gas Storage Wind Integration Cost: - 2GW penetration = $0.14/MWh - 3GW = $0.17/MWh	
Total Integration Costs			"Wind integration costs estimated by all studies reviewed are below $12/MWh – and often below $5/MWh – for wind power capacity penetrations of up to and even exceeding 40% of the peak load of the system in which the wind power is delivered."

Figure 8. Estimates of intermittency costs (continued)

Regulation and Fuel Prices Uncertainties

There are currently a number of market uncertainties which are likely to decrease future renewables penetration levels (and particularly wind) and may decrease intermittency costs:

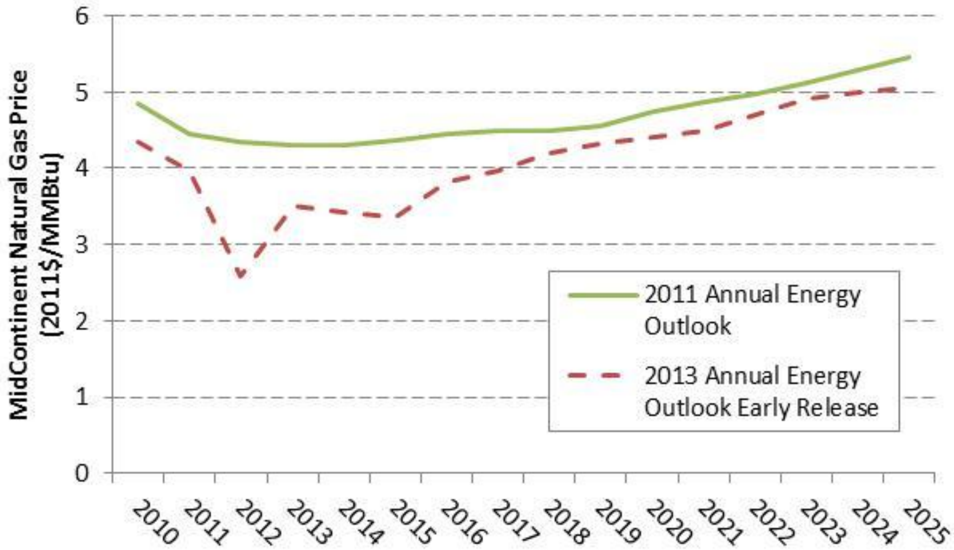
- The cancellation or renewal of the federal Production Tax Credit (PTC) incentive
- Continued low natural gas prices
- Modest demand growth.

The cancellation or renewal of the federal Production Tax Credit (PTC) incentive

Developers that generate wind, geothermal and "closed loop" energy are eligible for a Production Tax Credit which provides a $22/MWh credit to developers for the first ten years of the facility's operation. This credit accounts for approximately 20% to 30% of the current wind contract prices. The American Taxpayer Relief Act of 2012 (enacted in January 2013) extended the application of the PTC for wind energy facilities by one year, from December 31, 2012 to December 31, 2013. However, given the current economic context and the likelihood of significant federal budget cuts, an extension of the PTC beyond 2013 is uncertain. This uncertainty is reflected by the declining amount of wind capacity in interconnection queues administered by system operators in recent years.

Continued low natural gas prices

The U.S. Energy Information Administration (EIA) projects only a modest increase in natural gas prices for the next 10 to 15 years due to the development of shale gas. Furthermore, current natural gas price projections are significantly lower than the forecasts used in the studies reviewed: the WWSIS and EWITS studies assumed a natural gas price of $9.5/MMBtu in 2017 dollars and $15.7/MMBtu in 2024 dollars (for the MISO area) respectively, while the latest 2013 EIA Annual Energy Outlook projects natural gas prices of $4.6/MMBtu and $6.9/MMBtu in 2017 and 2024 (nominal dollars). The drop in natural gas prices – as illustrated in Figure 9 – will ultimately reduce the energy value of wind and solar energy; equivalently it will increase the cost of renewability (price of Renewable Energy Credits). However, it will also decrease integration costs since lower natural gas prices significantly reduce reserve requirements (which are often met by natural gas fired power plants).



Source: EIA - 2013 Annual Energy Outlook Early Release and 2011 Annual Energy Outlook

Figure 9: EIA's MidContinent natural gas price forecasts

Modest demand growth

Load growth in the ComEd and Ameren areas will remain modest in the next ten years. PJM and MISO project annual growth rates of approximately 1.6% and 0.9% in the ComEd and MISO's Central regions respectively. This modest load growth will slow down the development of thermal and renewable capacity. To meet RPS standards, the following options may have to be considered individually or collectively (and note that in Illinois, which is a restructured state, the first two options depend upon actions by independent power producers, not the utilities):

- Build new renewable capacity - This may increase the risk of overgeneration
- Curtail existing thermal generation - Conventional generators will be financially impacted and the system's flexibility may be altered
- Purchase Renewable Energy Credits (RECs).

Overall, the projected modest load growth in the Midwest could limit the need for the integration of intermittent renewable resources and therefore reduce integration costs.

Findings

This section extracts findings from the studies that are relevant to the MISO and PJM areas. The following list of findings is not intended to replace a thorough renewable integration study dedicated to Illinois but rather to provide the reader an overview of what may be the impact of a large penetration of renewables in Illinois and adjoining states.

Integration cost estimates range from less than $1/MWh to $12/MWh

The Wind Technologies Market study from the U.S. DOE reports integration cost ranging from less than $1/MWh to $12/MWh, which appears consistent with other studies' estimates.

It would not be meaningful to try to narrow down this range of estimates by averaging them, since cost estimation methodologies, wind and solar energy penetration levels, market characteristics, the studies' rigor, fuel price assumptions, etc. may vary greatly from one study to another.

However, none of the studies reviewed accounted for all the costs associated with renewable intermittency and it is therefore challenging to get an accurate view of what the total integration cost in Illinois may be. As this is important information and a focus point in all regions that have significant renewables resources, there will probably be more robust information available in the years ahead.

The EPRI study states that most power systems can reliably accommodate up to 10% wind penetration (as a percentage of annual energy load) with minor cost and operating impacts

When renewable penetration exceeds 10%, additional costs may be incurred. Most studies demonstrate that it is operationally possible to accommodate between 20% and 35% of intermittent energy (on an annual energy basis) but the associated requirements and constraints will vary significantly from one region to another:

- The EWITS study demonstrates that the Eastern Interconnect system can technically integrate between 20% and 30% of wind energy (as a percentage of annual load) but this will require a "significant expansion of the transmission infrastructure". Without transmission enhancements, significant amounts of wind generation may need to be curtailed.
- The EWITS study refers to a report published by the U.S. DOE in 2008 which assesses the costs and benefits of wind generation providing 20% of the U.S. annual total energy demand by 2030. The report showed that "although significant costs, challenges, and impacts are associated with a 20% wind scenario, substantial benefits can be shown to overcome the costs."
- The WWSIS study shows that increased cooperation between balancing authorities and sub-hourly generation and interchanges scheduling will be required for the WestConnect to accommodate up to 30% of wind and 5% of solar energy (as a percentage of annual energy load)
- Finally, the CAISO study shows that the existing generation fleet managed by the CAISO can meet the regulation and load following requirements under a 20% (as a percentage of annual energy load) RPS scenario.

Benefits due to reduced CO2 emissions and fossil fuel usage from the development of wind and solar generation are significant

Reductions in emissions and fossil fuel consumption are two of the major benefits of wind and solar generation:

- The EWIS presentation compared the reduction in operational costs due to lower emissions and fossil fuel usage to integration costs: the reduction in operational costs was estimated at EUR20B/yr while integration cost estimates were relatively small, at EUR770M
- The 30% case of the WWSIS study outlined a reduction in fuel and emissions costs of 40% and a reduction in CO_2 emissions from 25% to 45% across the WECC.

