FISCAL YEAR 2021

ILLINOIS POWER AGENCY

ANNUAL REPORT

FEBRUARY 15, 2022

Illinois Power Agency
Annual Report
Fiscal Year 2021
(July 2020 - June 2021)
Prepared in Accordance with 20 ILCS 3855/1-125 and 220 ILCS 5/16-115D(d)(4)

February 15, 2022

INTRODUCTION

The Illinois Power Agency ("IPA") was established to serve the people of Illinois by administering electricity and renewable resources planning and procurement processes for Ameren Illinois Company ("Ameren Illinois"), Commonwealth Edison Company ("ComEd"), and MidAmerican Energy Company ("MidAmerican").

The IPA's processes and mandates are described in the Illinois Power Agency Act (20 ILCS 3855) and the Illinois Public Utilities Act (220 ILCS 5). The Agency strives to employ best practices to meet the goals set out for it in those statutes. Chief among these is to develop electricity and renewable resources procurement plans and processes 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. The Agency prepares electricity procurement plans on an annual basis. For renewable energy resources, the Agency develops Long-Term Renewable Resources Procurement Plans on a biennial basis.

As an independent agency subject to the oversight of the Executive Ethics Commission, the Illinois Power Agency is committed to:

- Conducting competitive procurement processes to procure the supply resources identified in procurement plans.
- Ensuring that the process of power procurement is conducted in an ethical and transparent fashion, immune from improper influence.
- Operating in a structurally insulated, independent and transparent fashion so that nothing impedes its mission to secure power at the best prices the market will bear, provided that it meets all applicable legal requirements.
- Continuing to review its policies and practices to determine how best to meet its mission of providing the lowest cost power to the greatest number of people, at any given point in time, in accordance with applicable law.

Fiscal Year 2021 featured the following accomplishments for the Agency:

- The Agency developed its 2021 Annual Electricity Procurement Plan and had that Plan approved by the Illinois Commerce Commission ("Commission") for implementation in calendar year 2021. The Plan governs the procurement of energy for Ameren Illinois, ComEd, and MidAmerican, and capacity for Ameren Illinois. The procurements are for eligible retail customers, who are those residential and small commercial customers who have not switched to an alternative retail electric supplier.
    - The Agency successfully conducted electricity and capacity procurement events as approved in the 2020 and 2021 Annual Procurement Plans.
- Renewable Resources Procurement and Program activities:
    - The Adjustable Block Program – a solar incentive program administered by the IPA to incent the development of new photovoltaic distributed generation and community solar projects pursuant to Section 1-75(c)(1)(K)-(M) of the IPA Act – which had begun accepting project applications in Fiscal Year 2019 reached capacity for small distributed generation projects in late 2020 (after having reached capacity for large distributed generation projects in the spring of 2020) and project applications were put on to waitlists pending legislative action to allow for new blocks of program capacity to open (which occurred in September of 2021 as discussed below). As of the end of Fiscal Year 2021, 3,337 distributed generation projects were on waitlists.

      25,939 projects were approved by the Commission by the end of Fiscal Year 2021, and at the time of the publishing of this Annual Report, 24,858 of those projects had been energized (including 60 of the 111 community solar projects). Assuming all remaining projects from this first phase of the program are successfully completed, the result will be the development of over 679 MW of photovoltaic distributed generation and community solar projects in Illinois. Additional information on the Adjustable Block Program can be found at: www.illinoisabp.com.
    - The Illinois Solar for All Program – a program to support the development of solar projects for low-income households and communities program pursuant to Section 1-56(b) of the IPA Act –opened its third program year in June of 2020. Three Low-income Community Solar projects (totaling 4.5 MW), 18 Non-Profit/Public Facilities projects (totaling 2.7 MW in capacity), and 62 Low-Income Distributed Generation projects (totaling 709 kW) were approved during the program year. Additional information on the Illinois Solar for All Program can be found at: www.illinoissfa.com.

- The Agency held a procurement to support the development of new utility-scale wind projects in March 2021 and no bids were selected.
- In June of 2021 the Agency began the process of updating the Long-Term Renewable Resources Procurement Plan with a series of stakeholder workshops. The Agency subsequently released a draft Plan for public comment in August 2021 and then withdrew that Plan in September 2021 due the enactment of Public Act 102-0662.

Many of the challenges faced by the Agency with its implementation of the Renewable Portfolio Standard in Fiscal Year 2021 were addressed through the enactment of Public Act 102-0662 (colloquially known as the Climate and Equitable Jobs Act, or CEJA) on September 15, 2021. This Act contains significant changes to the Renewable Portfolio Standard including:

- Revised goals
- Increased funding
- Changes to competitive procurements for utility-scale renewables
- Changes to the Adjustable Block Program and the Illinois Solar for All Program
- A new focus on labor standards and equity across the renewable energy industry
- New reporting requirements for the Agency's Annual Report.

The Agency's Fiscal Year 2022 Annual Report will reflect these many changes.

The IPA welcomes your questions and hopes you will take advantage of the information offered herein, on the IPA's program websites linked above, and on the Agency's website: www.illinois.gov/IPA.

REPORT ORGANIZATION

20 ILCS 3855/1-125 requires that, by February 15 of each year, the Agency shall report annually to the Governor and the General Assembly on the operations and transactions of the Agency. The annual report shall include, but not be limited to, each of the following:

(1) The average quantity, price, and term of all contracts for electricity procured under the procurement plans for electric utilities.

(2) (Blank)[1]

(3) The quantity, price, and rate impact of all energy efficiency and demand response measures purchased for electric utilities, and any measures included in the procurement plan pursuant to Section 16-111.5B of the Public Utilities Act.

(4) The amount of power and energy produced by each Agency facility.

(5) The quantity of electricity supplied by each Agency facility to municipal electric systems, governmental aggregators, or rural electric cooperatives in Illinois.

(6) The revenues as allocated by the Agency to each facility.

(7) The costs as allocated by the Agency to each facility.

(8) The accumulated depreciation for each facility.

(9) The status of any projects under development.

(10) Basic financial and operating information specifically detailed for the reporting year and including, but not limited to, income and expense statements, balance sheets, and changes in financial position, all in accordance with generally accepted accounting principles, debt structure, and a summary of funds on a cash basis.

(11) The average quantity, price, contract type and term and rate impact of all renewable resources purchased under the electricity procurement plans for electric utilities.

(12) A comparison of the costs associated with the Agency's procurement of renewable energy resources to (A) the Agency's costs associated with electricity generated by other types of generation facilities and (B) the benefits associated with the Agency's procurement of renewable energy resources.

(13) 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

[1] Previous Illinois Power Agency Annual Reports included a Section (2) that provided information on, "The quantity, price, and rate impact of all renewable resources purchased under the electricity procurement plans for electric utilities." That provision was repealed pursuant to Public Act 099-0536 through consolidating the Agency's Annual Report and its previously-required separate report on the Cost and Benefits of Renewable Resource Procurement. Information comparable to what was previously reported in Section (2) can be found in Section (11) of this Report.

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.

(14) An analysis of 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.

