2012

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

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

Illinois Power Agency

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IPA

ILLINOIS POWER AGENCY Pat Quinn, Governor

Arlene A. Juracek, Acting Director

March 30, 2012

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,

Arlene A. Juracek

Arlene A. Juracek
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 30, 2012

I. Executive Summary and Key Findings

Public Act 97-0658, effective January 13, 2012, establishes new 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 purchased 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, dated March 30, 2012, 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

<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

Deliveries under some of these procurement events are for future delivery periods (i.e. beginning June 1, 2012 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 low of 0.095 cents per kilowatt-hour to a high of 1.927 cents per kilowatt-hour. The current price trend is downward and the purchases represent a low of 0.05% to a high of 0.81% of the total rates paid for electricity. In the Ameren territory, the cost of purchasing renewable energy resources ranged from a low of 0.092 cents per kilowatt-hour to a high of 1.586 cents per kilowatt-hour. The current price trend is downward and the purchases represent a low of 0.05% to a high of 0.83% of the total rates paid for electricity.
- 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. Care must be taken, however, to not optimistically extrapolate these results without limit, as factors such as market prices for energy, transmission constraints, and uncertainty in the load serving responsibility will affect the cost-effectiveness of near term future additions to the renewable resource generation stock in Illinois. In particular, care must be taken to avoid the creation of new stranded costs through long-term contracts until such time as the effects of retail utility load shifts due to factors such as municipal aggregation can be assessed.
- Renewable resources, in particular wind, have played a dramatic role in reducing 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 has lowered Illinois' average LMPs by $1.30 per mega-watt hour (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.
- The 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 intends to include an analysis and proposal for the use of the ACP-funded IPA Renewable Energy Resources Fund (RERF) in its 2013 Procurement Plan, to be filed in the fall of 2012. Under the Energy Infrastructure Modernization Act (EIMA), the IPA must include specific amounts of

distributed generation in RERF purchases.[1] 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 mechanism is a risky proposition.

- An alternative use of the ARES-funded RERF, to be examined in the 2013 Procurement Plan, may be to offset the migration risks of municipal aggregation to utility REC contract obligations. That is, as load shifts to ARES from utilities, it is appropriate for ARES-provided funding to assist with covering contractual purchase obligations for both existing and future utility REC contracts.
- New legislation currently before the General Assembly, SB 678, as amended, proposes to do away with the ACP mechanism, instead requiring the IPA to facilitate base RPS compliance for all retail electric customers regardless of supplier. While this proposal removes volume risk, it raises issues of monopsony and inefficient markets which should be further examined before adoption. Furthermore, until legislative certainty is achieved around this proposal, it is not advisable to use existing RERF funds to underwrite any long-term contractual commitments for renewable resources.

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

II. Introduction and Background

A. History of the Illinois Power Agency

The IPA was established in 2007 by Public Act 95-0481 (IPA Act), to improve the process of procuring electricity for Illinois residential and small commercial customers of the state's largest electric utilities, the Ameren Illinois Company (Ameren) and Commonwealth Edison Company (ComEd).[2] The IPA's goals and objectives are to accomplish each of the following:

- Develop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability, for residential and small commercial customers of Ameren and ComEd. The procurement plan is updated on an annual basis and includes renewable energy resources sufficient to achieve the renewable portfolio standards.
- Conduct competitive procurement processes to procure the supply resources identified in the procurement plan.
- Develop, electric generation and co-generation facilities that use indigenous coal or renewable resources, or both, financed with bonds issued by the Illinois Finance Authority.
- Supply electricity from any Agency facilities at cost to one or more of the following: municipal electric systems, governmental aggregators, or rural electric cooperatives in Illinois.

The IPA has also been authorized to implement other legislative initiatives, such as developing sourcing agreements for clean coal facilities,[3] substitute natural gas plans,[4] and feedstock procurement for these facilities if developed.[5]

The Agency is an independent agency under the jurisdiction of the Executive Ethics Commission, and its operations are self-funded through bidder and supplier fees, as well as earnings from the Illinois Power Agency Trust Fund, established in accordance with the State Finance Act.[6]

Per the IPA Act and the Illinois Public Utilities Act (PUA), beginning June 1, 2008, ComEd and Ameren are required to procure power for residential and small commercial

[2] 20 ILCS 3855/1-5. MidAmerican may choose to also participate in this process, but does not at present.

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

[4] 220 ILCS 5/9-220(h).

[5] 20 ILCS 3855/1-78.

[6] 30 ILCS 105/6z-75.

customers according to a plan developed by the IPA and approved by the Illinois Commerce Commission (Commission or ICC).[7] Notably, the procurement plan only addresses the electricity needs for residential and small commercial customers for ComEd and Ameren, referred to as "Eligible Retail Customers."[8] Each year, by July 15th, ComEd and Ameren will provide load forecasts to the IPA covering the 5-year procurement planning period along with supporting data and assumptions for provided load scenarios. For Eligible Retail Customers, the IPA is required to prepare and receive comments on a draft Procurement Plan by August 15th of each year, and file its proposed Procurement Plan with the Commission for its consideration and approval.[9] The Procurement Plan shall identify the portfolio of demand-response and power and energy products to be procured.

The annual IPA procurement process shall include each of the following components:

- Solicitation, pre-qualification, and registration of bidders;
- Standard contract forms and credit terms and instruments;
- Establishment of a market-based price benchmark;
- Request for proposals competitive procurement process; and
- A plan for implementing contingencies in the event of supplier default or failure of the procurement process to fully meet the expected load requirement due to insufficient supplier participation, Commission rejection of results, or any other cause.[10]

B. History of the Renewable Portfolio Standard

1. Electric Utilities' Compliance with the RPS

Since 2009, the IPA's annual electricity procurement plans have included purchase of renewable energy resources sufficient to meet the RPS applicable to the eligible load of ComEd and Ameren. The RPS calls for the procurement of the following quantity of renewable energy resources as a mandatory part of each utility's annual supply:

- At least 2% by June 1, 2008;
- At least 4% by June 1, 2009;
- At least 5% by June 1, 2010;
- At least 6% by June 1, 2011;

[7] 20 ILCS 3855/1-20(a) and 220 ILCS 5/16-111.5(d).

[8] 220 ILCS 5/16-111.5; see also page 10 of this Report.

[9] 220 ILCS 5/16-111.5(d).

[10] 20 ILCS 3855/1-20(a).

- At least 7% by June 1, 2012;
- At least 8% by June 1, 2013;
- At least 9% by June 1, 2014; and
- At least 10% by June 1, 2015.

This obligation increases by at least 1.5% each year thereafter to at least 25% by June 1, 2025.[11] The obligation of each electric utility is determined by applying the required percentage to the amount of eligible retail sales from the immediately prior planning year.

Eligible "renewable energy resources" include energy and its associated renewable energy credits or stand-alone renewable energy credits from wind, solar thermal energy, photovoltaic cells and panels, biodiesel, anaerobic digestion, crops and untreated and unadulterated organic waste biomass, tree waste, hydropower that does not involve new construction or significant expansion of hydropower dams, and other alternative sources of environmentally preferable energy.[12] The RPS is also subject to specific directives on the type and location of eligible resources:

- *Resource Limitations*: To the extent that it is available, at least 75% of the renewable energy resources used to meet these standards shall come from wind generation and, beginning on June 1, 2011, at least the following percentages of the renewable energy resources used to meet these standards shall come from solar photovoltaics on the following schedule:
    - 0.5% by June 1, 2012,
    - 1.5% by June 1, 2013;
    - 3% by June 1, 2014; and
    - 6% by June 1, 2015 and thereafter.

[11] 20 ILCS 3855/1-75(c).

[12] Landfill gas produced in Illinois is also considered a renewable energy resource, but the law specifically excludes the incineration or burning of tires, garbage, general household, institutional, and commercial waste, industrial lunchroom or office waste, landscape waste other than tree waste, railroad crossties, utility poles, or construction or demolition debris, other than untreated and unadulterated waste wood. 220 ILCS 3855/1-10.

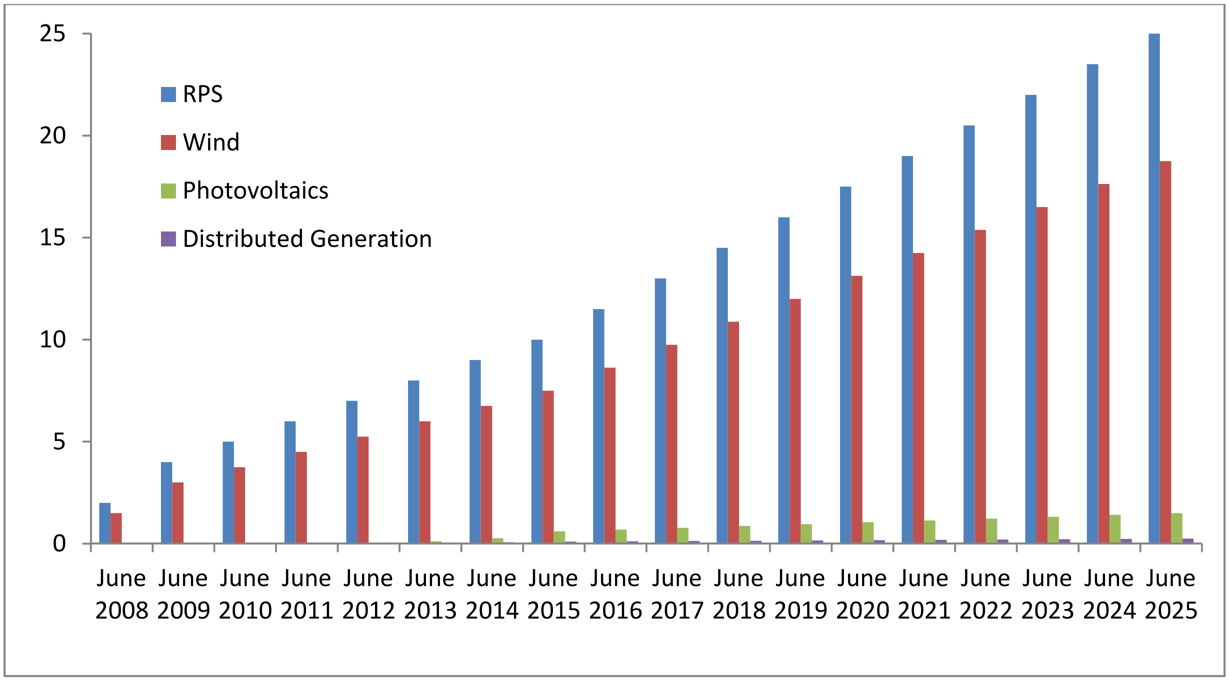

Figure 1: Illinois RPS % Requirements and Generation Preferences

- *Geographic Limitations*: Until June 1, 2011, in-state resources were granted preference unless there were not enough cost-effective resources within Illinois, in which case renewable energy resources from adjoining states (Indiana, Missouri, Kentucky, Wisconsin, Michigan, and Iowa) could be considered.[13] If sufficient cost-effective resources were not available, resources could be purchased from elsewhere. Since June 1, 2011 resources from either Illinois or adjoining state resources receive equal preference before procurement from other states can be considered.

- *Cost- Effectiveness*: All renewable energy resources procured through the IPA must be "cost effective," which means that the costs of procuring those resources do not cause the statutory spending cap to be exceeded and that the costs do not exceed benchmarks based on market prices for renewable energy resources in the region.[14] The statutory spending cap operates as a maximum allowable percentage impact on the amounts paid by eligible retail customers. Starting out at a small level, beginning in 2012, the IPA's procurement of eligible resources under the RPS cannot cause the amounts paid by these customers to increase by more than the greater of 2.015% of the amount paid per kilowatt-hour during the year ended May 31, 2007

[13] 220 ILCS 3855/1-75(c)(3).