The primary challenge associated with intermittency is the magnitude and timing of ramping requirements

The studies reviewed complement insights gathered from industry experts to show that the primary challenge associated with the integration of intermittent renewables is not necessarily uncertainty but the magnitude and timing of ramping requirements.

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 … the benefits associated with the Agency's procurement of renewable energy resources."[32]

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

1. Economic Benefits

Illinois currently ranks fourth in the country for overall installed wind capacity in the U.S. with over 3.5 GW installed as of the end of 2012 according to the American Wind Energy Association (AWEA),[33] and according to the Energy Information Administration was the fifth-ranking state in total wind generation in 2012.[34] AWEA also found that Illinois ranked fifth for most new wind energy capacity installed in 2012, with 583 MW added during the year. Various categories of economic benefits are attributable to wind energy, including the impact on electricity prices, economic development, and local economies. Critics of wind energy point to factors that they assert may offset some of the purported benefits of renewable energy resources, including government subsidization of the industry, reduced land values, wear and tear on local roads during the construction of turbines, future decommissioning costs, wind energy gaining market share at the expense of coal-fired and nuclear generation, and that the variable nature of this resource could increase spinning reserve requirements.

Impact on Electricity Prices

<u>General Price Impacts</u>

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

[32] 20 ILCS 3855/1-75(c)(5)(A).

[33] *Wind Energy Facts – Illinois*, published by the American Wind Energy Association (January 2012).

[34] U.S. Energy Information Administration, "Electric Power Monthly", Feb. 25, 2013, Table I.17.B.

security.[35] Wind power can lead to more stable electricity prices, which benefit customers in the long run, by diversifying supply portfolios and softening impacts from fuel price volatility. The U.S. Department of Energy also characterizes renewable energy as a resource for hedging against risks posed by electricity price volatility, particularly through the purchase of long-term, fixed-price supply contracts for renewable energy resources directly with developers or generators.[36] (The Illinois Power Agency notes that local conditions in Illinois, especially load uncertainty due to municipal aggregation and the inexpensive prices associated with near-term RECs have pointed towards the IPA recommending the use of one-year RECs as the more cost effective alternative to meet RPS requirements at this time.) Using 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 power is 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 regional competitive wholesale markets. Power for ComEd customers flows through the transmission grid and wholesale market coordinated by PJM while Ameren is a member of MISO. Both PJM and MISO are among seven Regional Transmission Organizations (RTOs) responsible for reliable flows of energy across the nation's transmission system. The RTOs ensure that the electrical system is always perfectly balanced between supply and demand, by dispatching generation (and load reduction under some circumstances) to meet the fluctuating load. Which power plants will be used at any time to serve load is generally determined through operation of wholesale electricity markets by the RTOs.

Wholesale electric energy prices are set for hourly periods based on bidding by available generators into the regional markets. The bid of the highest cost power plant needed to satisfy the anticipated demand sets the price for the next hour's electricity. However, the actual wholesale price varies from place to place based on the additional factor of transmission congestion. Transmission congestion occurs when the lowest cost supply cannot be delivered to a demand location because of physical limitations on the capacity of the transmission line between the plant and the load center. When this occurs, other, more costly, plants with access to less constrained transmission lines are used to supply the load at that location, which increases the cost of electricity in that hour for the congested area of the system. The price at a node is known as the Locational Marginal Price (LMP). During peak periods, LMPs rise because of the combined effect of higher cost power plants being dispatched to meet system load and greater congestion in certain areas.

Construction of new generating capacity, whether renewable or non-renewable, has the effect of reducing market prices for both energy and capacity by increasing the amount of available supply. Because of their variable output, which is dependent on weather conditions, wind and solar resources

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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).

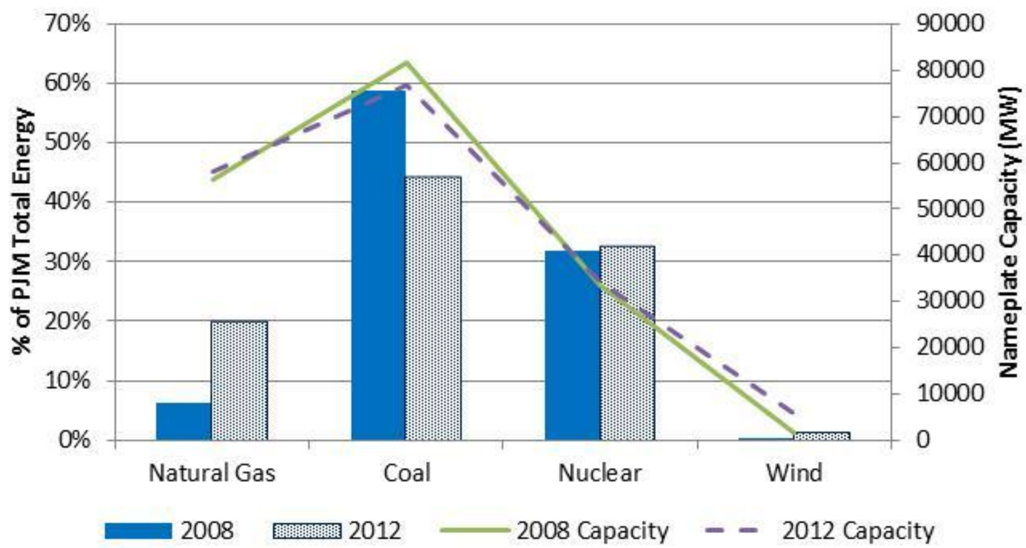
[37] *Id.*

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

have lower capacity value than dispatchable power. In PJM, the average wind capacity factor used to valuate new wind projects in the forward capacity market has been set at 13%, and solar is set at 38%, based on their projected availability during peak periods. The result is that construction of these renewable resources has a relatively small downward effect on capacity costs. However, when the sun is shining or the wind is blowing, the combined output of renewable generators benefits all customers by bringing down the market price of electric energy for all resources operating at that time. This is because wind and solar generation can effectively bid in at a zero variable fuel cost.

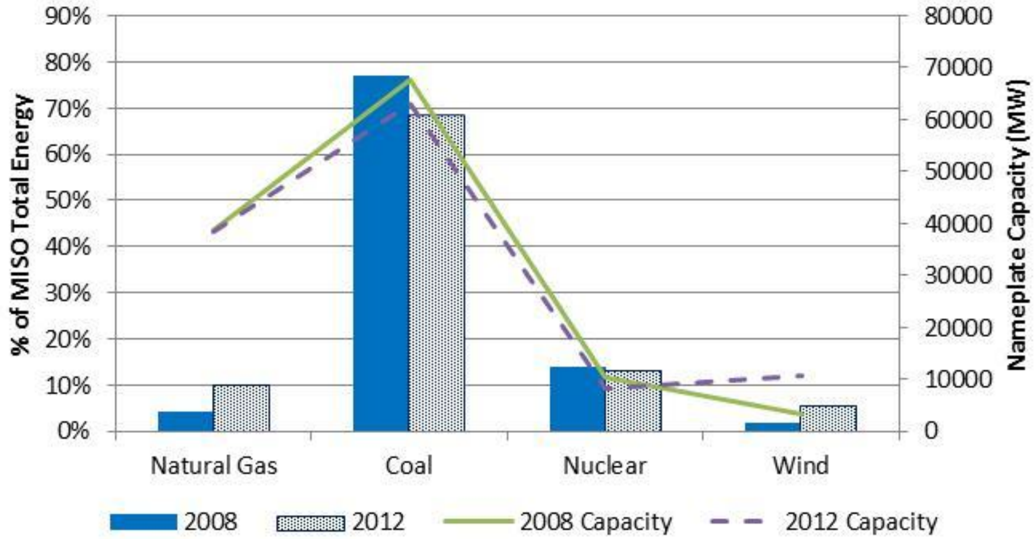
The fact that both wind and solar generators can offer their energy into wholesale electricity markets at a relatively low price has resulted in some concern that they might undercut and offset electricity offered into the markets by coal-fired and nuclear generators, two important sources of electricity and capacity in Illinois, and important factors in Illinois' economy. If those plants' gross energy margins were reduced, they may require higher capacity prices to continue operation Increases in capacity bids from other generators would probably more than counteract any reduction in capacity costs attributable to new wind plants.