In addition to these requirements, Section 16-115D(d)(4) of the Public Utilities Act requires that, beginning April 1, 2012 and by April 1 of each year thereafter, the Agency shall submit the following information to the General Assembly, the Commission, and alternative retail electric suppliers:

A report of the alternative compliance payment mechanism fund 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.

This Annual Report for Fiscal Year 2021 addresses each of the above requirements, including reporting alternative compliance payment and expenditure information.[2]

[2] This Fiscal Year 2021 Annual Report reflects the reporting requirements in place during Fiscal Year 2021, during which the Agency was able to collect and maintain information reflecting the reporting requirements known at that time. Public Act 102-0662 took effect on September 15, 2021 and included modifications to the Agency's annual reporting requirements; the Agency's Fiscal Year 2022 Annual Report will include new and changed reporting requirements contained in Section 1-125 of the Illinois Power Agency Act.

(1) The average quantity, price, and term of all contracts for electricity procured under the procurement plans for electric utilities.

The IPA's 2021 Annual Procurement Plan, approved by the Illinois Commerce Commission in Docket No. 20-0717, contains a hedging strategy for the procurement of electricity under which 100% of projected eligible retail customer load is to be under contract for the upcoming (or "prompt") delivery year (starting June 1, 2021),[3,4] 50% for the following year (starting June 1, 2022), and 25% for the next year (starting June 1, 2023). This approach constitutes a continuation of the approach adopted in the 2015 through 2020 Procurement Plans, under which the Agency holds two energy procurement events per year. Each procurement uses an updated load forecast provided by the utilities to match procured volumes with actual demand more accurately. The Procurement Plan covers a calendar year of Agency activities, while energy deliveries are based on an industry-standard energy delivery year that starts June 1 (and thus is one month different from the State Fiscal Year). In Fiscal Year 2021, the IPA held two energy procurements: the first occurred in September 2020 pursuant to the 2020 Plan; the second took place in April 2021 pursuant to the 2021 Plan.

The following tables report on the names of winning suppliers, quantity, price, and term for electricity contracts procured through the two procurement events.[5] The specific months and quantities procured reflect the load forecasts provided by Ameren Illinois, ComEd and MidAmerican.

[3] Delivery year is synonymous with planning year and used interchangeably in this Report.

[4] This percentage total is 106% for July and August 2021, on-peak.

[5] Under Section 16-111.5(h) of the Public Utilities Act, "the names of the successful bidders and the load weighted average of the winning bid prices for each contract type and for each contract term shall be made available to the public." This information is included in the tables that follow. However, as the IPA "shall maintain the confidentiality of all other supplier and bidding information," individual supplier contract quantities, prices, and terms may not be disclosed and have not been included in this report or in prior annual reports.

September 2020 Procurement[6]

Ameren Illinois

Winning Suppliers

AEP Energy Partners, Inc.
Dynegy Marketing and Trade, LLC
Exelon Generation Company, LLC
Macquarie Energy LLC
NextEra Energy Marketing, LLC
Shell Energy North America (US), L.P.
The Energy Authority, Inc.
TransAlta Energy Marketing (U.S.) Inc.
Union Electric Company d/b/a Ameren Missouri

Average Prices ($/MWh) and MWs of Electricity Contracts

	On-Peak		Off-Peak	
Month(s)	Average Price	Quantity	Average Price	Quantity
October 2020	28.93	250.00	20.81	200.00
November 2020	30.08	175.00	22.36	175.00
December 2020	31.02	225.00	23.98	225.00
January 2021	37.80	325.00	28.39	250.00
February 2021	35.70	275.00	26.29	250.00
March 2021	32.44	225.00	25.15	225.00
April 2021	31.63	175.00	23.57	175.00
May 2021	31.39	175.00	22.03	150.00
June 2021	31.11	125.00	21.19	75.00
July 2021	35.84	150.00	23.66	100.00
August 2021	35.36	175.00	23.04	75.00
September 2021	32.96	150.00	23.03	100.00
October 2021	30.55	125.00	23.48	100.00
November 2021	30.33	100.00	22.95	75.00
December 2021	31.44	125.00	24.63	100.00
January 2022	36.30	175.00	27.80	125.00
February 2022	35.31	125.00	27.00	125.00
March 2022	30.61	125.00	24.70	100.00
April 2022	30.06	100.00	23.50	100.00
May 2022	29.01	75.00	21.95	50.00
June 2022	29.18	100.00	22.47	50.00

[6] Source: https://www2.illinois.gov/sites/ipa/Pages/Current_Approved_Plan.aspx

	On-Peak		Off-Peak	
Month(s)	Average Price	Quantity	Average Price	Quantity
July 2022	34.46	125.00	23.88	75.00
August 2022	33.33	125.00	23.18	50.00
September 2022	31.09	100.00	22.10	75.00
October 2022	29.03	75.00	23.34	50.00
November 2022	29.18	50.00	23.34	50.00
December 2022	29.54	75.00	23.66	75.00
January 2023	36.33	75.00	26.84	75.00
February 2023	35.46	100.00	25.99	75.00
March 2023	30.47	50.00	24.52	50.00
April 2023	30.03	25.00	23.73	25.00
May 2023	28.62	50.00	23.73	25.00

In the September 2020 procurements, the IPA also procured capacity for a portion of the eligible retail customer load of Ameren Illinois as specified in the 2020 Procurement Plan. Although the capacity procured did not include an electricity component, this information is provided below for the benefit of completeness. The following tables report on the name of winning suppliers, quantity of capacity procured in Zonal Resource Credits (ZRCs), the average contracted price, and term.

Winning Suppliers

Exelon Generation Company, LLC
Prairie Power, Inc.
Union Electric Company d/b/a Ameren Missouri
Voltus, Inc.
Wabash Valley Power Association, Inc.

Term, Average Price ($/MW-Day) and Quantities (in ZRCs) of Capacity Contracts

Term	# ZRCs Awarded	Zonal Resource Credits
Delivery Year		Average Price ($/MW-Day)
June 2020 – May 2021	293	$19.99
June 2021 – May 2022	252	$26.90

ComEd

Winning Suppliers

AEP Energy Partners, Inc.
Axpo U.S. LLC
Dynegy Marketing and Trade, LLC
Exelon Generation Company, LLC
Macquarie Energy LLC
Midwest Generation, LLC
Morgan Stanley Capital Group Inc.
NextEra Energy Marketing, LLC
Shell Energy North America (US), L.P.
TransAlta Energy Marketing (U.S.) Inc.