[14] 20 ILCS 3855/1-75(c). The Commission reviewed the statutory spending cap in June 2011 and found that the cap "does not unduly constrain the procurement of cost-effective renewable energy resources and that such a limitation remains appropriate." *See* Ill. Commerce Comm'n, Report to the Ill. General Assembly Concerning Spending Limits on Renewable Energy Resource Procurement at ii (June 2011). The Commission's Report also found that the IPA Act's cap on price increases "will *not* unduly constrain future purchases of renewable energy." *Id.*

(including supply, transmission, distribution, surcharges, and taxes), or the incremental amount per kilowatt-hour paid for these resources in 2011. These limits are used, in conjunction with updated load forecasts from the utilities, to calculate a renewable resource budget in total dollars for each renewable resource procurement conducted by the IPA. While the cost-effectiveness spending caps have not limited purchases for the 2009-2011 period, two factors may cause limits on available spending budgets to constrain future purchases. These include dramatic reductions in utility load-serving obligations due to municipal aggregation and the inclusion of solar photovoltaic (PV) RECs, which are significantly more expensive than wind. It is possible that Alternate Compliance Payments made by alternate suppliers may be used to assist in mitigating load migration risk. This will be examined in the 2013 Procurement Plan. The impacts of PV REC purchases on the cost-effectiveness calculations will also be closely monitored.

- *Distributed Generation Requirement*: A Distributed Generation component is mandated for deliveries beginning June 1, 2013, meaning that of the renewable energy resources procured pursuant to the RPS, at least the following percentages shall come from distributed renewable energy generation devices: 0.5% by June 1, 2013, 0.75% by June 1, 2014, and 1% by June 1, 2015 and thereafter.[15] The law defines distributed generation as a device that is powered by a renewable resource, connected at the distribution system level of an electric utility, ARES, municipal utility or rural electric cooperative, located on the customer side of the customer's meter, used primarily to offset that customer's electricity load and limited in nameplate capacity to no more than 2,000 kilowatts. The new standard also requires that, to the extent available, half of the renewable energy resources procured from distributed renewable energy generation shall come from devices of less than 25 kilowatts in nameplate capacity. Renewable energy resources procured from distributed generation devices may also count towards the required percentages for wind and solar PV. Procurement of renewable energy resources from distributed renewable energy generation devices shall be done on an annual basis through multi-year contracts of no less than 5 years, and shall consist solely of RECs. The IPA has begun a workshop process to assist with defining the Distributed Generation procurement to be included in its proposed 2013 Procurement Plan.

Eligible Retail Customers, that is, those customers for whom the IPA directs procurement of energy supply, are defined as retail customers that purchase power and energy from the utility under fixed price bundled service tariffs excluding:

- Customer classes whose service is declared or deemed competitive under Section 113 of the PUA;
- Self-generating customers;

[15] 20 ILCS 3855/1-56.

- Hourly priced customers (however, an amount equal to the ACP, described below, is added to the procurement budget to allow RPS compliance for utility supply to hourly priced customers); and
- Customers otherwise ineligible for bundled service.[16]

For ComEd, eligible retail customer classes include[17]:

SF	*Single Family Non-Space Heating*
MF	*Multi Family Non-Space Heating*
SFSH	*Single Family Space Heating*
MFSH	*Multi Family Space Heating*
WH	*Watt Hour, Non Residential, Less Than 2000 kWh per Billing Period*
Small	*Small Load, Non Residential, Less than 100 kW Peak Demand*
DD	*Dusk to Dawn Lighting Delivery*
GL	*General Lighting Delivery*

For Ameren, eligible retail customer classes include[18]:

DS-1	*Residential*
DS-2	*Non Residential, Less than 150 kW Peak Demand*
DS-3a	*Non Residential, Between 150-400 kW Peak Demand*
DS-5	*Lighting*
QF	*Qualifying Facilities*[19]

2. Alternative Retail Electric Suppliers' Compliance with the RPS

In 1997, Public Act 90-561, the "Electric Service Customer Choice and Rate Relief Act," restructured electricity markets and phased in a competitive retail electric supply market in Illinois.[20] All customers of ComEd and Ameren were given the option to purchase electricity from an ARES or their local utility. In 2007, the PUA was amended to direct ComEd and Ameren to file tariffs establishing utility consolidated billing (UCB) and

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[16] 220 ILCS 5/16-111.5.

[17] Ill. Commerce Comm'n, Docket 10-0563, Final Order at 19 (Dec. 21, 2010).

[18] *Id.*

[19] Ameren must procure energy from any qualifying facility meeting the requirements of Rider QF – Qualifying Facilities. Such qualifying purchases are considered to be preexisting purchase and shall be recovered in Accrued Expenses for the Purchase Electricity Adjustment. Ill. Commerce Comm'n, Docket 10-0563, Final Order at 19 (Dec. 21, 2010).

[20] 220 ILCS 5/16-101(a).

purchase of receivables (POR) service.[21] The General Assembly passed these measures to "promote fair and open competition in the provision of electric power and energy and to prevent anticompetitive practices in the provision of electric power and energy," which they found in the best interest of Illinois energy consumers.[22]

Ameren filed UCB/POR tariffs in September of 2008 and the Commission submitted a final order in August of 2009.[23] ComEd filed its corresponding tariffs in January of 2010, and the Commission submitted a final order in December of 2010.[24] Although the residential and small business electricity market had technically been open to competition for a number of years, it was not until the UCB/POR process was established that residential customers began to contract with ARES in significant numbers. In January of 2011, 1,188 ComEd residential customers received supply service from an ARES; one year later, that number had grown to 270,727. In Ameren territory, 163 residential customers received supply service from an ARES in January of 2011, which increased in one year to 46,078.[25]

The renewable energy obligation for ARES is measured as a percentage of the actual amount of metered electricity (megawatt-hours) supplied by the ARES in the compliance year. ARES must meet at least 50% of their renewable energy resource obligations through the Alternate Compliance Payment (ACP) mechanism.[26] The remaining 50% of the obligation may be met with additional ACP payments, by procuring renewable energy, or by procuring RECs sufficient to comply with the RPS. ARES must utilize the PJM Interconnection's (PJM) Environmental System Generation Attribute Tracking System (PJM-GATS) or the Midwest Renewable Energy Tracking System (M-RETS) used within the territory covered by the Midwest Independent System Transmission Operator (MISO). [27] ACPs are remitted by ARES directly to the ICC, and the ICC forwards that money to the

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[21] 220 ILCS 5/16-118(b) and (c). The POR mechanism mandated that ARES would have an option to have the utility purchase uncollectible receivables for power and energy service for two unpaid billing cycles per residential or small business customer, provided the customer was returned to the electric utility and the ARES made reasonable collection efforts on the account. The UCB mechanism mandated that ARES would have an option to have the utility produce and provide customers with a single bill including both delivery service provided by the utility and energy service provided by the ARES, and to identify the ARES the customer is receiving service from.

[22] 220 ILCS 5/16-118(a).

[23] Ill. Commerce Comm'n, Consolidated Dockets 08-0619, 08-0620, and 08-0621, Final Order at 2 (Aug. 19, 2009).

[24] Ill. Commerce Comm'n, Docket 10-0138, Final Order at 2 (Dec. 15, 2010). Certain aspects of this Final Order are the subject of appeals to the Illinois Appellate Court.

[25] *See, e.g.* "Supply Options Chosen by Customers of Ameren Illinois Company d/b/a Ameren Illinois - Rate Zone I As of January 31, 2012" (ICC Electric Switching Statistics) published by the ICC and available at http://www.icc.illinois.gov/electricity/switchingstatistics.aspx.

[26] 220 ILCS 5/16-115D(a)(2) and (d)(3).

[27] The PJM interconnection coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia, including the ComEd service territory. MISO coordinates the

RERF administered by the IPA for use in purchasing RECs. The IPA is directed to purchase and retire renewable resources at a price not to exceed the winning bid prices for like resources under the IPA's procurements for electric utilities.[28] Thus the IPA central procurement model used for RPS compliance by electric utilities effectively extends to at least 50% (and possibly more) of the load served by ARES. The ACP rate, which is essentially the average price of RECs purchased for the utilities, fluctuates from year to year based on the results of IPA procurement events. Nevertheless, because the ACP is tied to the average prices for renewable resources purchased by the utilities, the mechanism allows for competitive neutrality with respect to RPS compliance costs passed through to all retail electric customers.

C. 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,"[29] this report focuses its analysis on the years 2009 through 2011. 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.[30] 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."[31]

The IPA would like to thank ComEd, Ameren and the Staff of the Illinois Commerce Commission for their assistance in preparing this Report. The IPA also would like to thank Adica, its procurement planning consultant, for its assistance in preparing this Report.

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movement of wholesale electricity in all or parts of 11 Midwestern states, including the Ameren service territory.

[28] *See* 20 ILCS 3855/1-56(d) and (e)

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

[30] 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).

[31] 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."[32]

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; and
- The actual average cost of energy (and for Ameren capacity) procured by the Agency from conventional supply sources in that year's procurement.[33]

Although long-term power purchase agreements (LTPPA), which include bundled long-term renewable energy and the associated RECs, were procured in 2010, their delivery does not being until June 1, 2012.[34] The price of these bundled energy and REC products is noted in the tables but not included in the calculations since delivery has not begun. Similarly, 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 actual energy prices procured for use by the end customer. In general, except for the LTPPAs, the REC costs are additive to the conventional supply costs when calculating individual customer rate and bill impacts.

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

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

[33] Detailed calculations and data sources are available in *Appendix 1*.

[34] Ill. Power Agency, Ill. Commerce Comm'n Docket 09-0373, Motion for Leave to File Supplemental Recommendation for the Procurement Plan, Appendix K at 7 (Nov. 9, 2009).

- 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."[35]
- For the 2010 procurement, the ICC again agreed with the IPA's proposal to procure RECs on a short-term basis, for delivery from June 2010 – May 2011.[36] 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."[37]
- 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.[38]

For the 2012 procurement, to be conducted later this Spring, the IPA proposed 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, and the ICC agreed with the IPA's proposal.[39] Future REC purchase volumes for delivery beginning June 1, 2013 will be revised downward pursuant to Public Act 97-0616, which required the IPA to conduct the separate Rate Stability Procurement of renewable energy resources in February 2012.[40] 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.

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[35] Ill. Commerce Comm'n, Docket 08-0519, Final Order at 45 (Jan. 7, 2009).

[36] Ill. Commerce Comm'n, Docket 09-0373, Final Order at 127 (Dec. 28, 2009).

[37] Ill. Commerce Comm'n, Docket 09-0373, Final Order at 126, 115, 43 (Dec. 28, 2009).

[38] Ill. Commerce Comm'n, Docket 10-0563, Final Order at 83 (Dec. 21, 2010).

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

[40] Ill. Power Agency, Ill. Commerce Comm'n 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 2009-May 2012[41]	**0.743**	**3.412**
2010 LTPPA[42]	5.518	N/A
2012 Rate Stability[43]	0.128	3.257

Figure 2: Relative Cost Comparison of RECs and Conventional Supply on a Cents per Kilowatt-hour Basis for ComEd[44]

[41] Load-weighted average.

[42] The procurement cost noted for the long-term procurement reflects the average weighted price of delivery of bundled RECs and energy from renewable energy resources, including a 2% escalator each year. The entire contract term is June 2012 – May 2032. *See* ICC Approves Results of Renewable Energy RFP, News from the Ill. Commerce Comm'n (Dec. 15, 2010).

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

[44] 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[45] (¢/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 2009-May 2012[46]	**0.623**	**3.378**
2010 LTPPA[47]	5.044	N/A
2012 Rate Stability[48]	0.343	2.951

Figure 3: Relative Cost Comparison of RECs and Conventional Supply on a Cents per Kilowatt-hour Basis for Ameren[49]

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."[50]

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.