To better understand the change in market dynamics over the last five years, refer to Figure 10 and Figure 11 below. These graphs display the changes from 2008 to 2012 in two different measures of the mix of electricity sources in MISO and PJM: the relative share of electric energy produced by fuel type (natural gas, coal, nuclear and wind), and the installed generating capacity by fuel type. The electric energy shares are shown as bars relative to a percentage scale on the left-hand axis, and the installed capacities are graphed as lines relative to a MW scale on the right-hand axis.



Sources: Energy Velocity and SNL

Figure 10: 2008 and 2012 PJM Energy and Capacity by Fuel Type



Sources: Energy Velocity and SNL

Figure 11: 2008 and 2012 MISO Energy and Capacity by Fuel Type

In both PJM and MISO, over the past five years electric energy produced by coal-fired plants has accounted for a lower percentage of the total electricity generated, while nuclear generation has remained stable. In both markets the drop in coal-fired generation is largely attributable to lower natural gas prices. The most efficient gas-fired generation is becoming increasingly cost-competitive with the less efficient coal-fired generators. The drop in coal-fired generation is more pronounced in PJM as there is more gas-fired generation installed there.[39]

To date the impact of electricity supplied to the PJM market by wind generators has been negligible as it only accounted for 1% of the total market generation in 2012, but in MISO that amount reached 6% in 2012. The higher proportion of wind production in MISO is largely attributable to the fact that there is more wind capacity installed in the market relative to PJM although some of the increase in MISO wind generation is a result of the implementation of the Dispatchable Intermittent Resources designation that allows registered wind resources to participate in the real-time energy market.[40] Overall, increased wind generation has offset approximately one quarter of the 8 percentage point decrease in MISO coal generation over the past five years.

The market price effects of renewable resources added to the interconnected electric system can be estimated using market modeling software. The IPA's previous procurement planning consultant, Adica, employed a proprietary market model[41] capable of modeling the entire Eastern Interconnection[42]

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

[40] MISO 2012 Winter Assessment Report

[41] MarSi is a software tool developed by GEMS for electricity market simulations which uses generator data, transmission network data, and hourly load data to model the effects of changes in fuel prices, carbon costs, wind

using data at the nodal level for both load and generation. The IPA commissioned the consultant to run the model with and without Illinois renewable generation in order to test the effect on overall LMPs for calendar year 2011.

For calendar year 2011, estimated impacts of a system with and without Illinois renewable generation are shown in Figure 12 below. The most relevant column for this report is "Total Load Payment," representing what consumers would have paid if their rates were strictly based on hourly LMPs. The model estimated that average LMPs were significantly affected by the integration of renewable resources into the power grid: it indicated that renewable resources lowered Illinois' average LMPs by $1.30 per MWh, from $36.40 to $35.10 per MWh. The aggregate result is a savings of $176.85 million in total load payment for generation in Illinois. While this does not directly translate to dollar for dollar savings in consumer bills for the same time period, due to the fact that utility consumers are served via a portfolio of resources of different vintage, it points out the magnitude of the benefits accruing to all consumers in lowered underlying electric energy cost drivers. Over time, the effect of lower LMPs due to growing renewable capacity will be reflected in procurement outcomes. Similar results were found in Massachusetts, where it has been reported that "price suppression" due to the addition of new resources provides "measurable benefits."[43]

Year	Renewable Energy Integration	Total Production Cost ($Million)	Total Generation Credit ($Million)	Total Load Payment ($Million)	System Cost Index ($Million)	Average LMP ($/MWh)	Cost of Energy Import ($Million)	Cost of Energy Export ($Million)
2011	No Renewable Energy	2,353	5,789	4,974	2,302	36.40	874	1,900
	With Renewable Energy	2,244	5,531	4,797	2,208	35.10	873	1,869

Figure 12: Estimated LMP Savings From Renewable Resource Integration[44]

and solar penetration, load growth and load growth rate, and addition/decommissioning/planned outages of generating units and transmission lines.

[42] The Eastern Interconnection includes MISO and PJM.

[43] "Recent Electricity Market Reforms in Massachusetts: A Report of Benefits and Costs," published by the Executive Office of Housing and Economic Development and the Executive Office of Energy and Environmental Affairs at 23 (July 2011).

[44] Locational Marginal Price (LMP) is the cost of supplying the next MW of load at a specific location. LMP includes the costs associated with generation, transmission, and technical losses in the system.

Production Cost comprises fuel cost, startup cost, and shutdown cost of all generating units in the system. The total fuel cost includes the cost of supplying the hourly load plus line losses. Wind and solar units do not contribute to the production cost since their fuel costs are assumed zero.

Generation Credit is the payment to all generating units in the system. The hourly generation credit of a unit is the MWh generation times the LMP at the generation bus location.

The Agency did not update this analysis using a wholesale electricity market model to gauge the impacts for the 2012 calendar year, assuming that the LMP savings would be similar. The price impact findings from the previous analysis can be applied to forecasted electricity volume requirements and procurements for eligible retail customers for the June 2012 – May 2013 delivery year in order to estimate the impact on ComEd and Ameren consumers as described in the following paragraphs and summarized in Figure 13.[45]

The wholesale market model simulates pricing in spot markets. Price reductions attributable to new capacity would not necessarily have been reflected in prices for forward contracts executed prior to the operation of that capacity, and a significant amount of Illinois renewable capacity has been recently constructed. It is therefore necessary to make an assumption as to which contract prices would have either anticipated or been affected by the LMP reductions.

For the purpose of this analysis it is assumed that energy procurements conducted since 2010 for delivery during the 2012 delivery year[46] have included the $1.30 per MWh cost savings impact of renewables integration in Illinois identified in the modeling results for the 2011 calendar year. Correspondingly, it is assumed that the price reductions were not accounted for in the swap arrangements made by ComEd and Ameren prior to 2010. The 2013 Procurement Plan forecast that ComEd and Ameren would be long energy in the latter months of Plan Year 2012 as a result of the swap arrangements and would have to sell this energy back into the market. LMP reductions would have a deleterious effect, reducing the profit or increase the loss associated with those sales (just as they would be beneficial to a short position). In essence the LMP reductions are applied to the "net short" volume, which equals the forecasted load minus the swap volume.

As indicated in Figure 13, Ameren Illinois is projected to have a net short (net of swaps) of 6.84 million MWh in the 2012-13 delivery year. A $1.30/MWh reduction in average LMPs would save Ameren customers $8.89 million, or about 0.07 cents/kWh. On the other hand, ComEd is projected to have a net long position of 4.93 million MWh, in which case a $1.30/MWh LMP reduction would cost ComEd customers $6.41 million, or about 0.03 cents/kWh.