Average Prices ($/MWh) and MWs of Electricity Contracts

	On-Peak		Off-Peak	
Month(s)	**Average Price**	**Quantity**	**Average Price**	**Quantity**
October 2020	26.26	650.00	18.43	575.00
November 2020	27.11	700.00	19.51	625.00
December 2020	29.51	825.00	21.91	750.00
January 2021	35.95	800.00	26.24	750.00
February 2021	35.66	750.00	26.15	700.00
March 2021	29.50	675.00	22.45	625.00
April 2021	28.90	600.00	21.42	550.00
May 2021	28.43	625.00	18.85	550.00
June 2021	29.09	450.00	19.08	350.00
July 2021	31.27	525.00	20.82	425.00
August 2021	31.04	500.00	20.76	400.00
September 2021	29.96	375.00	19.85	325.00
October 2021	29.64	325.00	20.77	275.00
November 2021	29.62	350.00	20.76	325.00
December 2021	29.68	400.00	21.06	375.00
January 2022	31.83	400.00	24.39	375.00
February 2022	31.83	400.00	24.17	350.00
March 2022	29.38	325.00	21.16	325.00
April 2022	28.61	300.00	20.77	275.00
May 2022	28.77	300.00	19.65	300.00
June 2022	26.51	375.00	18.01	275.00
July 2022	30.62	475.00	20.70	375.00
August 2022	30.18	450.00	20.56	325.00
September 2022	28.06	325.00	18.04	250.00

	On-Peak		Off-Peak	
Month(s)	Average Price	Quantity	Average Price	Quantity
October 2022	26.31	225.00	19.28	175.00
November 2022	26.40	250.00	19.42	200.00
December 2022	26.70	300.00	20.51	300.00
January 2023	33.29	300.00	25.82	275.00
February 2023	33.29	300.00	25.69	250.00
March 2023	27.63	250.00	22.90	200.00
April 2023	26.38	175.00	20.39	175.00
May 2023	26.06	225.00	18.56	200.00

MidAmerican

No Procurement

April 2021 Procurement[7]

Ameren Illinois

Winning Suppliers

AEP Energy Partners, Inc.
Exelon Generation Company, LLC
Macquarie Energy LLC
NextEra Energy Marketing, LLC
Shell Energy North America (US), L.P.
TransAlta Energy Marketing (U.S.) Inc.
Union Electric Company d/b/a Ameren Missouri

Average Prices ($/MWh) and Quantities (MW) of Electricity Contracts

	On-Peak		Off-Peak	
Month(s)	Average Price	Quantity	Average Price	Quantity
June 2021	29.89	525.00	21.91	350.00
July 2021	35.73	650.00	24.57	425.00
August 2021	34.73	625.00	23.91	400.00
September 2021	32.14	475.00	22.33	350.00
October 2021	30.69	175.00	21.97	150.00
November 2021	30.36	200.00	22.90	175.00
December 2021	30.85	225.00	23.94	200.00
January 2022	38.61	250.00	28.89	200.00
February 2022	37.61	250.00	28.35	200.00
March 2022	30.80	200.00	23.87	175.00
April 2022	30.46	150.00	22.46	150.00
May 2022	29.94	200.00	22.36	150.00
June 2022	29.65	125.00	22.21	75.00
July 2022	35.54	150.00	23.51	100.00
August 2022	34.86	150.00	23.08	100.00
September 2022	31.21	100.00	22.15	75.00
October 2022	28.65	75.00	22.43	75.00
November 2022	29.39	100.00	22.59	75.00
December 2022	31.24	100.00	23.52	100.00
January 2023	36.79	125.00	27.00	100.00
February 2023	36.04	100.00	27.00	100.00
March 2023	30.09	100.00	24.23	75.00
April 2023	29.89	75.00	22.69	75.00

[7] Source: https://www2.illinois.gov/sites/ipa/Pages/Current_Approved_Plan.aspx

	On-Peak		Off-Peak	
Month(s)	**Average Price**	**Quantity**	**Average Price**	**Quantity**
May 2023	29.08	75.00	22.53	75.00
June 2023	28.84	100.00	22.53	50.00
July 2023	34.91	125.00	23.30	75.00
August 2023	34.46	125.00	23.30	75.00
September 2023	30.68	75.00	22.91	50.00
October 2023	28.17	50.00	24.03	25.00
November 2023	28.01	50.00	24.03	25.00
December 2023	29.80	75.00	23.62	75.00
January 2024	38.11	75.00	28.28	75.00
February 2024	36.53	75.00	26.96	50.00
March 2024	31.02	50.00	24.03	25.00
April 2024	30.56	25.00	24.03	25.00
May 2024	29.62	50.00	24.03	25.00

In the April 2021 procurement, the IPA also procured capacity for a portion of the eligible retail customer load of Ameren Illinois as specified in the 2021 Procurement Plan. Although the capacity procured did not include an electricity component, this information is provided below for the benefit of completeness. The following tables report on the names of winning suppliers, quantity of capacity procured - in Zonal Resource Credits (ZRCs), the average contracted price, and term.

Winning Suppliers

Hoosier Energy Rural Electric Cooperative, Inc.
Voltus, Inc.

Term, Average Price ($/MW-Day) and Quantities (in ZRCs) of Capacity Contracts[8]

Term	Zonal Resource Credits	
Delivery Year	**Average Price**	**Quantity**
June 2022 – May 2023	$29.50 per MW-day	
June 2023 – May 2024	$32.88 per MW-day	

[8] In accordance with the RFP rules and previous Commission orders, quantity information is provided where the number of successful bidders is greater than two.

ComEd

Winning Suppliers

AEP Energy Partners, Inc.
Axpo U.S. LLC
Enel Trading North America, LLC
Exelon Generation Company, LLC
Macquarie Energy LLC
Midwest Generation, LLC
Morgan Stanley Capital Group Inc.
NextEra Energy Marketing, LLC
Shell Energy North America (US), L.P.
TransAlta Energy Marketing (U.S.) Inc.

Average Prices ($/MWh) and Quantities (MW) of Electricity Contracts

	On-Peak		Off-Peak	
Month(s)	**Average Price**	**Quantity**	**Average Price**	**Quantity**
June 2021	28.28	1825.00	19.56	1500.00
July 2021	33.21	2450.00	22.44	1800.00
August 2021	32.52	2300.00	21.48	1675.00
September 2021	29.54	1550.00	19.69	1325.00
October 2021	29.27	675.00	20.81	625.00
November 2021	29.21	775.00	20.87	700.00
December 2021	29.56	925.00	21.33	825.00
January 2022	35.73	925.00	25.77	850.00
February 2022	34.56	850.00	24.88	800.00
March 2022	29.22	775.00	21.76	700.00
April 2022	28.22	650.00	20.33	600.00
May 2022	28.09	700.00	19.80	625.00
June 2022	27.83	475.00	18.56	375.00
July 2022	30.67	550.00	20.46	450.00
August 2022	30.42	525.00	19.92	425.00
September 2022	28.56	375.00	18.91	350.00
October 2022	28.65	325.00	19.17	275.00
November 2022	28.47	375.00	19.48	325.00
December 2022	28.88	425.00	20.82	375.00
January 2023	31.53	425.00	25.24	400.00
February 2023	30.36	400.00	23.55	375.00

	On-Peak		Off-Peak	
March 2023	28.22	350.00	20.74	325.00
April 2023	28.44	300.00	19.01	275.00
May 2023	28.06	325.00	18.73	300.00
June 2023	26.52	400.00	18.07	300.00
July 2023	30.97	500.00	20.19	400.00
August 2023	30.31	450.00	19.67	350.00
September 2023	27.73	300.00	18.32	250.00
October 2023	27.03	225.00	18.87	175.00
November 2023	27.13	250.00	19.56	200.00
December 2023	27.83	325.00	21.08	300.00
January 2024	32.64	325.00	25.16	275.00
February 2024	31.84	300.00	24.04	275.00
March 2024	27.63	250.00	21.03	225.00
April 2024	27.51	200.00	19.38	175.00
May 2024	26.91	250.00	19.04	175.00

MidAmerican

Winning Suppliers

TransAlta Energy Marketing (U.S.) Inc.