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

46 Load-weighted average.

47 The procurement cost noted for the long-term procurement reflects the average weighted price of delivery of bundled RECs and energy from renewable energy resources, including a 2% escalator each year. The entire contract term is June 2012 – May 2032. *See* ICC Approves Results of Renewable Energy RFP, News from the Ill. Commerce Comm'n (Dec. 15, 2010).

48 Load-weighted average of the first year of delivery, June 2013-May 2014.

49 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.

50 20 ILCS 3855/1-75(c)(5)(A).

1. Economic Benefits

Illinois currently ranks fourth in the country for overall installed wind capacity in the U.S. according to the American Wind Energy Association (AWEA).[51] AWEA also found that Illinois ranked second to California for most new wind energy capacity installed in 2011, and led the nation in number of new turbines installed with 404.[52] 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 may offset some of the purported benefits of this renewable energy resource, including government subsidization of the industry, reduced land values, wear and tear on local roads during the construction of turbines, future decommissioning costs, and that the variable nature of this resource could increase spinning reserve requirements. While the market modeling software applied by IPA's procurement planning consultant evaluates the impact of wind energy on spinning reserve requirements, the Agency is unaware of any method to accurately and reliably quantify the other negative impacts for comparison with alternative energy sources. Nevertheless, these impacts should be considered in any policy discussion regarding renewable energy resources.

a. Impact on Electricity Prices

General Price Impacts

Illinois State University's Center for Renewable Energy concluded that because wind is both an inexhaustible energy source and is free from fuel price volatility, it can contribute to the nation's energy security.[53] 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. [54] (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

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

[52] *Id.*

[53] *Economic Impact: Wind Energy Development in Illinois*, Center for Renewable Energy, Illinois State University (2011) at 10.

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

transportation difficulties or international conflict.[55] Likewise, wind power is not subject to the uncertainty surrounding future carbon taxes, unlike fossil fuel-fired power plants.[56]

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 Operators (RTO) 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 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.

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[55] *Id.*

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

The market price effects of renewable resources added to the interconnected electric system can be estimated using market modeling software. The IPA's procurement planning consultant, Adica, employs a proprietary market model[57] capable of modeling the entire Eastern Interconnection[58] 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 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. Furthermore, the model estimates that average LMPs were significantly affected by the integration of renewable resources into the power grid. Renewable resources have 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."[59]

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 Eenergy	2353.21	5788.84	4973.92	2301.53	36.4	873.58	1900.40
	With Renewable Energy	2244.04	5531.40	4797.07	2207.59	35.1	873.04	1868.90

Figure 4: Estimated LMP Savings From Renewable Resource Integration[60]

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

[58] The Eastern Interconnection includes MISO and PJM.

[59] "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).

[60] 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.

b. Economic Development

Illinois State University's Center for Renewable Energy modeled the economic impact of wind energy upon Illinois' economy by entering project specific information into the National Renewable Energy Laboratory's (NREL) Jobs and Economic Development Impact (JEDI) model to estimate the income, economic activity, and number of job opportunities accruing to the state from the project.[61] The report 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.[62] 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.[63]

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."[64] Indirect impacts occurred both in the construction and the operation of wind turbines, and included construction spending on materials and wind farm equipment and other purchases of goods and offsite services and "expenditures related to on-site labor, materials, and services needed to operate the wind farms (e.g., vehicles, site maintenance, fees, permits, licenses, utilities, insurance, fuel, tools and supplies, replacement parts/equipment); the supply chain of inputs required to produce these goods and services; and project revenues that flow to the local economy in the form of land lease revenue, property tax revenue, and revenue to equity investors."[65]

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.

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.

[61] Economic Impact: Wind Energy Development in Illinois at 17.

[62] Economic Impact: Wind Energy Development in Illinois at 23.

[63] *Id.*

[64] Economic Impact: Wind Energy Development in Illinois at 18.

[65] *Id.* at 19.

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.[66]

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,"[67] since local governments can receive significant amounts of revenue from permitting fees.[68] 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."[69] As noted above, however, the IPA believes that some local concerns such as wear and tear on roads during construction, unfunded decommissioning cost liability and possibly lowered land values should be considered when evaluating any specific project's impacts.

c. 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.[70]
- 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.[71]
- 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

[66] *Id*. at 20.

[67] *Id*. at 11.

[68] *Id*. at 16.

[69] *Id*. at 15.

[70] *Id*. at 13.

[71] 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 13-14.

per megawatt (MW) of capacity and annually adjusted for inflation according to the United States Consumer Price Index.[72] 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.[73]

At the federal level, the production tax credit (PTC) for wind energy is slated to expire at the end of 2012, and it is unclear whether it will be renewed. The PTC provides an income tax credit of 2.2 cents per kilowatt-hour for the production of electricity from utility-scale turbines. The incentive was created under the Energy Policy Act of 1992, and applies for the first 10 years of electricity production. Through Section 1603 of the American Recovery and Reinvestment Act of 2009, wind project developers can choose to receive a 30% investment tax credit (ITC) in place of the PTC. For projects placed in service before 2013, at which construction begins before the end of 2011, developers can elect to receive an equivalent cash payment from the Department of Treasury for the value of the 30% ITC. AWEA reports that in the years following expiration, installations dropped between 73 and 93 percent, with corresponding job losses.[74]

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), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) may reasonably be anticipated to endanger public health and welfare.[75] 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.[76] 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.[77]

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

[72] 35 ILCS 200/10-605.

[73] Economic Impact: Wind Energy Development in Illinois at 14.

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

[75] 74 Fed. Reg. 66,495 (Dec. 15, 2009).

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

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

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 the table 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).

Year	Renewable Energy Integration	CO2 (Ton)	NOx (Ton)	CO2 Cost ($)	NOx Cost ($)	Total Emission Cost ($)
2011	No Renewable Eenergy	90,386,907.82	78,114.40	451,934,539.12	781,143,959.14	1,233,078,498.27
	With Renewable Energy	84,905,580.47	73,349.79	424,527,902.36	733,497,897.58	1,158,025,799.94

Figure 5: Emissions Cost Savings From Renewable Resource Integration

C. Rate Impacts on Eligible Retail Customers

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

The IPA asked Ameren and ComEd to provide their rate spreadsheets by customer class for each of the three delivery years examined, breaking out the additional amounts reflected in the supply charge attributable to renewable resource delivery by delivery year.[79] These spreadsheets provide the rate impact associated with the Agency's procurement of renewable resources. When multiplied by the overall billing determinants, the values from the provided spreadsheets provide the total dollar impact on the annual electricity bills of each customer class. Results are presented for each electric utility and corresponding customer class below.

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

[79] These spreadsheets can be found at *Appendix 2*.

Because the 2010 LTPPA, the sole "long-term contract" procured by the IPA, begins delivery on June 1st of 2012, there are not yet any "rate impacts" or "total dollar impacts" on end-customer "annual electricity bills" that the Agency can analyze.

1. ComEd

	SF	MF	SFSH	MFSH	WH	Small Load
Rate Impact[80] June 2009 – May 2010	0.69%	0.61%	0.65%	0.61%	0.63%	0.81%
Total Dollar Impact June 2009 – May 2010	$18,582,034	$3,715,327	$438,849	$928,246	$458,803	$7,520,576
Rate Impact June 2010 – May 2011	0.21%	0.18%	0.20%	0.19%	0.20%	0.25%
Total Dollar Impact June 2010 – May 2011	$6,593,738	$1,389,117	$86,042	$167,408	$156,180	$2,406,481
Rate Impact June 2011 – May 2012	0.05%	0.05%	0.05%	0.05%	0.04%	0.06%
Total Dollar Impact June 2011 – May 2012	$1,479,872	$303,030	$36,246	$75,508	$31,140	$423,360

Figure 6: ComEd Rate and Total Dollar Impacts

[80] 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," except for taxes. Thus, a Rate Impact of 0.69% means that 0.69% of the total electricity bill (before taxes) of a customer of that class in that delivery year was spent on satisfying contracts for renewable energy resources.

2. Ameren

	DS-1 Rate Zone I	DS-1 Rate Zone II	DS-1 Rate Zone III	DS-2 Rate Zone I	DS-2 Rate Zone II	DS-2 Rate Zone III	DS-3 Rate Zone I	DS-3 Rate Zone II	DS-3 Rate Zone III
Rate Impact[81] June 2009 – May 2010	0.70%	0.69%	0.61%	0.63%	0.65%	0.58%	0.83%	0.78%	0.76%
Total Dollar Impact June 2009 – May 2010	$2,398,953	$1,264,776	$3,504,771	$852,750	$351,942	$1,127,579	$340,748	$98,348	$361,128
Rate Impact June 2010 – May 2011	0.22%	0.23%	0.19%	0.21%	0.22%	0.19%	0.28%	0.27%	0.25%
Total Dollar Impact June 2010 – May 2011	$847,848	$456,896	$1,248,348	$230,026	$100,738	$307,786	$50,575	$21,718	$59,270
Rate Impact[82] June 2011 – Feb. 2012	0.06%	0.06%	0.05%	0.06%	0.06%	0.05%	0.08%	0.08%	0.07%
Total Dollar Impact[83] June 2011 – Feb. 2012	$170,449	$94,818	$255,827	$42,353	$19,213	$56,506	$7,968	$3,679	$8,898

Values for Ameren customer class DS-5 were unavailable from Ameren at the time this report was compiled. Values for Ameren customer class QF are not available since Ameren is obligated to purchase energy *from* this class

Figure7: Ameren Rate and Total Dollar Impacts

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81 This value equals the ACP rate for the delivery year class divided by the total revenue per kilowatt-hour of the corresponding delivery year class. The ACP rate is equal to the amount Ameren spent on renewable resources in the delivery year divided by the forecasted load of eligible customers during that same period. *See* 220 ILCS 5/16-115D(d)(1). Thus, a Rate Impact of 0.70% means that 0.7% of the total electricity bill of a customer of that class in that delivery year was spent on satisfying contracts for renewable energy resources.

82 Because this year has not been fully delivered, Rate Impacts are provided until and including February 2012.

83 Because this year has not been fully delivered, Total Dollar Impacts are provided until and including February 2012.

D. Rate Impacts on Customers of Alternative Retail Electric Suppliers

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

An ARES may satisfy its RPS requirement entirely through 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.[85] 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 Report has estimated the ACP payment based on the actual published ACP rate and the estimated load of ARES customers.

Delivery Year[86]	ComEd Usage Forecast[87] (kWh)	ComEd ACP Rate (¢/kWh)	Ameren Usage Forecast[88] (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

Figure 8: Actual Published ACP Rates[89]

Assuming an ARES uses the ACP to meet half its RPS requirement, yet 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. 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, and assuming ARES pay approximately the same amount for renewable resources they directly procure, the bill impact on ARES and utility customers is similar in

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

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

[86] Because it has not been fully delivered, the ACP rate for delivery year 2011-2012 is not included in this estimate.

[87] This is the forecasted usage of all ComEd customers, not ARES customers.

[88] This is the forecasted usage of all Ameren customers, not ARES customers.

[89] RPS Alternative Compliance Payment Notices, Illinois Commerce Commission, http://www.icc.illinois.gov/downloads/public/ACP%20Rate%20History%20as%20of%202012-01-04.pdf (converted to kWh and cents per kWh).

dollar amount, although the percentage impact may be somewhat higher, given the lower energy prices currently available from ARES.

Because the 2010 LTPPA, the sole "long-term contract" procured by the IPA, begins delivery on June 1st of 2012, there are not yet any "rate impacts" or "total dollar impacts" on ARES customer bills that the Agency can analyze.