Load-weighted average overall rates are $0.103/kWh for Ameren[47] customers and $0.126/kWh for ComEd[48] customers. Therefore the Ameren impact of 0.07 cents/kWh ($0.0007/kWh) is

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Load Payment is the payment made by the loads in the system. The payment includes that of consumption plus line losses. The hourly payment of a load is MWh consumption times the LMP at the load bus location.

System Cost Index: It is defined as {0.7 * Production Cost + 0.3 * (Load Payment – Generation Credit)}. The System Cost Index quantifies the impact of production cost and congestion on the system operation cost.

Imported Energy is the sum of hourly power flows injected to Illinois. Exported Energy is the sum of hourly power flows extracted from Illinois.

The Cost of Imported/Export Energy is the injected/extracted MWh times the LMP at the bus location where energy is injected/extracted.

[45] This approach differs from that conducted for the 2011 calendar year in that the impact examined is on Ameren and ComEd eligible retail customers only in 2012-13.

[46] This includes electricity procured as part of the 2010 LTPPA, 2010 Procurement Plan, 2011 Procurement Plan and 2012 Procurement Plan.

[47] This includes fixed price residential, small general and general service.

approximately a 0.7% average customer cost savings and the ComEd impact of 0.03 cents/kWh ($0.0003/kWh) is approximately a 0.2% average customer cost increase.

	Load forecast (MWh)	Swap energy volumes (MWh)[49]	Net Short (MWh)	Benefit of LMP reduction attributed to renewables ($)	Estimated rate impact (c/kWh)
ComEd	21,352,151	26,280,000	(4,927,849)	(6,406,204)	0.03
Ameren	11,971,816	5,136,000	6,835,816	8,886,561	(0.07)
Total	33,323,967	31,416,000	1,907,967	2,480,357	(0.01)

Figure 13: Estimated cost impacts of LMP reductions on ComEd and Ameren eligible customers

Economic Development

Illinois State University's Center for Renewable Energy modeled the economic impact of wind energy upon Illinois' economy by entering project specific information into the National Renewable Energy Laboratory's (NREL) Jobs and Economic Development Impact (JEDI) model to estimate the income, economic activity, and number of job opportunities accruing to the state from the project.[50] The report found 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, will generate a total economic benefit of $5.98 billion[51] during the construction phase and 25-year operational life of the projects.

The report found that wind power leads to the creation of temporary and permanent jobs requiring highly-skilled workers in the fields of construction, management, and engineering.[52] Construction phase jobs typically last anywhere from 6 months to over a year, while operational phase jobs, including operations and maintenance positions, last the life of the wind farm, typically 20-30 years.[53]

The report also found that the initial spending on the construction and operation of a wind farm creates a second layer of impacts, which they referred to as "turbine and supply chain impacts" or "indirect impacts."[54] Indirect impacts occurred both in the construction and the operation of wind

[48] This includes residential classes and non-residential watt-hour and small load (<101 kW) classes through Jan. 2012..

[49] These volumes were procured prior to the onset of customer migration and 3,000 MW were procured by ComEd in every hour from June 2012 – May 2013 and 1,000 MW were procured by Ameren for every hour from June – December 2012.

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

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

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

[53] *Id.*

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

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."[55] Finally, the report 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.[56]

The analysis also concluded that local wind turbines raise the property tax base of a county, which can create "a new revenue source for education, fire departments, and other local government services,"[57] since local governments can receive significant amounts of revenue from permitting fees.[58] 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."[59] 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.

Impact of Economic Incentives for Wind Energy

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

- An Investment Tax Credit entitles Illinois developers to a 0.5% income tax credit for investments in qualified property, which may include building, structures, and other tangible property.[60]
- A Jobs Tax Credit entitles Illinois employers to a $500 tax credit for hiring individuals certified as economically disadvantaged.
- A Sales-and-Use Tax Exemption for Building Materials grants Illinois businesses full exemption from sales-and-use tax without having to apply for enterprise zone status.[61]

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[55] *Id*. at 22.

[56] *Id*. at 23.

[57] *Id*. at 11.

[58] *Id*. at 18.

[59] *Id*. at 18.

[60] *Id*. at 15.

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

- Property Tax Valuation of Wind Turbines: The wind energy property assessment division of the Illinois Property Tax Code specifies wind energy devices larger than 500 kilowatts (kW) that produce power for commercial sale be valued at $360,000 per megawatt (MW) of capacity and annually adjusted for inflation according to the United States Consumer Price Index.[62] The depreciation allowance may not exceed 70%. An extension of the law was recently signed and extends the current valuation methodology until the end of 2016, providing greater certainty for all stakeholders in wind energy developments.[63]

At the federal level, the American Taxpayer Relief Act of 2012 modified and extended tax credits and other incentives for wind energy. The production tax credit (PTC) for wind energy, created under the Energy Policy Act of 1992, provides an income tax credit of 2.2 cents per kilowatt-hour for the production of electricity from utility-scale turbines for the first 10 years of electricity production. The PTC, which was previously renewed by the American Recovery and Reinvestment Act of 2009 (ARRA), was extended through the end of 2013 and modified by removing placed in service deadlines and replacing them with deadlines that use the beginning of construction as the basis for determining facility eligibility. Considering the new "under construction" criteria and the fact that the typical construction period for a utility-scale wind project lasts approximately one year, the recent one year extension is essentially akin to a two-year extension under the guidelines set forth in ARRA and previous legislation.

Since its inception, the PTC has been allowed to lapse 3 times; in 2000, 2002 and 2004. Although in each case the credit was extended retroactively, the uncertainty in the market resulted in decreases in new capacity additions ranging from 73% to 93%[64] of the previous year's installed capacity.

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

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

Through Section 1603 ARRA, solar project developers were given the option to receive an equivalent cash payment from the Department of Treasury for the value of the 30% ITC if construction began before the end of 2011 and the project is placed in service by the end of 2016. Also through

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[62] 35 ILCS 200/10-605.

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

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

Section 1603, 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 American Taxpayer Relief Act of 2012 extended this option through the end of 2013 and modified it such that wind projects only need to have started construction to qualify.

2. Environmental Benefits

The environmental benefits of renewable energy resources are mainly associated with the benefits of avoiding the use of traditional generation sources which emit regulated pollutants. For example, the United States Environmental Protection Agency (EPA) has found that emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), hydro fluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) may reasonably be anticipated to endanger public health and welfare.[65] Traditional generation from power plants include air emissions responsible for approximately one-third of nitrogen oxide emissions, two-thirds of sulfur dioxide emissions, and one-third of carbon dioxide emissions nationally, emissions associated with lung diseases such as asthma and chronic obstructive pulmonary disorder.[66] 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.[67]

Environmental benefits can be measured in terms of annual emission benefits, that is, the benefits of not using traditional generation sources such as coal or natural gas which emit restricted pollutants. The same model used to estimate impacts on LMPs was also used to estimate the generation by fuel type and the associated emissions, with and without renewable resources. The emission value and emission costs are represented in Figure 14 below both with and without renewable energy integration. As shown, the renewable energy would reduce CO2 emissions by 5,481,327 tons and nitrous oxide (NOx) by 4,765 tons. The total emission cost reduction is about $75 million with renewable energy integration (given trading values for allowances/credits are NOx: $10,000/ton, CO2: $5/ton). The Agency did not revise this analysis using a wholesale electricity market model for the 2012 calendar year, taking the position that last year's analysis remains generally valid.