Average Prices ($/MWh) and Quantities (MW) of Electricity Contracts[9]

Month(s)	On-PeakAverage Price	Off-Peak Average Price
July 2021	33.54	Not procured
August 2021	33.27	Not procured

[9] In accordance with the RFP rules and previous Commission orders, quantity information is provided where the number of successful bidders is greater than two.

(2) (Blank)

(3) The quantity, price, and rate impact of all energy efficiency and demand response measures purchased for electric utilities, and any measures included in the procurement plan pursuant to Section 16-111.5B of the Public Utilities Act.

Consistent with prior years, the IPA did not directly purchase energy efficiency or demand response measures for ComEd or Ameren Illinois in Fiscal Year 2021.

Procurement Plans developed by the Agency for the years 2013 through 2017 included the approval of incremental energy efficiency programs pursuant to Section 16-111.5B of the Public Utilities Act. Those previsions were terminated as part of Public Act 99-0906, which took effect on June 1, 2017 and thus the IPA has not included energy efficiency in its procurement plans since that time.

Under current market and regulatory conditions, the IPA believes that a demand response procurement by the IPA could not meet the standards set forth in Section 16-111.5(b)(3) of the Public Utilities Act. Reasons for this include, for example, the statutory requirement that demand response under this provision must come from "eligible retail customers," and as the IPA is not aware of any simple, straightforward way of definitively determining whether a non-competitive class customers take supply from the utility or an alternative retail electric supplier for purposes of any demand response aggregation, there may simply be no feasible way to ensure that only eligible retail customers participate. As a result, the IPA has not included demand response procurements in its annual electricity procurement plan and the ICC has approved that determination.

(4) The amount of power and energy produced by each Agency facility.

Consistent with prior years, the IPA had no Agency facilities during Fiscal Year 2021.

(5) The quantity of electricity supplied by each Agency facility to municipal electric systems, governmental aggregators, or rural electric cooperatives in Illinois.

Consistent with prior years, the IPA had no Agency facilities during Fiscal Year 2021.

(6) The revenues as allocated by the Agency to each facility.

Consistent with prior years, the IPA had no Agency facilities during Fiscal Year 2021.

(7) The costs as allocated by the Agency to each facility.

Consistent with prior years, the IPA had no Agency facilities during Fiscal Year 2021.

(8) The accumulated depreciation for each facility.

Consistent with prior years, the IPA had no Agency facilities during Fiscal Year 2021.

(9) The status of any projects under development.

Consistent with prior years, the IPA had no Agency facilities under development during Fiscal Year 2021.

Among the Agency's goals and objectives enumerated in the Illinois Power Agency Act are the following:

- *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 the Agency's facilities at cost to one or more of the following: municipal electric systems, governmental aggregators, or rural electric cooperatives in Illinois.*[10]

[10] 20 ILCS 3855/1-5(C) and (D).

The Act puts a number of restrictions on the Agency that severely limit its ability to develop the allowed facilities in the current marketplace. See, for example:

> *At the Agency's discretion, it may conduct feasibility studies on the construction of any facility. Funding for a study shall be assessed to municipal electric systems, governmental aggregators, units of local government, or rural electric cooperatives requesting the feasibility study; or through an appropriation from the General Assembly.*
>
> No entities have requested such a study.
>
> *The Agency may enter into contractual arrangements with private and public entities, including but not limited to municipal electric systems, governmental aggregators, and rural electric cooperatives, to plan, site, construct, improve, rehabilitate, and operate those electric generation and co-generation facilities.*
>
> No entities have requested such arrangements.
>
> *The first facility that the Agency develops, finances, or constructs shall be a facility that uses coal produced in Illinois. The Agency may, however, also develop, finance, or construct renewable energy facilities after work on the first facility has commenced.*
>
> *Any such facility that uses coal must be a clean coal facility and must be constructed in a location where the geology is suitable for carbon sequestration.*
>
> *The Agency may supply electricity produced by the Agency's facilities to municipal electric systems, governmental aggregators, or rural electric cooperatives in Illinois. The electricity shall be supplied at cost. Electric utilities shall not be required to purchase electricity directly or indirectly from facilities developed or sponsored by the Agency.*
>
> Financing of new generation generally requires that there be certainty regarding the contractual obligation to purchase the output of the facility. Even priced at cost, electricity produced by such a facility is likely to be priced significantly above the market price of electricity for the foreseeable future. Without a mandate to purchase such electricity, buyers would not elect to purchase the significantly more expensive electricity from a clean coal facility, let alone enter into a contract featuring the length and terms necessary to finance such a facility's construction. Due to a severely restricted pool of potential buyers and the apparent absence of need among those potential buyers, the development of a new IPA facility is unlikely to be feasible for the foreseeable future.
>
> *The Agency may sell excess capacity and excess energy into the wholesale electric market at prevailing market rates; provided, however, the Agency may not sell excess capacity or*

excess energy through the procurement process described in Section 16-111.5 of the Public Utilities Act.

The Agency shall not directly sell electric power and energy to retail customers. Nothing in this paragraph shall be construed to prohibit sales to municipal electric systems, governmental aggregators, or rural electric cooperatives.
(Source: P.A. 95-481, eff. 8-28-07; 95-1027, eff. 6-1-09.)

These provisions mean that the Agency may not serve as a seller to retail load in Illinois from any facilities it develops, which serves as a protection for both customers and the market. However, a reduced pool of potential buyers helps ensure that there is not sufficient demand at this time (or in the near future) for the IPA to develop a new facility.

(10) Basic financial and operating information specifically detailed for the reporting year and including, but not limited to, income and expense statements, balance sheets, and changes in financial position, all in accordance with generally accepted accounting principles, debt structure, and a summary of funds on a cash basis.

The Agency's Fiscal Year 2021 unaudited Financial Statements and Notes are contained in the attached Appendix A. Appendix B contains a summary of funds on a cash basis.

(11) The average quantity, price, contract type and term and rate impact of all renewable resources purchased under the electricity procurement plans for electric utilities.

This section of the report, in addition to providing the average quantity, price, contract type and term of all renewable resources purchased, provides a comparison of the costs associated with the procurement of the renewable resources to the costs associated with electricity generated by other types of generation facilities. In this Report, "cost" is used to refer to a quantity procured multiplied by that quantity's average unit price.