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."*[90]

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.[91] 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.[92] 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.[93] All ACPs are placed into the Agency's Renewable Energy Resources Fund ("RERF")[94] which could then to be used to purchase RECs.[95] 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.[96] 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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[90] 220 ILCS 5/16-115D(d)(4).

[91] 220 ILCS 5/16-115D(a).

[92] 220 ILCS 5/16-115D(a)(3) (the 60% statutory wind energy minimum for ARES is lower than the 75% wind standard for utilities).

[93] 220 ILCS 5/16-115D(b).

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

[95] 20 ILCS 3855/1-56.

[96] 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.[97] Under the PUA, a "planning year" begins on June 1st of each calendar year.[98] 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.[99] Therefore, this report must provide the aggregate total amount of ACPs for planning years June 2009 – May 2010 and June 2010 – May 2011.

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	$5,606,245.18
Aggregate Total		**$12,754,506.79**

Figure 9: 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.[100] The remaining $438,261.61 was not used to purchase RECs and remains in the RERF. The State is required to repay the borrowed funds within 18 months of borrowing. The State has repaid $2,000,000 to the RERF and the outstanding $4,710,000 is due for repayment by April 14, 2012. Because the funds were borrowed from a non-interest earning account, no interest has been or will be repaid. The IPA respectfully notes that this borrowing occurred despite legislation which states

> "The Illinois Power Agency Renewable Energy Resources Fund shall not be subject to sweeps, administrative charges, or chargebacks, including, but not limited to, those authorized under Section 8h of the State Finance Act, that would in any way result in the transfer of any funds from this fund to any

[97] 220 ILCS 5/16-115D(d)(4)(A).

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

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

[100] 30 ILCS 105/5h(a).

other fund of this State or in having any such funds utilized for any purpose other than the express purposes set forth in this Section."[101]

While the IPA believes that its use of the RERF is not subject to inclusion in its Procurement Plans, because the balance in the RERF was substantially depleted at the time the 2012 Procurement Plan was litigated and approved, there has been no stated plan regarding use of the RERF's initial deposits.

In the third quarter of 2011, the IPA received a total of $5,606,245.18 in ACPs for the June 2010 – May 2011 planning year which, to the extent the funds remain available, will be used in accordance with the IPA Act.[102] The IPA will consider using ACP funds within the context of its 2013 Procurement Plan. If the State continues to borrow funds from the RERF, the IPA's ability to purchase RECs at prices that "do not exceed the winning bid prices paid for like resources procured for electric utilities" will be limited.[103]

C. Balance in RERF attributable to ACPs

As of this report date, the RERF balance equals $8,044,506.79. The amount required to be repaid by the State by April 14, 2012 is $4,710,000. The sum of these two amounts equals $12,754,506.79, the total amount received in the Agency's RERF attributable to ACPs.

[101] 20 ILCS 3855/1-56(h).

[102] 20 ILCS 3855/1-56.

[103] 20 ILCS 3855/1-56(d).

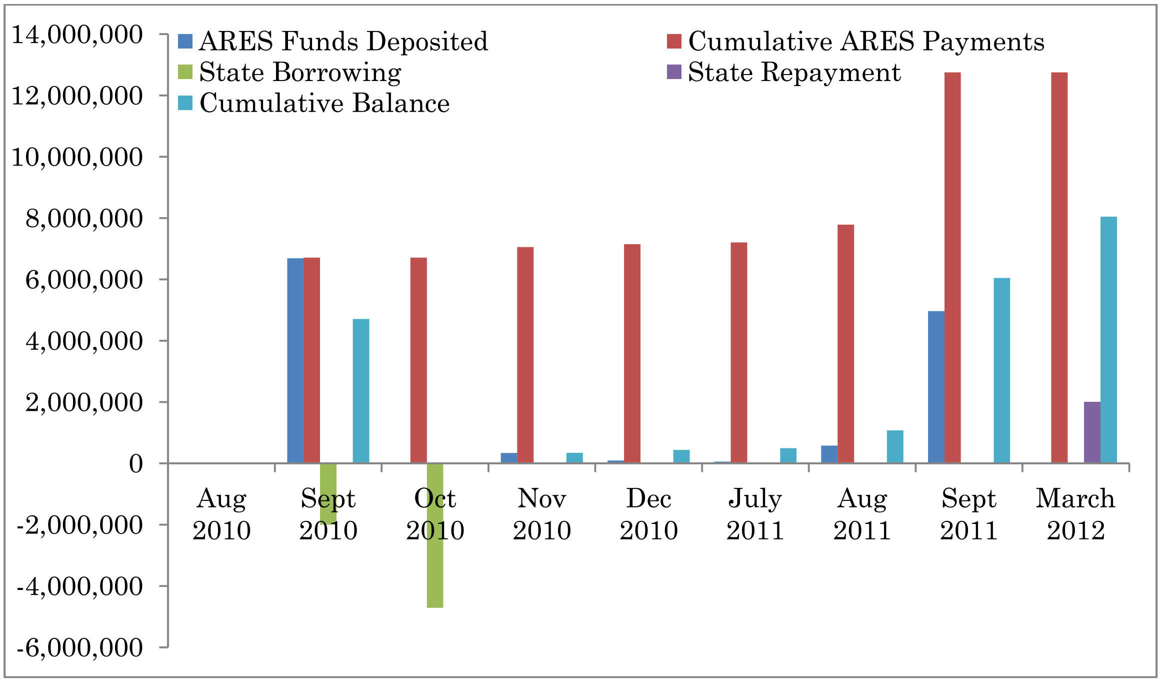


Figure 10: Illinois Power Agency Renewable Energy Resources Fund Transactions (Amounts in Dollars)

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	Anticipated repayment by State	$4,710,000	$12,754,506.79

Figure 11: 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. Despite the fact that the IPA believes it has the authority to use the RERF outside a Procurement Plan, there are several alternatives that deserve a full public vetting. The IPA intends to include an analysis and proposal to use the RERF to procure renewable resources in its 2013 Procurement Plan, to be filed in the fall of 2012. In particular, conducting parallel utility and ARES Distributed Generation procurements holds promise, as this is a currently unfulfilled mandate. The minimum required term for Distributed Generation contracts is 5 years. As a cautionary note, unless the General Assembly can prevent the "borrowing" of RERF monies, which serves to deplete the dollars available for their legislatively stated purpose, any long-term contractual arrangements based on the flow of funds from ACP monies could prevent the IPA from meeting its contractual obligations.

An alternative use of the RERF, to be examined in the 2013 Procurement Plan, may be to offset the migration risks posed by municipal aggregation to utility REC contract obligations. That is, as load shifts to ARES from utilities, it is appropriate for ARES-provided funding to assist with contractual purchase obligations for existing and future utility REC contracts.

One current legislative proposal does away with the ACP mechanism, instead requiring the IPA to facilitate RPS compliance for all retail electric customers regardless of supplier.[104] 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 risks related to the volume of procurement, it raises issues of monopsony and inefficient markets which should be further considered. Until legislative certainty is achieved around this proposal, it is not advisable to use RERF monies to underwrite long-term contracts for renewable resources.

[104] S. B. 678, 97th Gen. Assem. (Ill. 2011).

V. Appendices

Appendix 1a

Ameren Cost Comparison

Year	REC Load-Weighted Average (¢/kWh)	Conventional Load-Weighted Average (¢/kWh)
2009 - 2010[105]	1.5860	3.6824
2010 - 2011[106]	0.4046	3.1145
2011 - 2012[107]	0.0923	3.2337
Average	0.6230	3.3781

Figure 12: REC and Conventional Load-Weighted Average

IL - PV Price ($/MWh)	IL - PV Quantity (MWh)	IL - PV Expenditure ($)
95.26	8,065	768,272
OS - PV Price ($/MWh)	OS - PV Quantity (MWh)	OS - PV Expenditure ($)
99.54	5,100	507,654
Wind Price ($/MWh)	Wind Quantity (MWh)	Wind Expenditure ($)
1.13	415,655	469,690
Other Price ($/MWh)	Other Quantity (MWh)	Other Expenditure ($)
0.85	107,200	91,120
Load-Weighted Average ($/MWh)	Load-Weighted Average (¢/kWh)	
3.4266	0.3427	

Figure 13: 2013-2014 Rate Stability[108]

105 Data from ICC Public Notice (May 18, 2009); and computed from Figure 14 of this Report.

106 Data from ICC Public Notice (May 24, 2010); and computed from Figure 15 of this Report.

107 Data from ICC Public Notice (May 24, 2011); and computed from Figure 16 of this Report.

108 Data from IPA Public Notice (Feb. 23, 2012).

Date	On peak Price ($/MWh)	On Peak System Supply Requirements (MWh)	On Peak Residual Volume (MWh)	On Peak Expenditure ($)	Off Peak Price ($/MWh)	Off Peak System Supply Requirements (MWh)	Off Peak Residual Volume (MWh)	Off Peak Expenditure ($)	Total Residual Volume (MWh)	Total Residual Expenditure ($)	Total Capacity Expenditure ($)
Jun-09	34.12	961,143	292,380	9,975,995	20.57	718,067	218,436	4,493,228	510,816	14,469,224	581,386
Jul-09	42.81	1,156,240	351,728	15,057,485	25.22	892,476	271,491	6,847,008	623,219	21,904,493	15,107,085
Aug-09	43.85	1,034,569	314,716	13,800,292	25.59	955,653	290,710	7,439,260	605,426	21,239,552	11,685,572
Sep-09	32.89	848,033	257,972	8,484,687	21.86	794,887	241,805	5,285,849	499,776	13,770,536	367,043
Oct-09	33.18	785,985	239,097	7,933,226	21.48	687,040	208,998	4,489,268	448,094	12,422,494	103,854
Nov-09	30.64	700,927	213,222	6,533,122	22.58	771,588	234,717	5,299,911	447,939	11,833,033	94,486
Dec-09	34.34	883,473	268,752	9,228,960	24.46	842,242	256,210	6,266,897	524,963	15,495,857	131,169
Jan-10	46.72	828,389	251,996	11,773,250	30.20	982,115	298,759	9,022,533	550,755	20,795,783	183,316
Feb-10	45.36	777,887	236,633	10,733,683	29.61	771,204	234,600	6,946,514	471,233	17,680,197	142,547
Mar-10	39.57	795,758	242,070	9,578,693	27.27	707,592	215,249	5,869,853	457,319	15,448,547	97,047
Apr-10	38.51	688,661	209,491	8,067,486	27.08	601,379	182,939	4,954,001	392,430	13,021,487	82,286
May-10	36.58	630,902	191,920	7,020,448	22.28	683,187	207,825	4,630,352	399,746	11,650,800	119,724
Total		10,091,967	3,069,976	118,187,328		9,407,430	2,861,740	71,544,675	5,931,717	189,732,003	28,695,515

Figure 14: 2009 AIC IPA Energy and Capacity Procurement[109]

[109] Data from ICC Public Notices (April 13, 2009) and (May 5, 2009), IPA Procurement Plan Final Order (08-0519), using 30.42% residual factor (page 3) and total supply from IPA's Petition, Attachment E.