Year	Renewable Energy?	CO2 (Ton)	NOx (Ton)	CO2 Cost ($M)	NOx Cost ($M)	Total Emission Cost ($B)
2011	No Renewable Energy	90,386,907	78,114	452	781	1.23
	With Renewable Energy	84,905,580	73,349	425	733	1.16

Figure 14: Emissions Cost Savings from Renewable Resource Integration

[65] 74 Fed. Reg. 66,495 (Dec. 15, 2009).

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

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

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."[68]

The IPA asked Ameren and ComEd to provide their rate spreadsheets by customer class for each of the three delivery years examined, breaking out the additional amounts reflected in the supply charge attributable to renewable resource delivery by delivery year. These rate spreadsheets provide the rate impact associated with the Agency's procurement of renewable resources; Figure 15 and Figure 17 show the rate impact for ComEd and Ameren respectively. When multiplied by the overall billing determinants, the values from the spreadsheets provide the total dollar impact on the annual electricity bills of each customer class; Figure 16 and Figure 18 show the total impact for ComEd and Ameren respectively. When. Results are presented for each electric utility and corresponding customer classes below.

[68] 20 ILCS 3855/1-75(c)(5).

1. ComEd

Customer Class	Description	2009 Plan Year	2010 Plan Year	2011 Plan Year	2012 Plan Year (Through January 2013)
Single Family No Electric Space Heat	Revenue/kWh	$0.118	$0.132	$0.132	$0.128
	REC/kWh	$0.000768	$0.000258	$0.000064	$0.001152
	Ratio (REC/Revenue)[69]	0.65%	0.20%	0.05%	0.90%
Multi Family No Electric Space Heat	Revenue/kWh	$0.134	$0.148	$0.145	$0.141
	REC/kWh	$0.000768	$0.000258	$0.000063	$0.001151
	Ratio (REC/Revenue)	0.57%	0.17%	0.04%	0.81%
Single Family With Electric Space Heat	Revenue/kWh	$0.081	$0.090	$0.085	$0.093
	REC/kWh	$0.000498	$0.000170	$0.000042	$0.000554
	Ratio (REC/Revenue)	0.61%	0.19%	0.05%	0.59%
Multi Family With Electric Space Heat	Revenue/kWh	$0.089	$0.099	$0.093	$0.101
	REC/kWh	$0.000499	$0.000170	$0.000043	$0.000552
	Ratio (REC/Revenue)	0.56%	0.17%	0.05%	0.55%
Watthour	Revenue/kWh	$0.132	$0.145	$0.150	$0.151
	REC/kWh	$0.000780	$0.000270	$0.000060	$0.001240
	Ratio (REC/Revenue)	0.59%	0.19%	0.04%	0.82%
Small Load (< 100 kW)	Revenue/kWh	$0.101	$0.114	$0.113	$0.112
	REC/kWh	$0.000770	$0.000270	$0.000060	$0.001210
	Ratio (REC/Revenue)	0.76%	0.24%	0.05%	1.08%

Figure 15: ComEd Rate Impact – Calculated Bill Impacts of RECs[70]

[69] This value represents the amount that RECs cost each customer of that delivery year class as a percentage of the amount paid for total "annual electricity bills," including taxes. Thus, a Rate Impact of 0.69% means that 0.69% of the total electricity bill of a customer of that class in that delivery year was spent on contracts for renewable energy resources and credits. The rate impacts for June 2010 – May 2011 and June 2011 – May 2012 reported here will differ slightly from those included in the 2012 Report. In the 2013 Report, they include municipal and state taxes, whereas last year they did not include taxes.

[70] Overall bill (e.g. Revenue/kWh) includes fixed supply charges, PJM services charges, delivery services charges (customer charge, standard metering service charges, and distribution facilities charges), other environmental cost recovery and energy efficiency & demand adjustments, franchise cost additions, and municipal and state taxes are excluded. Municipal and state taxes were not included in the in the overall bill figures included in the 2012 Report. Consequently the figures reported for 2010, 2011, and 2012 in this table will be higher than the figures reported for the same years in the 2012 Report.

Customer Class	Description	2009 Plan Year	2010 Plan Year	2011 Plan Year	2012 Plan Year (Through January)
Single Family No Electric Space Heat	Usage (kWh)	24,195,356,771	25,557,124,031	19,578,612,497	10,701,887,906
	Dollar Impact ($)	$18,582,034	$6,593,738	$1,253,031	$12,328,575
Multi Family No Electric Space Heat	Usage (kWh)	4,837,665,365	5,384,174,419	4,182,885,133	2,578,353,684
	Dollar Impact ($)	$3,715,327	$1,389,117	$263,522	$2,967,685
Single Family With Electric Space Heat	Usage (kWh)	881,222,892	506,129,412	649,609,827	350,603,846
	Dollar Impact ($)	$438,849	$86,042	$27,284	$194,235
Multi Family With Electric Space Heat	Usage (kWh)	1,860,212,425	984,758,824	1,364,078,394	693,978,894
	Dollar Impact ($)	$928,246	$167,409	$58,655	$383,076
Watthour	Usage (kWh)	588,208,974	578,444,444	392,413,102	162,401,732
	Dollar Impact ($)	$458,803	$156,180	$23,545	$201,378
Small Load (< 100 kW)	Usage (kWh)	9,766,981,818	8,912,892,593	6,287,525,499	3,555,283,549
	Dollar Impact ($)	$7,520,576	$2,406,481	$377,252	$4,301,893

Figure 16: ComEd Total Dollar Impact[71]

[71] For Plan 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 (RES). Dollar Impact values for those Plan Years were calculated by multiplying the Usage by the REC/kWh reported in Figure 15. For Plan Years 2009 and 2010, the "switching statistics" did not provide this amount of customer class detail; Dollar Impacts values for those years in Figure 16 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 Figure 15.

2. Ameren

Customer Class	Description	2009 Plan Year	2010 Plan Year	2011 Plan Year	2012 Plan Year (Through January)[72]
Residential Service	Revenue/kWh	$0.104	$0.107	$0.108	$0.104
	REC/kWh	$0.000645	$0.000211	$0.000058	$0.000634
	Ratio (REC/Revenue)[73]	0.62%	0.20%	0.05%	0.61%
Small General Service	Revenue/kWh	$0.111	$0.108	$0.107	$0.104
	REC/kWh	$0.000645	$0.000211	$0.000058	$0.000634
	Ratio (REC/Revenue)	0.58%	0.20%	0.05%	0.61%
General Service	Revenue/kWh	$0.086	$0.084	$0.083	$0.074
	REC/kWh	$0.000645	$0.000211	$0.000058	$0.000634
	Ratio (REC/Revenue)	0.75%	0.25%	0.07%	0.85%

Figure 17: Ameren Rate Impacts[74]

Customer Class	Description	2009 Plan Year	2010 Plan Year	2011 Plan Year	2012 Plan Year (Through January)
Residential Service	Usage (kWh)	11,113,952,386	12,099,965,649	11,038,029,446	6,208,746,600
	Dollar Impact ($)	$7,168,499	$2,553,093	$644,621	$3,935,104
Small General Service	Usage (kWh)	3,615,924,697	3,026,300,756	2,544,215,445	1,455,794,675
	Dollar Impact ($)	$2,332,271	$638,549	$148,582	$922,683
General Service	Usage (kWh)	1,240,657,248	623,518,977	443,840,561	218,630,805
	Dollar Impact ($)	$800,224	$131,563	$25,920	$138,568

Figure 18: Ameren Total Dollar Impact

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72 REC/kWh values for 2012 are estimates.