Information on the resources procured and the results of the competitive procurements are presented in Tables, 2, 3, and 4 below for the 2020-21 delivery year for ComEd, Ameren Illinois, and MidAmerican, respectively.[11] To place the costs of renewable resources and conventional generation on a level footing, procurement costs are compared for RECs and electricity contracted or delivered to the utility's bundled rate customers during the 2020-21 delivery year. The following costs are tabulated:

- The weighted average price and cost of RECs procured by the Agency;
- The weighted average price per MWh and cost of the blocks of electricity procured by the Agency;
- For Ameren Illinois and ComEd, the 2010 Long-Term Power Purchase Agreements ("LTPPAs") purchase costs broken down to show the imputed REC and electricity prices,[12] beginning with the 2012-13 delivery year, which is the first year of delivery under those agreements;
- For Ameren Illinois, ComEd, and MidAmerican, the average price and cost of RECs procured in the 2016 Spring Distributed Generation Procurement, the 2017 Spring Distributed Generation Procurement, and the 2017 Fall Distributed Generation Procurement (Ameren Illinois and ComEd only);
- For Ameren Illinois, ComEd, and MidAmerican, the average price and cost of RECs procured in the Competitive Procurements for new Utility-Scale Wind, new Utility-Scale Solar, and Brownfield Site Solar from 2017 through 2019; and

[11] Historical information is available in the Agency's Report on Costs and Benefits of Renewable Resource Procurement published on April 1, 2016, and in the Fiscal Year 2016, Fiscal Year 2017, Fiscal Year 2018, Fiscal Year 2019, and Fiscal Year 2020 Annual Reports.

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

- For Ameren Illinois, and ComEd, the average imputed price and cost of RECs delivered under the Adjustable Block Program.

With regard to the 2010 LTPPAs, those contracts contain bundled pricing for electricity and RECs. REC prices are "imputed" by subtracting an electricity price from the bundled price. The electricity prices used in those contracts are determined through a forward energy curve calculated at the time of the procurement event. The process of imputing these REC prices is described in Appendix K to the Agency's 2010 Procurement Plan.[13]

Although the tables below compare the costs of procured RECs to the costs of procured electricity, it should be noted that these costs are not for equivalent products. RECs represent only the value of the environmental attributes of electricity produced from renewable energy facilities, and not the value of the underlying electricity. Alternatively, the costs shown for electricity procured represent prices of actual electricity procured for delivery and use by the end customer. In general, the REC costs are additive to the conventional supply costs when calculating individual customer rate and bill impacts. The Agency also notes that the costs reported herein are only for the supply of electricity and do not include distribution, transmission or other costs related to the provision of electric service.

The Competitive Procurements include the Initial Forward Procurements, Subsequent Forward Procurements, and additional Forward Procurements conducted by the Agency, from 2017 through 2019, for the utilities, as required by Section 1-75(c)(1)(G) of the IPA Act. These procurements were for 15-year contracts for RECs to be delivered annually from new utility-scale wind projects, new utility-scale solar projects and brownfield site photovoltaic projects. The REC deliveries may not start before June 1, 2019 and must start by June 1, 2022[14]. On March 18, 2021 the IPA conducted a procurement for RECs from utility-scale wind projects as a follow up to a procurement held in October 2019 which did not result in any selected bids. The March 2021 procurement also had no selected bids.

The average price and cost in Tables 2, 3, and 4 are for all the Competitive Procurements from 2017 through 2019.[15] The average price and cost are based on actual deliveries.

Sections 1-75(c)(1)(K) and (L) of the IPA Act, as amended by Public Act 99-0906, required the Agency to establish an Adjustable Block Program ("ABP") for the procurement of RECs from new photovoltaic distributed generation systems and from new photovoltaic community renewable generation projects. The procurements under the ABP are for 15-year contracts with RECs priced

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

[14] This deadline was initially set at June 1, 2021 in Public Act 99-0906 and was subsequently extended to June 1, 2022 through Public Act 101-0113 in the event of certain development delays like the establishment of an operating interconnection.

[15] ComEd, Ameren Illinois, and MidAmerican provided the information in these tables in response to the IPA's data requests issued January 4, 2022.

according to a transparent schedule of administratively-set prices. The average price and cost of ABP RECs in tables 2, 3 and 4 are based on actual deliveries.

ComEd

Table 2 shows the average quantity, price and contract type of all renewable energy resources purchased and a comparison of the cost of RECs relative to the cost of electricity under contract for delivery to ComEd during the 2020-21 delivery year.

Table 2: ComEd - Comparison of the Cost of RECs Relative to the Cost of Electricity

	RECs and Electricity Delivered in the 2020-21 Delivery Year		
Procurements of REC from Renewable Energy Resources	**Quantity [RECs]**	**Average Unit Price**	**Cost[16]**
Competitive Procurements	492,361	$3.90	$1,921,654
Adjustable Block Program	210,093	$60.93	$12,800,480
2017 Fall Five-Year Distributed Generation REC Procurement[17]	4,784	$62.20	$297,549
2017 Spring Five-Year Distributed Generation REC Procurement[18]	11,058	$128.38	$1,419,619
2016 Spring Five-Year Distributed Generation REC Procurement[19]		$129.50	
2010 Long-Term Purchase Agreements - REC Procurement[20]	1,261,725	$18.31	$23,096,220
Total RECs[21]	1,980,814	$20.01	$39,638,216
2010 Long-Term Purchase Agreements - Electricity Procurement[22]	1,261,725	$46.35	$58,477,103
Procurements of Electricity from Conventional Resources	**Quantity [MWh]**	**Average Unit Price**	**Cost**
2020 Fall Block Energy Procurement	3,903,200	$26.08	$101,797,114
2020 Spring Block Energy Procurement	8,157,600	$23.62	$192,654,588
2019 Fall Block Energy Procurement	2,962,800	$25.14	$74,489,724
2019 Spring Block Energy Procurement	2,790,800	$26.54	$74,060,860
2018 Fall Block Energy Procurement	2,190,200	$25.71	$56,316,498
2018 Spring Block Energy Procurement	2,333,625	$27.48	$64,137,167
Total Electricity from Conventional Resources	22,338,225	$25.22	$563,455,950

[16] Cost = Quantity times Average Unit Price.

[17] RECs purchased using collected ACP from hourly rate customers; thus, this purchase has no rate effect on ComEd's fixed-price rate customers.

[18] RECs purchased using collected ACP from hourly rate customers; thus, this purchase has no rate effect on ComEd's fixed-price rate customers.

[19] In accordance with the procurement RFP rules and previous Illinois Commerce Commission orders, quantity information is only released when the number of successful bidders in a procurement is greater than two. The results of the 2016 Distributed Generation Procurement did not meet that threshold, therefore quantity (and cost) is not provided. The IPA also notes that these RECs were purchased using collected ACP from hourly rate customers; thus, this purchase has no rate effect on ComEd's fixed-price rate customers.

[20] This represents the Annual Contract Quantity Commitment of RECs specified in the contract and the imputed REC price.

[21] Total REC quantities and contracted cost includes the results of the 2016 Spring procurement that is not individually disclosed.

[22] This represents the energy associated with the Annual Contract Quantity Commitment of RECs specified in the contract and the difference between the Contract Price and the Imputed REC Price.

Ameren Illinois

Table 3 shows the average quantity, price and contract type of all renewable resources purchased and a comparison of the cost of RECs relative to the cost of electricity under contract for delivery to Ameren Illinois during the 2020-2021 delivery year.