Date	On peak Price ($/MWh)	On Peak System Supply Requirements (MWh)	On Peak Residual Volume (MWh)	On Peak Expenditure ($)	Off Peak Price ($/MWh)	Off Peak System Supply Requirements (MWh)	Off Peak Residual Volume (MWh)	Off Peak Expenditure ($)	Total Residual Volume (MWh)	Total Residual Expenditure ($)	Total Capacity Expenditure ($)
Jun-10	33.09	779,952	209,183	6,921,870	21.85	680,221	182,435	3,986,211	391,618	10,908,080	36,357
Jul-10	42.47	962,074	258,028	10,958,460	24.57	923,346	247,641	6,084,549	505,670	17,043,009	662,415
Aug-10	42.59	972,635	260,861	11,110,058	24.70	891,295	239,045	5,904,419	499,906	17,014,477	478,826
Sep-10	33.96	742,449	199,125	6,762,279	20.71	684,079	183,470	3,799,663	382,595	10,561,942	26,346
Oct-10	33.04	616,307	165,294	5,461,298	19.63	631,933	169,484	3,326,979	334,778	8,788,278	13,950
Nov-10	33.17	636,263	170,646	5,660,319	21.29	643,953	172,708	3,676,957	343,354	9,337,277	14,063
Dec-10	35.91	854,143	229,081	8,226,304	23.32	774,962	207,845	4,846,941	436,926	13,073,245	21,879
Jan-11	41.51	817,614	219,284	9,102,482	30.14	925,975	248,346	7,485,163	467,631	16,587,645	21,682
Feb-11	41.19	721,585	193,529	7,971,464	29.39	744,639	199,712	5,869,541	393,241	13,841,004	19,124
Mar-11	37.67	713,785	191,437	7,211,437	23.89	647,218	173,584	4,146,919	365,021	11,358,356	16,961
Apr-11	37.14	554,568	148,735	5,524,023	22.58	563,412	151,107	3,411,998	299,842	8,936,021	13,015
May-11	35.50	558,272	149,729	5,315,364	20.13	596,638	160,018	3,221,169	309,747	8,536,532	13,512
Total		8,929,647	2,394,931	90,225,356		8,707,671	2,335,397	55,760,510	4,730,329	145,985,867	1,338,129

Figure 15: 2010 AIC IPA Energy and Capacity Procurement[110]

[110] Data from ICC Public Notices (April 5, 2010) and (May 6, 2010), IPA Procurement Plan (09-0373), using total supply requirements from page 22 and residual factor of 26.82% from page 4.

Date	On Peak Residual Volume (MWh)	On Peak Expenditure ($)	Off Peak Residual Volume (MWh)	Off Peak Expenditure ($)	Total Residual Volume (MWh)	Total Residual Expenditure ($)	Total Capacity Expenditure ($)
Jun-11	173,867	6,805,504	191,933	4,858,227	365,800	11,663,731	17,196
Jul-11	170,267	7,158,696	157,933	4,089,551	328,200	11,248,247	90,102
Aug-11	154,267	6,445,736	174,333	4,529,555	328,600	10,975,291	74,138
Sep-11	169,067	6,306,592	175,133	4,392,075	344,200	10,698,667	6,800
Oct-11	135,467	4,963,264	136,733	3,537,291	272,200	8,500,555	3,960
Nov-11	152,267	5,558,992	136,733	3,537,291	289,000	9,096,283	2,372
Dec-11	152,267	5,578,144	177,533	4,546,275	329,800	10,124,419	2,333
Jan-12	185,867	7,395,064	175,133	4,675,467	361,000	12,070,531	3,230
Feb-12	185,867	7,420,768	175,133	4,675,467	361,000	12,096,235	2,836
Mar-12	154,267	5,848,896	156,333	4,044,735	310,600	9,893,631	1,551
Apr-12	154,267	5,848,896	136,733	3,537,291	291,000	9,386,187	1,850
May-12	138,667	5,215,872	136,733	3,537,291	275,400	8,753,163	3,008
Total	1,926,400	74,546,424	1,930,400	49,960,520	3,856,800	124,506,944	209,375

Figure 16: 2011 AIC IPA Energy and Capacity Procurement[111]

[111] Data from ICC Public Notices (May 9, 2011) and (May 13, 2011), IPA Procurement Plan (09-0373), using total supply requirements from page 22 and residual factor of 26.82% from page 4.

Appendix 1b

ComEd Cost Comparison

Year	REC Load-Weighted Average (¢/kWh)	Conventional Load-Weighted Average (¢/kWh)
2009 - 2010[112]	1.9270	3.2810
2010 - 2011[113]	0.4879	3.3440
2011 - 2012[114]	0.0950	3.6838
Average	0.7428	3.4125

Figure 17: REC and Conventional Load-Weighted Average

IL - PV Price ($/MWh)	IL - PV Quantity (MWh)	IL - PV Expenditure ($)
74.49	8	596
OS - PV Price ($/MWh)	OS - PV Quantity (MWh)	OS - PV Expenditure ($)
65	1,500	97,500
Wind Price ($/MWh)	Wind Quantity (MWh)	Wind Expenditure ($)
1.27	1,060,901	1,347,344
Other Price ($/MWh)	Other Quantity (MWh)	Other Expenditure ($)
0.97	277,500	269,175
Load-Weighted Average ($/MWh)	Load-Weighted Average (¢/kWh)	
1.2797	0.1280	

Figure 18: 2013-2014 Rate Stability[115]

[112] Data from ICC Public Notice (May 11, 2009); and computed from Figure 19 of this Report.

[113] Data from ICC Public Notice (May 24, 2010); and computed from Figure 20 of this Report.

[114] Data from ICC Public Notice (May 24, 2011); and computed from Figure 21 of this Report.

[115] Data from IPA Public Notice (Feb. 23, 2012).

Date	On peak Price ($/MWh)	On Peak Residual Volume (MWh)	On Peak Expenditure ($)	Off Peak Price ($/MWh)	Off Peak Residual Volume (MWh)	Off Peak Expenditure ($)	Total Volume (MWh)	Total Expenditure ($)
Jun-09	36.23	721,181	26,128,388	22.07	510,645	11,269,935	1,231,826	37,398,323
Jul-09	43.27	992,034	42,925,311	26.10	784,667	20,479,809	1,776,701	63,405,120
Aug-09	43.34	810,809	35,140,462	26.05	769,250	20,038,963	1,580,059	55,179,425
Sep-09	35.54	580,250	20,622,085	22.73	419,924	9,544,873	1,000,174	30,166,958
Oct-09	36.10	441,695	15,945,190	23.99	295,132	7,080,217	736,827	23,025,406
Nov-09	36.05	498,817	17,982,353	24.54	424,534	10,418,064	923,351	28,400,417
Dec-09	36.41	738,250	26,879,683	24.64	612,182	15,084,164	1,350,432	41,963,847
Jan-10	42.45	684,512	29,057,534	26.66	687,473	18,328,030	1,371,985	47,385,565
Feb-10	42.04	603,290	25,362,312	26.63	490,520	13,062,548	1,093,810	38,424,859
Mar-10	38.05	530,144	20,171,979	25.27	366,810	9,269,289	896,954	29,441,268
Apr-10	37.81	365,296	13,811,842	25.05	231,537	5,800,002	596,833	19,611,844
May-10	36.21	385,066	13,943,240	21.39	320,393	6,853,206	705,459	20,796,446
Total		7,351,344	287,970,378		5,913,067	147,229,099	13,264,411	435,199,477

Figure 19: 2009 ComEd IPA Energy Procurement[116]

[116] Data from ICC Public Notices (April 29, 2009), ICC Final Order approving IPA Procurement Plan (08-0519).

Date	On peak Price ($/MWh)	On Peak Residual Volume (MWh)	On Peak Expenditure ($)	Off Peak Price ($/MWh)	Off Peak Residual Volume (MWh)	Off Peak Expenditure ($)	Total Volume (MWh)	Total Expenditure ($)
Jun-10	39.30	509,703	20,031,315	22.65	436,381	9,884,027	946,084	29,915,342
Jul-10	45.71	599,535	27,404,732	26.65	590,385	15,733,773	1,189,920	43,138,506
Aug-10	45.53	582,879	26,538,473	26.39	529,131	13,963,768	1,112,010	40,502,240
Sep-10	38.69	426,793	16,512,606	22.76	406,445	9,250,683	833,237	25,763,288
Oct-10	38.07	364,725	13,885,072	23.64	380,340	8,991,238	745,065	22,876,310
Nov-10	38.05	403,491	15,352,820	23.60	403,236	9,516,362	806,726	24,869,182
Dec-10	39.08	514,944	20,124,009	24.92	455,622	11,354,106	970,566	31,478,115
Jan-11	43.20	470,869	20,341,556	29.92	507,020	15,170,046	977,890	35,511,601
Feb-11	43.03	418,632	18,013,731	29.84	409,173	12,209,710	827,805	30,223,442
Mar-11	41.68	429,896	17,918,080	25.15	389,909	9,806,204	819,805	27,724,284
Apr-11	39.88	349,666	13,944,692	24.12	352,462	8,501,393	702,129	22,446,085
May-11	39.25	357,403	14,028,056	21.68	376,142	8,154,767	733,545	22,182,823
Total		5,428,535	224,095,142		5,236,246	132,536,076	10,664,781	356,631,218

Figure 20: 2010 ComEd IPA Energy Procurement[117]

[117] Data from ICC Public Notices (April 30, 2010), ICC Final Order approving IPA Procurement Plan (09-0373).

Date	On Peak Residual Volume (MWh)	On Peak Expenditure ($)	Off Peak Residual Volume (MWh)	Off Peak Expenditure ($)	Total Volume (MWh)	Total Expenditure ($)
Jun-11	542,400	24,480,544	281,667	7,357,700	824,067	31,838,244
Jul-11	493,200	24,781,164	604,867	17,878,276	1,098,067	42,659,440
Aug-11	466,000	23,274,492	534,067	15,754,912	1,000,067	39,029,404
Sep-11	455,200	19,077,048	289,667	7,001,780	744,867	26,078,828
Oct-11	287,200	11,488,488	97,667	2,560,820	384,867	14,049,308
Nov-11	438,400	17,134,296	270,467	6,500,660	708,867	23,634,956
Dec-11	472,000	19,094,856	505,667	13,519,700	977,667	32,614,556
Jan-12	505,600	22,341,456	504,467	16,077,884	1,010,067	38,419,340
Feb-12	472,000	20,667,168	443,267	14,010,548	915,267	34,677,716
Mar-12	415,600	17,076,312	274,067	7,399,472	689,667	24,475,784
Apr-12	257,200	10,624,680	97,667	2,560,820	354,867	13,185,500
May-12	313,600	12,722,688	97,667	2,560,820	411,267	15,283,508
Total	5,118,400	222,763,192	4,001,200	113,183,392	9,119,600	335,946,584

Figure 21: 2011 ComEd IPA Energy Procurement[118]

[118] Data from ICC Public Notice (May 18 2011).