73 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 amount Ameren spent on renewable resources in the delivery year divided by the forecasted load of eligible customers during the same period. *See* 220 ILCS 5/16 115D(d)(1). Thus, a Rate Impact of 0.70% means that 0.7% of the forecasted revenue from that class in the given delivery year was spent on contracts for renewable energy resources and credits.

74 A single company-wide rate is reported for Ameren in the 2013 Report, as opposed to separate rates reported across 3 rate zones as was done in the 2012 Report. This reflects the fact that the merged companies that comprise Ameren are now fully integrated.

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."[75]

An ARES may satisfy its RPS requirement entirely through ACPs or through a combination of an ACP payment and procurement of renewable resources. An ARES must meet at least 50% of its RPS requirement using the ACP mechanism.[76] The law allows ARES to meet 100% of the RPS with the ACP mechanism, though it appears that most ARES choose to use the ACP only for 50% of the required RPS. This behavior is to be expected as long as market prices for REC products which satisfy the RPS requirement for an ARES produce a lower cost alternative to using ACP for 100% of the RPS compliance[77]. This Report has estimated the ACP payment based on the actual published ACP rate and the estimated load of ARES customers. Figure 19 shows ComEd and Ameren ACP rates, historical and estimated.

Delivery Year	ComEd Usage Forecast[78] (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[79]	19,695,906,000	0.09085 (estimated)	11,125,884,000	0.06338 (estimated)

Source: Illinois Commerce Commission, http://www.icc.illinois.gov/downloads/public/ACP%20Rate%20History%20as%20of%202013-01-02.pdf

Figure 19: ACP Rates

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

[76] 220 ILCS 5/16-115D(d).

[77] ARES are required to procure renewable energy or credits equal to at least 8% of total sales. The estimated ACP Rate for ComEd for the June 2012 through May 2013 delivery period is 0.09085 cents/kWh sold, which is equivalent to the cost of buying RECs equal to 8% of sales for 1.136 cents/kWh. That price target significantly exceeds the market price of RECs, based on both the IPA's own procurement (0.970 cents/kWh per Figure 1) and estimates published by the US Department of Energy (http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5).

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

[79] Because it has not been fully delivered, the ACP rate for delivery year 2012-2013 is included as an estimate.

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 Figure 19 above. That is, for an ARES customer in Ameren territory, the ARES rate impact in delivery year June 2009 to May 2010 would be 0.03225 cents per kilowatt-hour.

Since 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, the bill impact of renewable procurement on ARES and utility customers would be similar in dollar amount, although the percentage impact would be somewhat higher given the lower energy prices currently available from ARES, as shown in Figure 20 below.

Utility Territory	ACP Rate (¢/kWh) (estimated) – From Figure 19	Utility Price to Compare (¢/kWh)[80]	Rate Impact on the Supply and Transmission Portion of Fixed Price Utility Supply Customers	Representative ARES Price (¢/kWh)[81]	Rate impact on ARES Customers Assuming 100% ACP (estimated)
ComEd	0.09085	7.60	1.21%	6.39	1.44%
Ameren	0.06338	6.10	1.05%	5.37	1.19%

Figure 20: RPS Compliance – Comparative Rate Impact on ARES Customers

Because the 2010 LTPPAs, the sole "long-term contracts" procured by the IPA, began delivery on June 1st of 2012, there are not yet final "rate impacts" or "total dollar impacts" on ARES customer bills that the Agency can analyze. The ICC's most recent ACP Rate estimate for the June 2012 through May 2013 is shown in Figure 20 above. This estimate includes the effect of the 2010 LTPPAs and reduced energy forecast (resulting primarily from migration form utility supply service). Figure 1 and Figure 2 show the average REC price imputed in ComEd and Ameren 2010 LTPPAs. It is interesting to observe the significantly higher REC prices imputed in these contracts relative to other recent REC purchases. For example, in ComEd the imputed REC price in the LTPPAs is 1.773 cents per kWh while the price of short-term RECS procured pursuant the 2012 Procurement Plan is 0.088 cents per kWh. The long-term nature of the LTPPA (20 years) most likely explains the significant price difference. That is because the

[80] Includes electricity supply and transmission charges. http://www.citizensutilityboard.org/pdfs/NewsReleases/20130218_ElectricReportCard_Report.pdf

[81] Report Card: Illinois' Electricity Market Presented by The Citizens Utility Board (CUB), February 2013. http://www.citizensutilityboard.org/pdfs/NewsReleases/20130218_ElectricReportCard_Report.pdf

price floor in a long-term contract includes the cost of developing, constructing and operating the asset. In contrast, contracts for short-term products are typically priced on the margin, meaning that the marginal cost is the price floor. In competitive markets for long-term and short-term products, the clearing price approximates the price floor.

E. Reporting Requirements in Other States on the Impact of RPS on Customer Rates

To provide some context as to how the reporting requirements on the costs and benefits of renewable resource procurement in Illinois compare to those in other states, a review of filings required by legislative and regulatory bodies in selected states was conducted. This review considered the requirements in California, Colorado, Wisconsin, Minnesota and New York.

In each of the selected states, with the exception of New York, utilities are required to report on the impact of renewable procurements on customer rates. In New York a State agency, the New York State Energy Research and Development Authority (NYSERDA), is responsible for administering RPS procurements for all but a handful of the state's RPS requirements. NYSERDA prepares an annual report containing information about progress against the state's RPS and the associated expenses to procure renewable energy. The main difference between the reporting requirements in New York and those in California, Wisconsin, and Minnesota is that the cost of procuring renewable energy is not referenced to the retail customer's rate.

The requirements in the remainder of the states include:

- **California:** The California Public Utilities Commission (PUC) issues quarterly reports pursuant to state legislation on the RPS program focusing on the three large investor owned utilities: Pacific Gas & Electric, Southern California Edison and San Diego Gas and Electric. The reports summarize progress to date of the three utilities against the RPS requirements, including an overview of aggregated volumes and costs. The 4th quarter report shows the weighted average cost impact of renewable procurements for each utility.
- **Colorado:** Colorado PUC Rule 3662 compels investor-owned qualifying retail utilities to file an annual compliance report to demonstrate compliance with the state's renewable energy standard (RES). Reports filed by Public Service Company of Colorado detail the renewable resources they own or from which they contract energy to meet the RES. These reports also provide a breakdown of the costs associated with these procurements, although they aren't referenced to customer rates.
- **Minnesota:** The reporting requirements in Minnesota are contained in a statute that requires the filing of a report by utilities showing the impact of renewable energy on retail customer's rates. The Minnesota PUC issued a notice in 2011 providing guidance around the reporting requirements that stated reports should include clear narrative explanations of the modeling methods and the assumptions used in developing the cost and rate impacts for both past and future periods, including but not limited to: comparative energy and capacity sources and costs, environmental costs and benefits, and transmission costs and benefits. The reports should also include a discussion of any limitations, sensitivities, and uncertainties in the analyses and how those factors could impact the results.
- **Wisconsin:** The Wisconsin legislature has approved a statute that requires the Wisconsin Public Service Commission (PSC) to submit a report biannually which evaluates the impact of the state RPS on the rates and revenue requirements of electric providers and compare the impact that would have occurred if renewable energy practices of providers were subject to market forces in the absence of RPS requirements.

While the reporting requirements in each state consider the cost of renewable procurement, none touch on the benefits. That characteristic distinguishes Illinois – which does require a consideration of benefits – from the other states considered. It should also be noted that as a state with retail competition, the price of electricity in Illinois is not easily calculated. In Illinois comparisons can only be accurately made using the price paid by customers on default service.