Table 3: Ameren Illinois - Comparison of the Cost of RECs Relative to the Cost of Electricity

	RECs and Electricity Delivered in the 2020-21 Delivery Year		
Procurements of REC from Renewable Energy Resources	**Quantity [RECs]**	**Average Unit Price**	**Cost[23]**
Competitive Procurements	1,749,391	$4.70	$8,220,283
Adjustable Block Program	327,566	$59.95	$19,637,582
2017 Fall Five-Year Distributed Generation REC Procurement[24]	327	$127.54	$41,706
2017 Spring Five-Year Distributed Generation REC Procurement[25]	2,511	$194.85	$489,268
2016 Spring Five-Year Distributed Generation REC Procurement[26]		$154.31	
2010 Long-Term Purchase Agreements - REC Procurement[27]	600,000	$12.92	$7,752,000
Total RECs[28]	2,680,230	$13.51	$36,207,966
2010 Long-Term Purchase Agreements - Electricity Procurement[29]	600,000	$46.18	$27,706,382
Procurements of Electricity from Conventional Resources	**Quantity [MWh]**	**Average Unit Price**	**Cost**
2020 Fall Block Energy Procurement	1,258,800	$28.47	$35,834,048
2020 Spring Block Energy Procurement	2,253,000	$25.64	$57,762,242
2019 Fall Block Energy Procurement	712,200	$27.20	$19,372,144
2019 Spring Block Energy Procurement	817,600	$28.15	$23,011,368
2018 Fall Block Energy Procurement	514,000	$28.51	$14,654,578
2018 Spring Block Energy Procurement	553,600	$28.32	$15,680,642
Total Electricity from Conventional Resources	6,109,200	$27.22	$166,315,022

[23] Cost = Quantity times Average Unit Price

[24] RECs were purchased using collected ACP from hourly rate customers; thus, this purchase has no rate effect on Ameren Illinois' fixed-price rate customers.

[25] RECs were purchased using collected ACP from hourly rate customers; thus, this purchase has no rate effect on Ameren Illinois' fixed-price rate customers.

[26] In accordance with the procurement RFP rules and previous Illinois Commerce Commission orders, quantity information is only released when the number of successful bidders in a procurement is greater than two. The results of the 2016 Distributed Generation Procurement did not meet that threshold, therefore quantity (and cost) is not provided. The IPA also notes that these RECs were purchased using collected ACP from hourly rate customers; thus, this purchase has no rate effect on Ameren Illinois' fixed-price rate customers.

[27] This represents the Annual Contract Quantity Commitment of RECs specified in the contract and the imputed REC price.

[28] Total REC quantities and contracted cost includes the results of 2016 Spring procurement that is not individually disclosed.

[29] This represents the energy associated with the Annual Contract Quantity Commitment of RECs specified in the contract and the difference between the Contract Price and the Imputed REC Price.

MidAmerican

Table 4 shows the price and contract type of all renewable resources purchased and a comparison of the cost of RECs relative to the cost of electricity under contract for delivery to MidAmerican during the 2020-2021 delivery year.

Table 4: MidAmerican - Comparison of the Cost of RECs Relative to the Cost of Electricity

	RECs and Electricity Delivered in the 2020-21 Delivery Year		
Procurements of REC from Renewable Energy Resources	**Quantity [RECs]**	**Average Unit Price**	**Cost[30]**
Competitive Procurements	2,941	$3.69	$10,848
Adjustable Block Program	288	$46.48	$13,374
2017 Spring Five-Year Distributed Generation REC Procurement	445	$162.91	$72,493
2016 Spring Five-Year Distributed Generation REC Procurement[31]		$189.90	
Total RECs[32]	3,776	$30.75	$116,085
Procurements of Electricity from Conventional Resources	**Quantity [MWh]**	**Average Unit Price**	**Cost**
2020 Spring Block Energy Procurement	44,400	$27.81	$1,234,800
Total Electricity from Conventional Resources	44,400	$27.81	$1,234,800

[30] Cost = Quantity times Average Unit Price

[31] In accordance with the procurement RFP rules and previous Illinois Commerce Commission orders, quantity information is only released when the number of successful bidders in a procurement is greater than two. The results of the 2016 Distributed Generation Procurement did not meet that threshold, therefore quantity (and cost) is not provided.

[32] Total REC quantities and contracted cost includes the results of the 2016 Spring procurement that is not individually disclosed.

Term of REC Contracts for all Utilities

The IPA's procurement of renewable energy resources includes REC procurements of various terms (i.e., length of contract). Table 5 shows the term[33] associated with each procurement of renewable resources for delivery to Ameren Illinois, ComEd and MidAmerican during the 2020-21 delivery year.

Table 5: Term of RECs Contracts for Delivery during the 2020-21 Delivery Year

Procurements from Renewable Energy Resources	Ameren Illinois & ComEd Delivery Terms	MidAmerican Delivery Terms
Competitive Procurement RECs under Contract	15 years starting June 2019	15 years starting June 2019
Adjustable Block Program RECs under Contract	15 years starting June 2019	-
2017 Fall Five-Year Distributed Generation REC Procurement	5 years starting June 2017	-
2017 Spring Five-Year Distributed Generation REC Procurement	5 years starting June 2017	5 years starting June 2017
2016 Spring Five-Year Distributed Generation REC Procurement	5 years starting June 2016	5 years starting June 2016
2010 Long-Term Purchase Agreements REC Procurement	20 years starting June 2012	-

[33] The term indicated in this section is merely the nominal term for REC deliveries upon a system becoming energized or beginning with its first REC deliveries; the full term applicable to obligations under REC delivery contracts may varies depending on the contracted system's specific development schedule (i.e., contractual obligations may still need to be fulfilled before deliveries commence, and achieving those milestones may occur months or even years later than the month/year specified in Table 5).

(12) A comparison of the costs associated with the Agency's procurement of renewable energy resources to (A) the Agency's costs associated with electricity generated by other types of generation facilities and (B) the benefits associated with the Agency's procurement of renewable energy resources.[34]

The costs associated with the Agency's procurement of renewable energy resources and the Agency's costs of electricity generated by other types of generation facilities are presented above under (11). The environmental and economic benefits that result from the generation of renewable energy are considered in both quantitative and qualitative terms in this section. The primary benefits associated with renewable energy resources are attributable to the reduction of the pollutants emitted by fossil fuel electricity generation that is displaced by electricity generation from renewable resources, and from the economic benefits provided by the construction and operation of these facilities. The monetary estimates of the environmental benefits are focused on the reduced costs that result from the avoidance of emissions-related adverse health effects and crop damages. The economic benefits include increased employment that results from the construction and operation of renewable resource facilities, increased taxes or payments in lieu of taxes, and the local revenue and supply chain impacts that benefit local businesses which supply products and services to these facilities and their workers.