Appendix 2a

Ameren Rate Impacts

		2009 Plan Year	2010 Plan Year	2011 Plan Year Thru February	ACP Rate 2009 Plan Year	ACP Rate 2010 Plan Year	ACP Rate 2011 Plan Year Thru February	Ratio for 2009 Plan Year	Ratio for 2010 Plan Year	Ratio for 2011 Plan Year Thru February
	Rate Zone I	**Revenue/kWh**	**Revenue/kWh**	**Revenue/kWh**	**REC/kWh**	**REC/kWh**	**REC/kWh**	**%**	**%**	**%**
Fixed Price	BGS-1	$0.093	$0.097	$0.097	$0.000645	$0.000211	$0.000058	0.70%	0.22%	0.06%
	BGS-2	$0.102	$0.100	$0.104	$0.000645	$0.000211	$0.000058	0.63%	0.21%	0.06%
	BGS-3	$0.078	$0.076	$0.076	$0.000645	$0.000211	$0.000058	0.83%	0.28%	0.08%
	Rate Zone II									
Fixed Price	BGS-1	$0.093	$0.092	$0.091	$0.000645	$0.000211	$0.000058	0.69%	0.23%	0.06%
	BGS-2	$0.099	$0.095	$0.098	$0.000645	$0.000211	$0.000058	0.65%	0.22%	0.06%
	BGS-3	$0.083	$0.078	$0.077	$0.000645	$0.000211	$0.000058	0.78%	0.27%	0.08%
	Rate Zone III									
Fixed Price	BGS-1	$0.105	$0.110	$0.110	$0.000645	$0.000211	$0.000058	0.61%	0.19%	0.05%
	BGS-2	$0.111	$0.109	$0.113	$0.000645	$0.000211	$0.000058	0.58%	0.19%	0.05%
	BGS-3	$0.085	$0.083	$0.084	$0.000645	$0.000211	$0.000058	0.76%	0.25%	0.07%

Figure 22: Ameren Rate Impact

		2009 Plan Year		2010 Plan Year		2011 Plan Year thru February	
	Rate Zone I	**Usage (kWh)**	**Dollar Impact**	**Usage (kWh)**	**Dollar Impact**	**Usage (kWh)**	**Dollar Impact**
Fixed Price	BGS-1	3,719,306,247	$2,398,953	4,018,238,879	$847,848	2,938,771,840	$170,449
	BGS-2	1,322,093,641	$852,750	1,090,170,287	$230,026	730,218,940	$42,353
	BGS-3	528,291,793	$340,748	239,691,632	$50,575	137,385,492	$7,968
	Rate Zone II						
Fixed Price	BGS-1	1,960,893,127	$1,264,776	2,165,385,392	$456,896	1,634,800,380	$94,818
	BGS-2	545,645,845	$351,942	477,428,939	$100,738	331,250,507	$19,213
	BGS-3	152,477,087	$98,348	102,928,279	$21,718	63,435,342	$3,679
	Rate Zone III						
Fixed Price	BGS-1	5,433,753,012	$3,504,771	5,916,341,378	$1,248,348	4,410,818,551	$255,827
	BGS-2	1,748,185,211	$1,127,579	1,458,701,530	$307,786	974,233,854	$56,506
	BGS-3	559,888,368	$361,128	280,899,066	$59,270	153,420,259	$8,898

Figure 23: Ameren Total Dollar Impact

Appendix 2b

ComEd Rate Impacts

Year	Jun-09		Jun-10		Jun-11	
Customer Group or Subgroup	Summer PEC (¢/kWh)	Non-summer PEC (¢/kWh)	Summer PEC (¢/kWh)	Non-summer PEC (¢/kWh)	Summer PEC (¢/kWh)	Non-summer PEC (¢/kWh)
Residential Non-Electric Space Heating	6.589	6.435	7.837	7.653	7.154	6.986
Residential Electric Space Heating	5.240	3.978	6.233	4.731	5.690	4.319
Watt-hour Non-Electric Space Heating	6.740	6.551	7.953	7.730	7.308	7.104
Demand Non-Electric Space Heating	6.646	6.507	7.842	7.679	7.207	7.056
Nonresidential Electrical Space Heating	6.337	6.234	7.478	7.357	6.871	6.760
Dusk to Dawn Lighting	2.398	2.865	2.844	3.398	2.590	3.093
General Lighting	6.265	6.245	7.430	7.407	6.765	6.743

Figure 24: ComEd Rate Impact: Purchased Electricity Charges (PECs)

Year	Jun-09		Jun-10		Jun-11	
Customer Group or Subgroup	Summer PEC (¢/kWh)	Non-summer PEC (¢/kWh)	Summer PEC (¢/kWh)	Non-summer PEC (¢/kWh)	Summer PEC (¢/kWh)	Non-summer PEC (¢/kWh)
Residential Non-Electric Space Heating	6.511	6.359	7.810	7.628	7.147	6.980
Residential Electric Space Heating	5.179	3.931	6.212	4.715	5.685	4.315
Watt-hour Non-Electric Space Heating	6.661	6.474	7.926	7.704	7.302	7.097
Demand Non-Electric Space Heating	6.568	6.431	7.815	7.652	7.200	7.050
Nonresidential Electrical Space Heating	6.262	6.161	7.452	7.331	6.865	6.754
Dusk to Dawn Lighting	2.370	2.831	2.835	3.386	2.587	3.090
General Lighting	6.192	6.172	7.405	7.381	6.759	6.737

Figure 25: ComEd Rate Impact: Illustrative PECs Without RECs

Year	Jun-09		Jun-10		Jun-11	
Customer Group or Subgroup	Summer PEC (¢/kWh)	Non-summer PEC (¢/kWh)	Summer PEC (¢/kWh)	Non-summer PEC (¢/kWh)	Summer PEC (¢/kWh)	Non-summer PEC (¢/kWh)
Residential Non-Electric Space Heating	0.078	0.076	0.027	0.025	0.007	0.006
Residential Electric Space Heating	0.061	0.047	0.021	0.016	0.005	0.004
Watt-hour Non-Electric Space Heating	0.079	0.077	0.027	0.026	0.006	0.007
Demand Non-Electric Space Heating	0.078	0.076	0.027	0.027	0.007	0.006
Nonresidential Electrical Space Heating	0.075	0.073	0.026	0.026	0.006	0.006
Dusk to Dawn Lighting	0.028	0.034	0.009	0.012	0.003	0.003
General Lighting	0.073	0.073	0.025	0.026	0.006	0.006

Figure 26: ComEd Rate Impact: Calculated REC

	Jun-09			Jun-10			Jun-11		
	Annual Average Overall Bill ¢/kWh			Annual Average Overall Bill ¢/kWh			Annual Average Overall Bill ¢/kWh		
Residential Delivery Classes	With RECs	Without RECs	RECs as % of Total Bill	With RECs	Without RECs	RECS as % of Total Bill	With RECs	Without RECs	RECS as % of Total Bill
Single Family No Electric Space Heat	11.19	11.12	0.69%	12.55	12.52	0.21%	12.53	12.53	0.05%
Multi Family No Electric Space Heat	12.56	12.49	0.61%	13.96	13.94	0.18%	13.70	13.70	0.05%
Single Family With Electric Space Heat	7.67	7.62	0.65%	8.56	8.55	0.20%	8.07	8.07	0.05%
Multi Family With Electric Space Heat	8.21	8.16	0.61%	9.19	9.17	0.19%	8.56	8.56	0.05%
Overall Residential	11.11	11.04	0.67%	12.46	12.44	0.20%	12.36	12.35	0.05%
Nonresidential Delivery Classes									
Watthour	12.46	12.38	0.63%	13.81	13.79	0.20%	14.29	14.28	0.04%
Small Load (≤ 100 kW)	9.49	9.41	0.81%	10.72	10.69	0.25%	10.66	10.66	0.06%

Figure 27: ComEd Rate Impact: Calculated Bill Impacts of RECs[119]

[119] Overall bill includes fixed supply charges, PJM services charges, delivery services charges (customer charge, standard metering service charges, distribution facilities charges), other environmental cost recovery and energy efficiency & demand adjustments, and franchise cost additions. Municipal and state taxes are excluded.

	Jun-09			Jun-10			Jun-11		
	Annual Average Overall Bill ¢/kWh			Annual Average Overall Bill ¢/kWh			Annual Average Overall Bill ¢/kWh		
Residential Delivery Classes	With RECs	Without RECs	Total Dollar Impact	With RECs	Without RECs	Total Dollar Impact	With RECs	Without RECs	Total Dollar Impact
Single Family No Electric Space Heat	11.19	11.12	18,582,034	12.55	12.52	6,593,738	12.53	12.53	1,479,872
Multi Family No Electric Space Heat	12.56	12.49	3,715,327	13.96	13.94	1,389,117	13.70	13.70	303,030
Single Family With Electric Space Heat	7.67	7.62	438,849	8.56	8.55	86,042	8.07	8.07	36,246
Multi Family With Electric Space Heat	8.21	8.16	928,246	9.19	9.17	167,409	8.56	8.56	75,508
Overall Residential	11.11	11.04		12.46	12.44		12.36	12.35	
Nonresidential Delivery Classes									
Watthour	12.46	12.38	458,803	13.81	13.79	156,180	14.29	14.28	31,140
Small Load (≤ 100 kW)	9.49	9.41	7,520,576	10.72	10.69	2,406,481	10.66	10.66	423,360

Figure 28: ComEd Total Dollar Impact: Calculated Bill Impacts of RECs[120]

[120] From Figure 27 and IPA Procurement Plan Load Forecasts.

Appendix 3

Market Price Simulator (MarSi™)

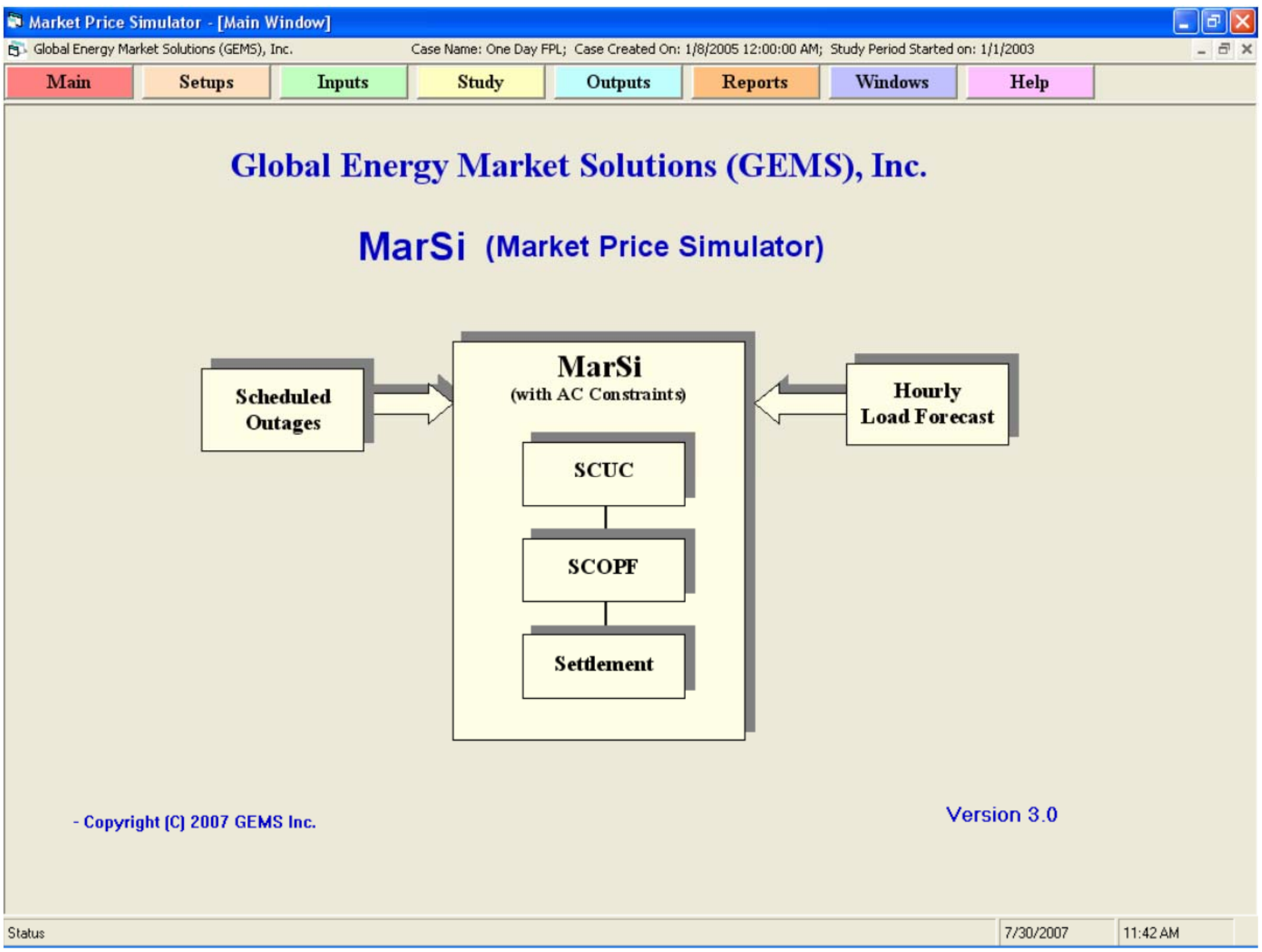
Market Price Simulator (MarSi™)

1. Introduction to MarSi

MarSi is a simulation software package for the actual operation of integrated electricity and natural gas systems under a wide range of operating conditions. MarSi is developed by Global Energy Market Solutions (GEMS), Inc. and runs on a single Windows-based computer. MarSi can optimize security constrained short-term and long-term generation scheduling, resource allocation, and integrated generation and transmission maintenance scheduling. MarSi can be used in an electricity market environment or by a vertically integrated utility for assessing the power system operation strategies and identifying system bottlenecks that stem out of the interdependency of electricity and gas infrastructures. The modeling capabilities, input/output characteristics, and potential applications of MarSi are outlined as follows.