IV. 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."***[82]

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.[83] At least 60% of the renewable energy resources procured by an ARES must be from wind generation and, starting June 1, 2015, at least 6% of the renewable energy resources procured must be from solar photovoltaics.[84] If an ARES does not purchase at least these levels of specified renewable energy resources, then it is required to make additional ACPs. An ARES must meet at least 50% of its renewable resource requirements by making ACPs, and may meet the entirety of its renewable resource obligation through ACPs.[85] All ACPs are placed into the Agency's Renewable Energy Resources Fund ("RERF")[86] which could then to be used to purchase RECs.[87] The price paid to procure RECs using monies from the RERF cannot exceed the winning bid prices paid for like resources procured for electric utilities.[88] As of this report date, most ARES have chosen to meet only the minimum amount of the RPS requirement (50%) using the ACP mechanism.

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[82] 220 ILCS 5/16-115D(d)(4).

[83] 220 ILCS 5/16-115D(a).

[84] 220 ILCS 5/16-115D(a)(3) (the 60% statutory wind energy minimum for ARES is lower than the 75% wind standard for utilities).

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

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

[87] 20 ILCS 3855/1-56.

[88] 20 ILCS 3855/1-56(d).

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.[89] Under the PUA, a "planning year" begins on June 1st of each calendar year.[90] 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.[91] Therefore, this report must provide the aggregate total amount of ACPs for planning years June 2009 – May 2010, June 2010 – May 2011, and June 2011 – May 2012. Figure 21 shows the amount of ACPs received by the IPA through Q4 2012.

Planning Year	Funds Received	Total ACPs
June 2009 – May 2010	2010 – Quarters 3 and 4	$7,148,261.61
June 2010 – May 2011	2011 – Quarter 3 and 4	$5,606,245.18
June 2011 – May 2012	2012 – Quarter 3 and 4	$2,156,777.61
Aggregate Total		**$ 14,911,284.40**

Figure 21: Total ACPs Received

B. Amount of ACPs used to purchase RECs

To date, no RECs have been purchased using any RERF funds. Of the $7,148,261.61 in total ACPs received for the June 2009 – May 2010 planning year, the State of Illinois borrowed $2,000,000 on September 20, 2010 and $4,710,000 on October 15, 2010.[92] The remaining $438,261.61 was not used to purchase RECs and remained in the RERF. The State was required to repay the borrowed 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 borrowed from a non-interest earning account, no interest was paid.

While the IPA believes that its use of the RERF is not subject to inclusion in its Procurement Plans because the Commerce Commission does not have jurisdiction over how the IPA spends the RERF, there was no stated plan regarding use of the RERF's initial deposits.

In the third and fourth quarters of 2011, the IPA received a total of $5,606,245.18 in ACPs for the June 2010 – May 2011 planning year and in the third and fourth quarters of 2012 the IPA received a total

[89] 220 ILCS 5/16-115D(d)(4)(A).

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

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

[92] 30 ILCS 105/5h(a).

of $2,156,777.61 which, to the extent the funds remain available, will be used in accordance with the IPA Act.[93] Additionally, the IPA plans to use ACP funds to purchase RECs curtailed from the LTPPAs in accordance to the IPA's proposal outlined in the approved 2013 Procurement Plan.

C. Balance in RERF attributable to ACPs

As of this report date, the RERF balance equals $14,911,284.40, the total amount received in the Agency's RERF attributable to ACPs. Figure 22, below, shows the current IPA RERF balance sheet. In September 2013, the IPA expects to receive about $40 million in ACPs for the June 2012 – May 2013 planning year. These expected payments, in the aggregate, are significantly higher than prior year payments. The higher amount is a direct result of significant load switching from utility supply to RES supply in recent months, primarily driven by municipal aggregation activities.

Illinois Power Agency Renewable Energy Resources Fund			
Date	Transaction	Amount	Cumulative balance
9/2010	ACPs received	$7,148,261.61	$7,148,261.61
9/2010	Loan to State	-($2,000,000.00)	$5,148,261.61
10/2010	Loan to State	-($4,710,000.00)	$438,261.61
9/2011	ACPs received	$5,606,245.18	$6,044,506.79
3/2012	Repayment by State	$2,000,000.00	$8,044,506.79
4/2012	Repayment by State	$4,710,000.00	$12,754,506.79
9/2012	ACPs received	$2,156,777.61	$14,911,284.40

Figure 22: IPA RERF Balance Sheet

D. Future Use of the ACP-Funded RERF

The ACP mechanism is a useful construct to comply with RPS requirements in a competitively neutral way. That is, it allows an opportunity for additional customer costs of renewable resources to be the same, on an average cents per kilowatt-hour basis, whether the customer takes electricity supply from a utility or an ARES. Although there was no statutory requirement to do so, in its 2013 Procurement Plan the IPA included as a courtesy to interested parties a description of the IPA's decision to use the RERF to procure renewable resources, specifically RECs that were curtailed under the 2010 LTPPAs. The IPA noted that conducting parallel utility and ARES Distributed Generation procurements would be ideal, as this is a currently unfulfilled mandate. The IPA highlighted that the minimum required term for Distributed Generation contracts is 5 years. However, as the IPA noted in its filings, it did not have the

[93] 20 ILCS 3855/1-56.

statutory authority at this time to spend the RERF on procurements that were not parallel with utility procurements.

Against the background of the IPA's actual and aspirational uses of the RERF, one current legislative proposal does away with the ACP mechanism, and instead would require the IPA to facilitate RPS compliance for all retail electric customers regardless of supplier, funded through a delivery charge applicable to every customer. ARES would be free to offer their customers a retail product that consists of more renewable energy resources than required by the RPS. While this proposal removes volumetric risk from the IPA, it raises issues of monopsony and inefficient markets which should be further examined before adoption. There may be mechanisms to address these concerns, but the IPA has not had the opportunity to fully and properly analyze the full impact on the market of possible solutions.

V. Appendix 1: Studies for the Costs of Intermittency Analysis

A. List of Studies Reviewed

A list of the studies reviewed is included in Table 1. Brief descriptions of these studies are included in the next section.

Study Name	Author	Publication Date
Eastern Wind Integration and Transmission Study (EWITS)	NREL-EnerNex	Feb-11
Western Wind and Solar Integration Study (WWSIS)	NREL-GE Energy	May-10
Analysis of Cycling Costs in Western Wind and Solar Integration Study	NREL	Jun-12
The Impact of High Wind Power Penetrations on Hydroelectric Unit Operations in the WWSIS	NREL	Jul-11
Impact of Wind and Solar on Fossil-Fueled Generators	NREL	Aug-12
Power Plant Cycling Costs	NREL - Intertek APTECH	Jul-12
The Value of Wind Power Forecasting	NREL	Apr-11
Impacts of Wind Generation Integration	EPRI	Apr-11
PacifiCorp 2012 Wind Integration Resource Study	PacifiCorp	Nov-12
Integration of Renewable Resources	CAISO	Aug-10
European Wind Integration Study (EWIS): Towards a Successful Integration of Wind Power into European Electricity Grids	EWIS	Apr-10
Costs of Integration for Wind and Solar Energy: Large-scale Studies and Implications	NREL	Jan-11
Public Service Company of Colorado 2 GW and 3 GW Wind Integration Study	Xcel Energy – EnerNex	Aug-11
Pacific Gas &Electric filing in the ISO - 2010 Long Term Procurement Plan docket	PG&E	July-11
Summary of Preliminary Results of 33% Renewable Integration Study – 2010 CPUC LTPP Docket No. R.10-05-006	CAISO	May-11
2011 Wind Technologies Market Report	U.S. Department of Energy	Aug-12

Table 1: List of Studies Reviewed

B. Summary of Studies Reviewed

The following are brief summaries of each of the studies reviewed.