1. Environmental Benefits

The environmental benefits associated with renewable energy generation primarily involve the benefits of avoiding the pollutants emitted by electricity generated by the combustion of fossil fuels. Emissions from the combustion of fossil fuels—specifically, particulate matter (PM),[35] sulfur dioxide (SO_2) and nitrogen oxides (NO_x)—have been linked to a wide range of adverse health effects. The adverse health impacts that can result from PM emissions are related, to a large extent, to the size of the particles such that the smaller the particle, the greater the potential for damaging health effects. Fine particles referred to as $PM_{2.5}$ are the most damaging and are associated with respiratory diseases such as asthma, bronchitis, and emphysema as well as cardio-pulmonary disease and cancer.[36] PM emissions can also damage the surfaces of agricultural crops adversely affecting growth rates and yields. The health effects associated with SO_2 emissions include irritation and inflammation of tissue exposed to the pollutant, which can exacerbate respiratory diseases. NO_x emissions can have adverse impacts such as respiratory and eye irritation and reduced crop yield. SO_2 and NO_x emissions also add to $PM_{2.5}$ emissions in the form of

[34] 20 ILCS 3855/1-125(12).

[35] PM emissions are generally reported as either PM_{10}, particulates that have diameters of 10 micrometers or less, or $PM_{2.5}$, particulates of 2.5 micrometers or less.

[36] State of Illinois, Illinois Environmental Protection Agency, Illinois Air Quality Report AQI Air Quality Index, 2020.

secondary sources as some of these emissions turn into nitrate and sulfate particles in the atmosphere after being emitted. NO_x emissions are also a precursor to the photochemical formation of ozone (O_3). Elevated levels of O_3 in the atmosphere can result in significant damage to vegetation as well as lung damage and exacerbation of respiratory diseases. In addition to the pollutants that have direct impacts on public health, carbon dioxide (CO_2), emitted by the combustion of fossil fuels, contributes to climate change and indirectly to increased public health concerns such as reduced agricultural production, increased waterborne and pest-related diseases, increased storm severity, and ocean acidification.[37]

In Illinois, the majority of the emissions associated with electricity generation are sourced from coal and natural gas fired power plants. In 2020, these two generation sources accounted for more than 99% of the CO_2, SO_2 and $PM_{2.5}$ as well as 87% of the NO_x emissions for electricity generation. The U.S. Energy Information Administration reported SO_2, NO_x and CO_2 emissions from power generation in the state for 2020.[38] The emissions of $PM_{2.5}$ were estimated based on the data from the U.S. EPA National Emissions Inventory and data from the Illinois EPA Air Quality Report. These emissions are shown in the following table.

Illinois Power Generation Emissions 2020 (Tons)

SO_2	62,043
NO_x	27,741
$PM_{2.5}$	2,714
CO_2	52,382,011

In the prior Annual Report, the Agency determined the composite emission factors for the coal and natural gas generation in the state based on the generation and emissions data compiled by the U.S. EIA. In this report emission factors for the emissions avoided by renewable energy generation were based on the results of the AVERT model run by the U.S. EPA in October 2021.[39] The Avoided Emissions and Generation Tool (AVERT)[40] is used to evaluate the change in pollutants

[37] U.S. Environmental Protection Agency, Air Pollution: Current and Future Challenges, www.epa.gov/clean-air-act-overview/air-pollution-current-and-future-challenges, updated September 17, 2019, accessed January 26, 2021.

[38] U.S. Energy Information Administration, Electricity, Detailed State Data-Final Annual Data for 2020, released November 3, 2021, accessed January 10, 2021, www.eia.gov/electricity/data/state.

[39] AVERT v 3.1 Avoided Emission Rates 2017-2020 (October 2021).

[40] http://epa.gov/avert/avoided-emission-rates-generated-avert.

($PM_{2.5}$, CO_2, NO_x, SO_2) emitted from electric power generation that results from energy efficiency or generation from renewable resource technologies. The AVERT model calculates the emissions impacts in terms of avoided emissions that result from renewable energy generation on a regional basis. Avoided emission rates were calculated using the AVERT model for the Midwest and Mid-Atlantic regions which are equivalent to MISO and PJM, respectively. These emission rates were multiplied by the renewable resource generation related to the Agency's procurements and then multiplied by the estimated environmental impacts (also known as "damages") for each pollutant to provide the monetary benefits associated with the renewable energy represented by the number of RECs delivered each year. This approach, using the AVERT model, provides more quantitatively robust estimates of the actual emissions that are avoided by the Agency's renewable energy procurements. For 2020, the generation emission factors for wind and utility-scale PV are: 1.28 lbs./MWh for SO_2, 1.01 lbs./MWh for NO_x, 0.095 lbs./MWh for $PM_{2.5}$ and 1,618 lbs./MWh for CO_2. For the ABP program the Agency utilized the emission factors calculated by AVERT for distributed PV, 1.30 lbs/MWh for SO_2, 1.05 lbs/MWh for NO_x, 0.105 lbs/MWh for $PM_{2.5}$, and 1,717 lbs/MWh for CO_2. These emission factors reflect the proportion of RECs delivered in MISO and in PJM in determining the final emission rate for each pollutant to be applied to the benefit calculation.

While the emissions that are displaced by renewable generation can be determined with reasonable specificity, assigning monetary values to these emissions benefits is subject to significant uncertainty. Considering this uncertainty, in this report emissions quantities and emissions factors are reported as specific data points and the monetary benefits of the reduced emissions that result from wind and solar generation are reported as ranges.

Several recent studies[41,42,43] developed estimates of the marginal damages that result from emissions from electricity generation. The following ranges of damages in dollars per ton emitted are based on the monetary values reported in these studies converted to 2020 dollars: \$7,132 to \$28,343 for SO_2, \$1,965 to \$15,053 for NO_x, and \$11,670 to \$108,877 for $PM_{2.5}$. The differences in damage estimates between studies highlight the considerable uncertainties associated with these estimates which are dependent on a range of assumptions and inputs that vary between studies. As a result, the estimates provided below should be understood to be extrapolations and estimates rather than definitive calculations of benefits by the Agency.

[41] Jaramillo, P. and Muller, N., "Air pollution emissions and damages from energy production in the U.S.: 2002-2011, Energy Policy 90 (2016) pp.202-211.

[42] Goodkind, A.L. et al, "Fine-scale damage estimates of particulate matter air pollution reveal opportunities for location-specific mitigation of emissions," PNAS, April 30, 2019, vol. 116, no. 18, 8775-8780, www.pnas.org/cgi/doi/10.1073/pnas.1816102116.

[43] National Research Council, "Hidden Costs of Energy Unpriced Consequences of Energy Production and Use," The National Academies Press, 2010.