Modules of MarSi™

- AC Security-Constrained Unit Commitment (SCUC)
- AC Security-Constrained Optimal Power Flow (SCOPF) and Settlement
- LMP Calculation and Settlement



2. Modeling Capabilities of MarSi

MarSi has unique capabilities for the short-term modeling of generating units, electricity network, and gas network.

1. Generation Resource Management

MarSi has the capability of modeling various types of generation units with very detailed operating constraints. MarSi accepts both hourly generation bids (stepwise or piecewise linear, for market-based operation) and generation cost curve (quadratic or piecewise-linear, for integrated utilities).

- Generation Unit Data
  - ❖ Scheduled outage parameters
  - ❖ Thermal units: generation limits, incremental heat rate curves, minimum up/down times, ramp up/down rates, start-up cost characteristics, multiple emission constraints, multiple fuel constraints, must on/off, and other operating constraints
  - ❖ Wind and Pumped-storage hydro units: Wind unit characteristics, water-conversion coefficients, volume limits, initial and terminal volumes, discharge limits, cycle efficiency
  - ❖ Combined-cycle units: generation limits, incremental heat rate curves, minimum up/down times, ramp up/down rates, start-up cost characteristics for each CT/ST configuration, multiple-emission constraints, multiple-fuel constraints, must on/off, and other operating constraints
  - ❖ Fuel switching units: heat rate curve for each possible fuel, generating capacity, minimum up/down time, ramp up/down rates, start-up cost characteristics for each fuel type, fuel and emission constraints, must on/off conditions
  - ❖ Cascaded hydro units: topology, water-conversion coefficients, volume limits, initial and terminal volumes, discharge limits, natural inflows, spillage, delay times
  - ❖ Generation outage schedule
- System Level Data
  - ❖ Hourly load forecast
  - ❖ Spinning reserve requirements
  - ❖ Operating reserve requirements
  - ❖ Interruptible loads (cost and schedule)
  - ❖ Fuel constraints (for all fuel types and individual units)
  - ❖ Regional emission limits

2. Transmission System Management

MarSi has the capability of modeling full ac electricity network constraints.

- Line flow and bus voltage limits
- Tap-changing and phase-shifting transformers
- Multiple contingencies constraints
- Preventive action and corrective actions for transmission system security
- Transmission outage schedule

3. Gas Network Management

MarSi has the capability of modeling a comprehensive gas network pipelines and gas network constraints.

- Each pipeline is modeled by several firm and interruptible gas contracts
- Each pipeline may feed several units / generating plants
- Location of pumping stations and pipeline distances (units further down can only burn a percentage of the total gas in the pipeline)
- Daily and hourly gas limits for each pipeline, each sub-area, each plant, and each unit.

3. Output Capabilities of MarSi

MarSi optimizes the hourly operating modes of generating units and determines fuel allocations depending on generating unit, electricity network, and gas network constraints. Typical output from MarSi include

- Hourly commitment and MW generation dispatch of generating units
- Hourly operating mode (combination of CTs and ST) for combined-cycle units
- Hourly fuel allocation (gas or oil) for each unit with fuel-switching capabilities
- List of constrained electricity transmission lines
- Short-term gas consumptions per pipeline, gas contract, subarea, plant, generating unit
- List of binding gas constraints for pipelines, gas contracts, subarea, plant, and generating unit
- Fuel and emission allowance allocation
- Simulation of long-term locational marginal price (LMP)
- LMP-based market scenario analyses.

4. Potential Applications of MarSi

MarSi can be used in a wide variety of scenarios.

(1) Market environment

MarSi can be used by RTOs/ISOs for the daily market simulation as well as the coordination of generation and transmission outage management.

- Provide market clearing and settlement for the day-ahead market (maximizing social welfare)
- Optimize long-term generation and transmission outage management.

(2) Integrated utilities

MarSi can be used by vertically integrated utilities for the simulation of optimal daily operation and the coordination of long-term maintenance scheduling constraints with short-term operation constraints

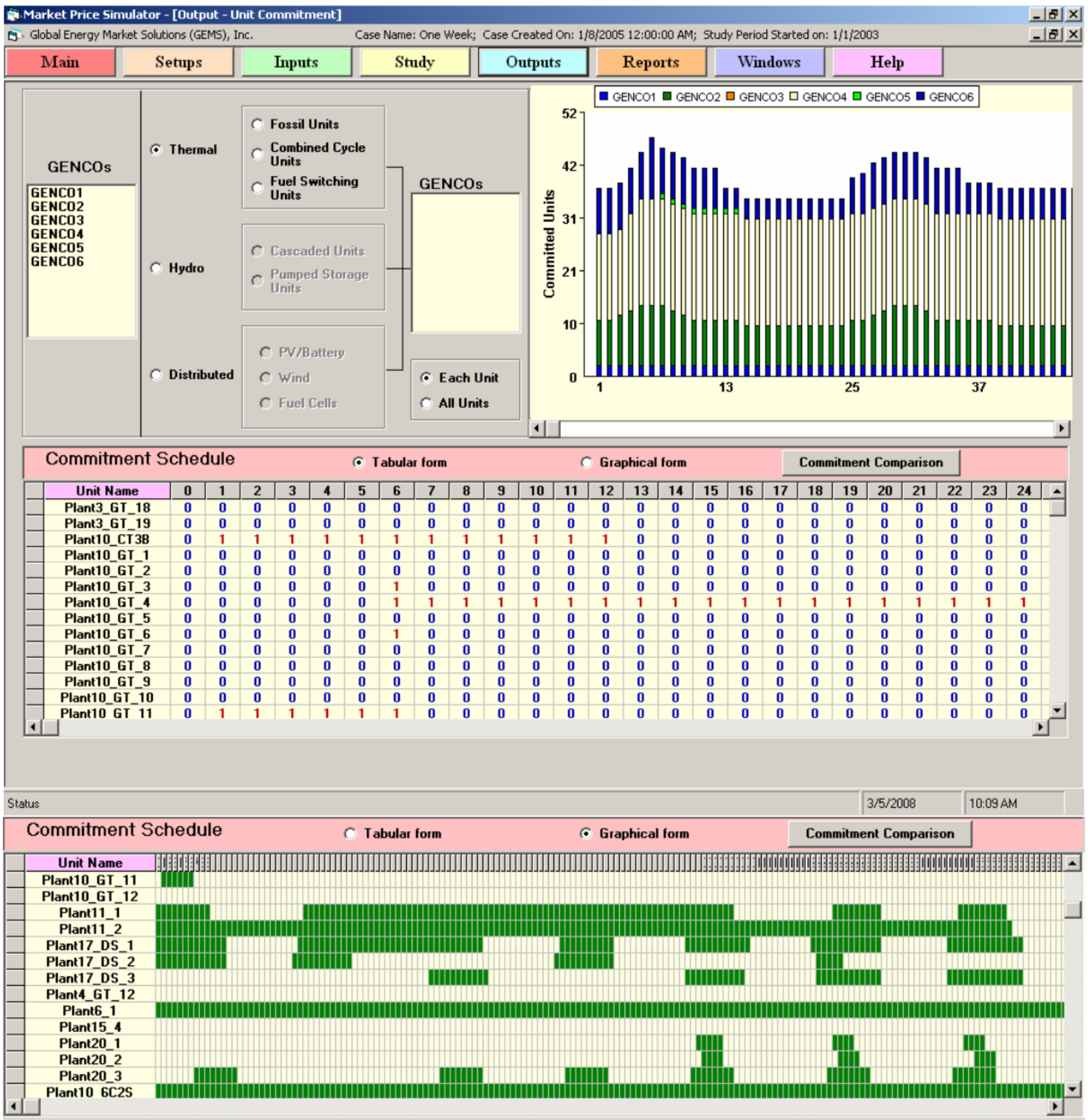
- Providing optimal day-ahead or long-term unit commitment and fuel schedule to minimize system operating cost
- Providing optimal long-term generation and transmission maintenance schedules.

(3) Simulation of interdependencies

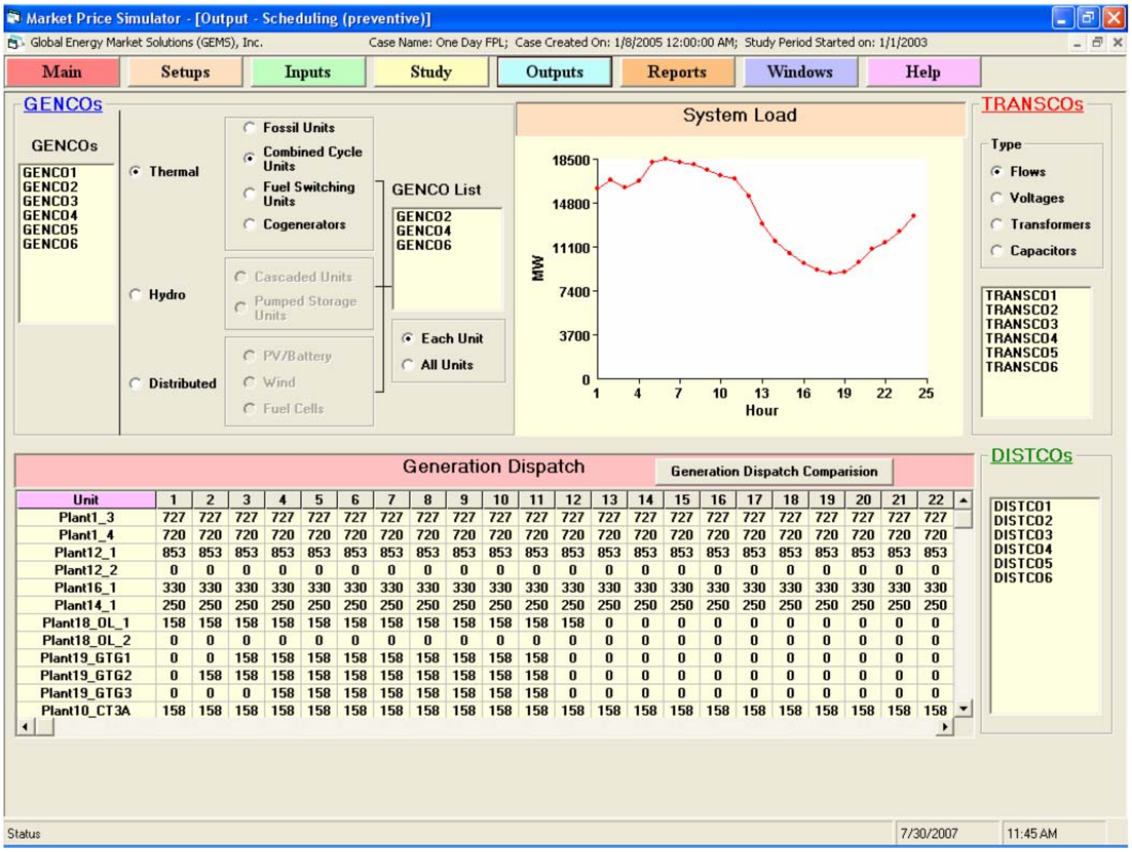
MarSi can be used to simulate the interdependency of electricity and natural gas infrastructures for supporting the social sustainability of energy systems. The following electric supply risk constraints are examples of such interdependencies that can be simulated by MarSi:

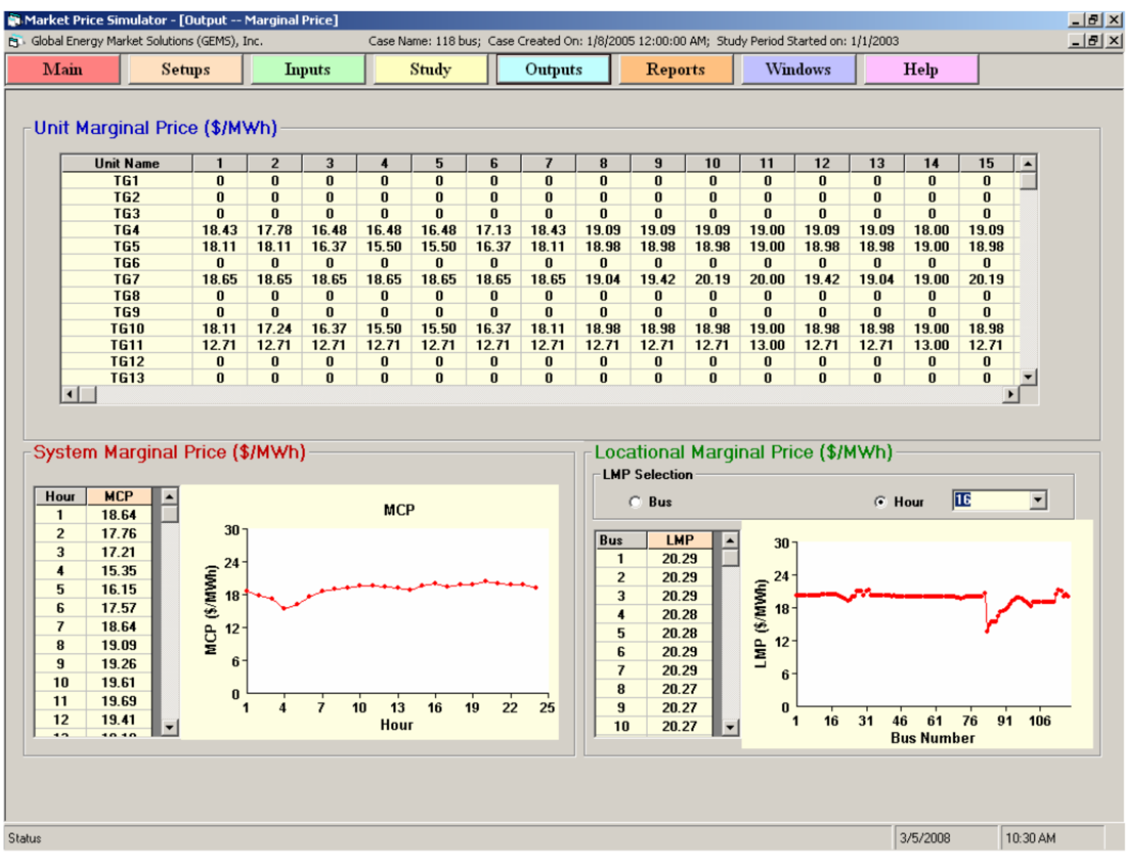
- Limited gas supply or interruptible gas contracts may impact the dispatch of gas-fired generating units without dual fuel capability
- An interruption or pressure loss in gas transmission systems could lead to a loss of multiple gas-fired electric generators and their hourly dispatch
- Outages in gas transmission systems, and inconsistent strategies for the control, monitoring, and curtailment of energy system infrastructure could lead to additional outages and further constrain the daily operation of power systems.

Hourly Unit Commitment

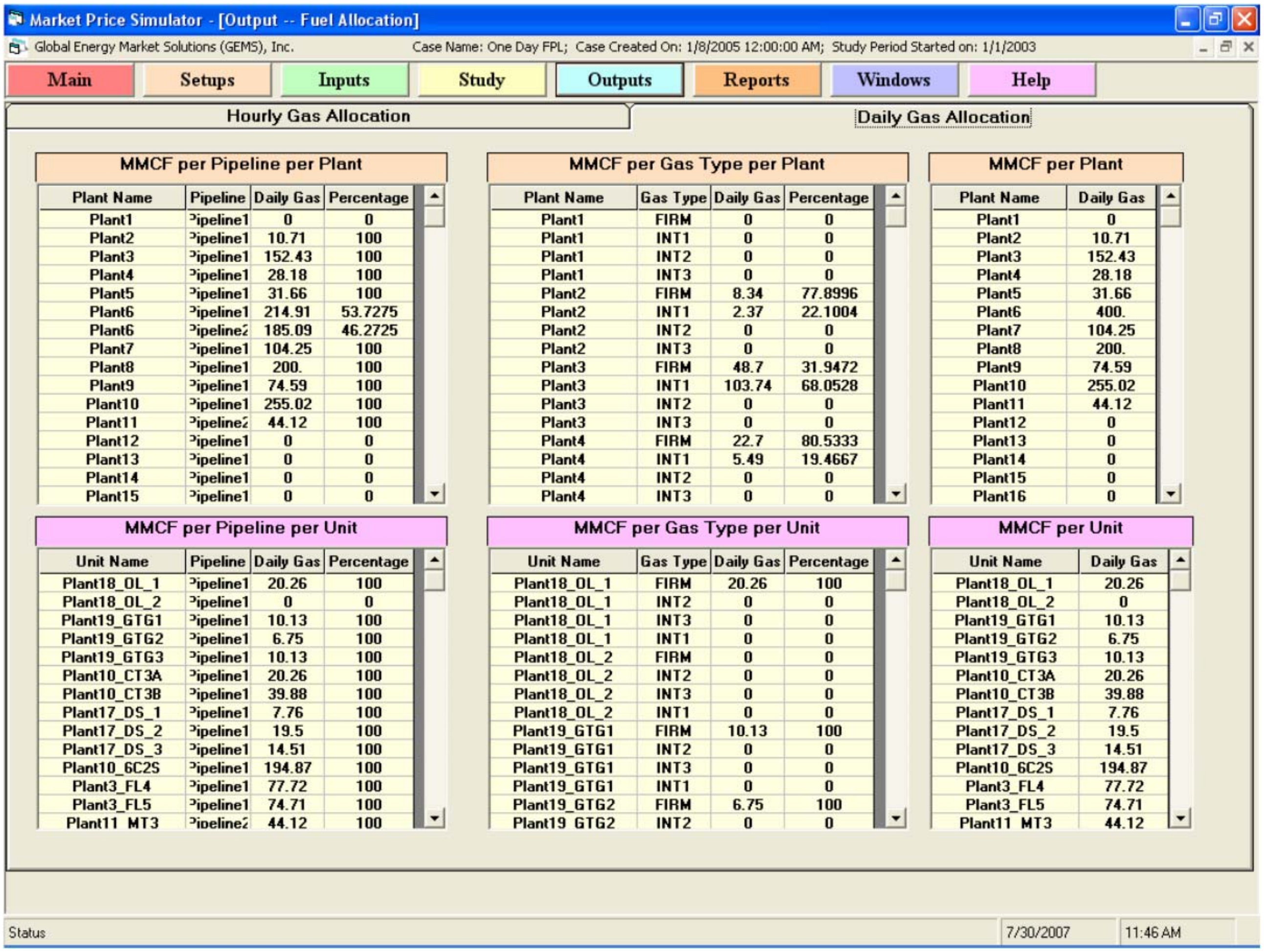


Hourly Security-constrained Dispatch and LMPs





Hourly Gas Allocation



MMCF per Pipeline per Plant

Plant Name	Pipeline	Daily Gas	Percentage
Plant1	Pipeline1	0	0
Plant2	Pipeline1	10.71	100
Plant3	Pipeline1	152.43	100
Plant4	Pipeline1	28.18	100
Plant5	Pipeline1	31.66	100
Plant6	Pipeline1	214.91	53.7275
Plant6	Pipeline2	185.09	46.2725
Plant7	Pipeline1	104.25	100
Plant8	Pipeline1	200.	100
Plant9	Pipeline1	74.59	100
Plant10	Pipeline1	255.02	100
Plant11	Pipeline2	44.12	100
Plant12	Pipeline1	0	0
Plant13	Pipeline1	0	0
Plant14	Pipeline1	0	0
Plant15	Pipeline1	0	0

MMCF per Gas Type per Plant

Plant Name	Gas Type	Daily Gas	Percentage
Plant1	FIRM	0	0
Plant1	INT1	0	0
Plant1	INT2	0	0
Plant1	INT3	0	0
Plant2	FIRM	8.34	77.8996
Plant2	INT1	2.37	22.1004
Plant2	INT2	0	0
Plant2	INT3	0	0
Plant3	FIRM	48.7	31.9472
Plant3	INT1	103.74	68.0528
Plant3	INT2	0	0
Plant3	INT3	0	0
Plant4	FIRM	22.7	80.5333
Plant4	INT1	5.49	19.4667
Plant4	INT2	0	0
Plant4	INT3	0	0

MMCF per Plant

Plant Name	Daily Gas
Plant1	0
Plant2	10.71
Plant3	152.43
Plant4	28.18
Plant5	31.66
Plant6	400.
Plant7	104.25
Plant8	200.
Plant9	74.59
Plant10	255.02
Plant11	44.12
Plant12	0
Plant13	0
Plant14	0
Plant15	0
Plant16	0

MMCF per Pipeline per Unit

Unit Name	Pipeline	Daily Gas	Percentage
Plant18_OL_1	Pipeline1	20.26	100
Plant18_OL_2	Pipeline1	0	0
Plant19_GTG1	Pipeline1	10.13	100
Plant19_GTG2	Pipeline1	6.75	100
Plant19_GTG3	Pipeline1	10.13	100
Plant10_CT3A	Pipeline1	20.26	100
Plant10_CT3B	Pipeline1	39.88	100
Plant17_DS_1	Pipeline1	7.76	100
Plant17_DS_2	Pipeline1	19.5	100
Plant17_DS_3	Pipeline1	14.51	100
Plant10_6C2S	Pipeline1	194.87	100
Plant3_FL4	Pipeline1	77.72	100
Plant3_FL5	Pipeline1	74.71	100
Plant11_MT3	Pipeline2	44.12	100

MMCF per Gas Type per Unit

Unit Name	Gas Type	Daily Gas	Percentage
Plant18_OL_1	FIRM	20.26	100
Plant18_OL_1	INT2	0	0
Plant18_OL_1	INT3	0	0
Plant18_OL_1	INT1	0	0
Plant18_OL_2	FIRM	0	0
Plant18_OL_2	INT2	0	0
Plant18_OL_2	INT3	0	0
Plant18_OL_2	INT1	0	0
Plant19_GTG1	FIRM	10.13	100
Plant19_GTG1	INT2	0	0
Plant19_GTG1	INT3	0	0
Plant19_GTG1	INT1	0	0
Plant19_GTG2	FIRM	6.75	100
Plant19_GTG2	INT2	0	0

MMCF per Unit

Unit Name	Daily Gas
Plant18_OL_1	20.26
Plant18_OL_2	0
Plant19_GTG1	10.13
Plant19_GTG2	6.75
Plant19_GTG3	10.13
Plant10_CT3A	20.26
Plant10_CT3B	39.88
Plant17_DS_1	7.76
Plant17_DS_2	19.5
Plant17_DS_3	14.51
Plant10_6C2S	194.87
Plant3_FL4	77.72
Plant3_FL5	74.71
Plant11_MT3	44.12

For additional information on MarSi, please contact
Global Energy Market Solutions (GEMS), Inc.
10 West 35th Street 10E9
Chicago, IL 60616
ms@gemsenergy.com