Eastern Wind Integration and Transmission Study (EWITS)	NREL & EnerNex	Feb-11
The EWITS was prepared for NREL by EnerNex Corporation and was revised in February 2011. It examines the operational impact of multiple wind penetration scenarios on the Eastern Interconnect (EI) system. Four penetration scenarios were considered: • Three simulated a 20% wind energy penetration (percentage of annual electric energy requirements) by 2024 based on different siting (close to high-quality wind vs. close to load centers) and technologies (onshore vs. offshore) • One simulated a 30% wind energy penetration. The study evaluated the system's ability to provide enhanced operational flexibility and identified the need for and provided recommendations on mitigation strategies under these four scenarios.		

Western Wind and Solar Integration Study (WWSIS)	NREL & GE Energy	May-10
The WWSIS is a sister study of the EWITS and was prepared for NREL by GE Energy. It investigates the operational impact of multiple wind and solar penetration scenarios on the WestConnect group of utilities in Arizona, Colorado, Nevada, New Mexico and Wyoming. The WWSIS used multiple scenarios to evaluate different amounts wind and solar energy penetration by 2017 (from 11% to 35% - percentage of annual energy electric requirements), different siting for wind and solar resources and a wide array of sensitivities. The study evaluated the system's ability to provide enhanced operational flexibility and identified the need for and provided recommendations on mitigation strategies under the scenarios considered.		

Analysis of Cycling Costs in Western Wind and Solar Integration Study	NREL	Jun-12
This analysis was prepared by NREL and leverages the results of the WWSIS. It examines in greater detail the additional costs associated with thermal unit cycling requirements considering a 30% (as a percentage of annual energy load) penetration of intermittent renewables. This study provides estimates of the additional system-level cycling costs involved when moving from a no renewable scenario to a 30% penetration level scenario. Furthermore, it quantifies the impact of these additional costs on the value of renewable energy and put them into perspective by comparing them to the magnitude of generators revenue losses due to reduced dispatch and energy market prices.		

The Impact of High Wind Power Penetrations on Hydroelectric Unit Operations in the WWSIS	NREL	Jul-11

This study was also prepared by NREL and leverages the results of the WWSIS. It describes the impact of a large amount of wind penetration (up to 30%, as a percentage of annual energy load) on the operation of hydroelectric power plants. In particular, this study investigates:

- Changes in operating patterns for both individual and groups of hydroelectric power plants
- The impact on costs of maintaining the flexibility of hydro generators, given multiple system operation modes

Impact of Wind and Solar on Fossil-Fueled Generators	NREL	Aug-12

NREL's "Impact of Wind and Solar on Fossil-Fueled Generators" study was presented at the IEEE Power and Energy Society General Meeting in San Diego, California. It examines the wear and tear impacts on thermal power plants due to increased cycling, deeper load following and rapid ramping required to accommodate high penetrations of wind and solar energy. This study discusses in details the following impacts of additional wear and tear:

- Increase in Capital and Operations & Maintenance (O&M) costs
- Increase in equivalent forced outage rates
- Degraded performance and efficiency (heat rate degradation and the associated increase in emissions)

Power Plant Cycling Costs	NREL & Intertek APTECH	Jul-12

This report has been prepared by Intertek APTECH for NREL and the Western Electricity Coordinating Council (WECC). It provides data on power plant cycling costs, an overview of systems and components commonly affected by cycling as well as mitigation actions to minimize these costs.

The Value of Wind Power Forecasting	NREL	Apr-11

NREL's conference paper "The Value of Wind Power Forecasting" was presented at the 91st American Meteorological Society Annual Meeting, the Second Conference on Weather, Climate and the New Energy Economy in Washington, DC. It leverages the models developed for the WWSIS study in order to evaluate the operating cost impacts of enhanced day-ahead wind forecasts.

Impacts of Wind Generation Integration	EPRI	Apr-11

This report summarizes results from a number of other studies of wind integration in Europe and North America and which were not separately reviewed for the IPA's report, in particular a study from the International Energy Agency.

PacifiCorp 2012 Wind Integration Resource Study	PacifiCorp	Nov-12
This study has been prepared by PacifiCorp and supports PacifiCorp's 2013 Integrated Resource Plan (IRP). Given PacifiCorp's existing wind capacity and short-term build plan, it estimates the operating reserves required to maintain PacifiCorp's system reliability and comply with the North American electric Corporation (NERC) regional reliability standards.		

Integration of Renewable Resources	CAISO	Aug-10
This study was prepared by the California Independent system Operator (CAISO). The objective of this report is to describe the impacts on system operations and wholesale markets of achieving a 20% Renewable Portfolio Standard (RPS) target (as a percentage of annual energy load) in California and assess the capability of the existing conventional generation to maintain reliability under these conditions.		

European Wind Integration Study (EWIS) Towards a Successful Integration of Wind Power into European Electricity Grids	EWIS	Apr-10
This presentation from the European Wind Integration Study (EWIS) quantifies the costs and benefits of wind integration into European electricity grids. It focuses on the financial benefits of reduced emissions and fossil fuel usage, wind integration costs, grid reinforcements costs and assesses storage as a mitigation solution to facilitate the wind integration.		

Costs of Integration for Wind and Solar energy: Large-scale studies and implications	NREL	Jan-11
This presentation has been prepared by NREL for a Massachusetts Institute of Technology (MIT) wind integration workshop. It summarizes the main findings of the EWITS and the WWSIS studies and focuses on what is needed for large-scale wind and solar integration as well as the associated integration costs.		

Public Service Company of Colorado 2 GW and 3 GW Wind Integration Study	Xcel Energy - EnerNex	Aug-11
This study has been prepared by Xcel Energy and EnerNex Corporation and represents the third wind integration cost study completed by Public Service Company of Colorado (Xcel Energy). It assesses the impact of two wind penetration levels on Xcel Energy's system - 2GW and 3GW (nameplate capacity) - and investigates the costs associated with these two penetration levels.		

PG&E's filing to the CAISO - 2010 Long Term Procurement Plan	PG&E	Jul-11
Pacific Gas and Electric (PG&E) is required by the CAISO to file a Long Term Procurement Plan (LTPP) which must describe PG&E's approach to meet future demand at the lowest cost possible for its customers. The LTPP should also "study four different RPS scenarios that achieve a 33% RPS by 2020". PG&E's LTTP filing examines the operating needs and associated costs to integrate renewable and other non-dispatchable resources.		

Summary of Preliminary Results of 33% Renewable Integration Study – 2010 CPUC LTPP Docket No. R.10-05-006	CAISO	May-11
This presentation, completed by the CAISO, summarizes the results of a 33% (as a percentage of annual energy load) renewable integration study produced through a collaborative process between the CAISO, PG&E, Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E). This presentation addresses the operational requirements to achieve 33% RPS by 2020 in California, presents production simulation results for four resource plan scenarios and provides an analysis of the fleet flexibility in 2020.		

2011 Wind Technologies Market Report	U.S. Department of Energy	Aug-12
This report, compiled by the U.S. Department of Energy (DOE), provides a comprehensive set of statistics with regard to the U.S. and worldwide wind energy markets, such as wind capacity growth, domestic wind turbine and component manufacturing capacity growth, turbines costs, etc. Most importantly, it includes a summary of wind integration costs gathered from the existing literature and a summary of potential operational and policy actions which can be implemented to mitigate intermittency costs.		