To estimate the benefits of avoided damages from CO_2 emissions displaced, the Agency used a social cost of carbon measured in terms of dollars per ton of CO_2. The social cost of carbon is an estimate of the economic damages that would result from the emissions of an additional ton of carbon. The social cost of carbon converts the future damages estimated from the emitted carbon into present values based on a discount rate. Also considered in this estimate is the geographic area assumed to be impacted by the emissions, either in terms of global damages or domestic damages specific to the United States. The range of CO_2 emissions benefits were calculated based on the domestic social cost of carbon (in 2020 dollars) of $14/ton determined using a 5% discount rate and the social cost of carbon of $51/ton determined using a 3% discount rate.[44, 45]

Based on RECs procured by the Agency and delivered to the utilities in the 2020-2021 delivery year, it was estimated that the associated renewable resources generated a total of 2,782,447 MWh, with 2,244,693 MWh from competitive wind and utility PV procurements and 537,754 MWh from the ABP (see Tables 2-4 in Section 11 above). These MWh represent about 17% of the renewable resources generation in Illinois, which was 16,304,885 MWh in 2020.[46] Using the AVERT model emissions factors, the amount of renewable generation that is equivalent to the quantity of RECs procured by the Agency and delivered to the utilities in the 2020-2021 delivery year, and the dollar per ton estimated emissions damages, the value of the environmental benefits from these renewable resources were estimated as shown in the following table.

Estimated Benefits of Renewable Resources Procured by the Agency and Delivered to the Utilities in the 2020-21 Delivery Year

SO_2	$12.7 - $50.6 million
NO_x	$2.8 - $21.3 million
$PM_{2.5}$	$1.5 - $14.7 million
CO_2	$31.9 - $116.1 million
Total	$48.9 - $202.7 million

[44] Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, February 2021, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide, Interim Estimates under Executive Order 13990.

[45] For context the $16.50/MWH Social Cost of Carbon used for the development of the Zero Emission Standard Procurement Plan translates to $31.37/ton based on a CO_2 emissions factor of 1,052 lbs./MWh.

[46] U.S. EIA, Detailed State Data Final Annual Data for 2020, Re-released November 3, 2021.

By way of comparison, the U.S. EPA's assessment of the 2017 public health benefits associated with the reduction of emissions by wind and solar generation in the Upper Midwest ranged from $28.90/MWh to $65.30/MWh for solar generation and from $32.00/MWh to $72.30/MWh for wind generation.[47] The EPA's public health benefits were based on reduced $PM_{2.5}$, SO_2 and NO_x emissions from generation displaced by the renewable generation but did not include the benefits associated with reduced CO_2 emissions. The total estimated environmental benefits of the IPA's renewable resource procurements for the 2020-21 delivery year range from $17.57/MWh to $72.85/MWh.

A study by Lawrence Berkley National Laboratory (LBNL) and National Renewable Energy Laboratory (NREL) focused on the prospective impacts of renewable portfolio standards ("RPS") over the period of 2015 to 2050. The study assumed that state RPS policies which were in effect as of July 2016 remained the same through the end of the 35-year forecast period. The study predicts that compliance with the existing RPS goals through 2050 would reduce cumulative SO_2 emissions by 2.1 million metric tons, cumulative NO_x emissions by 2.5 million metric tons, and cumulative $PM_{2.5}$ emissions by 0.3 million metric tons.[48] If these reductions were to come to fruition, the report analysis estimates that there would be 12,000 to 28,000 fewer premature deaths due to respiratory issues over this period.[49] Based on the emissions reductions under the existing RPS, the study estimated total health and environmental benefits to be on the order of $97 billion for the U.S. over the forecast period.[50]

Based on the range of emissions benefits utilized above and the actual delivery quantity of 537,754 ABP RECs for 2020-21, the ABP emissions benefits for 2020-21 range from a low of $9.8 million to a high of $40.7 million.

2. Economic Benefits

The increasing integration of renewable energy into the electric grid is being driven in large part by state RPS requirements with the primary goal of reducing the adverse health and environmental impacts associated with electricity generation. Along with these environmental benefits, renewable generation also offers a range of economic benefits. The economic benefits that can be attributed to renewable energy include potential electricity price reductions, increased electric system reliability through portfolio diversity, as well as state and regional economic development,

[47] U.S. Environmental Protection Agency, "Public Health Benefits per kWh of Energy Efficiency and Renewable Energy in the United States: A Technical Report," July 2019.

[48] Mai, T., Wiser, R., Barbose, G., Bird, L., Heeter, J., Keyser, D., Krishnan, V., Macknick, J., and Millstein, D., "A Prospective Analysis of the Costs, Benefits, and Impacts of U.S. Renewable Portfolio Standards," National Renewable Energy Laboratory, Lawrence Berkeley National Laboratory, December 2016, NREL/TP-6A20-67455.

[49] Id.

[50] Id. at 45.

including employment and tax revenue benefits. Additional benefits that can be obtained from solar PV distributed generation programs, such as the Solar for All Program, include: providing incentives for the development of renewable resources in under-served, low income neighborhoods; addressing some of the environmental justice issues affecting these neighborhoods; increased job training and employment in high unemployment areas; and improving local distribution system reliability.[51]

a) Electricity Price Benefits

Price Moderation and Portfolio Diversity

Wind and solar power offer opportunities for lower wholesale electricity costs, generation supply portfolio diversity and, because these sources do not involve fuel costs, the costs of wind and solar generation are not affected by fuel price volatility. In addition to moderating fuel induced price volatility, wind and solar can provide diversity benefits to a generation portfolio that contains significant amounts of fossil fuel and nuclear generation. These renewable resources offer improved reliability by potentially substituting for other resources that may be adversely impacted by fuel supply and transportation issues, supply disruptions, and the potential delay or avoidance of conventional generation capital expenditures.[52] Wind and solar in a diversified portfolio can provide a hedge against the cost impacts associated with potential changes in environmental regulations that could adversely affect the costs of, and ultimately the price of electricity, from fossil fuel and nuclear generation.[53] Wind, solar, and certain other forms of renewable energy are not subject to the uncertainty surrounding potential future carbon taxes, unlike fossil fuel-fired power plants.[54]

Since most of the costs associated with wind and solar generation involve upfront investments, these resources have low operating costs. The resulting low marginal costs do not involve fuel costs and as a result can reduce the wholesale price of electricity by shifting more expensive (on a marginal cost basis) resources out on the supply curve. However, the net pricing benefits attributable to renewable energy resources are difficult to monetize and involve determinations

[51] U.S. Department of Energy, ICF, Inc. "Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar," May 2018.

[52] U.S. Environmental Protection Agency, "Quantifying the Multiple Benefits of Energy Efficiency and Renewable Energy: A Guide for State and Local Governments. Part One: The Multiple Benefits of Energy Efficiency and Renewable Energy." 2018 edition.

[53] *Guide to Purchasing Green Power*, United States Department of Energy Office of Renewable Energy and Energy Efficiency, at 5. (March 2010; Update: September 2018). www.epa.gov/greenpower/guide-purchasing-green-power.

[54] Loomis, D., Stroup, I., Center for Renewable Energy, Illinois State University, "Economic Impact: Illinois Wind Energy Development," June 2016, at 10.

that will be impacted by the trade-off between the system costs[55] incurred by higher market penetration and the downward pressure exerted on wholesale electricity prices by higher levels of renewable resource generation.

Impacts on Locational Marginal Prices

Wholesale electric energy prices are set for hourly periods based on bidding by available generators into the regional markets. Most analyses of the impact of renewable generation on electricity prices address these Locational Marginal Prices ("LMPs") and assume generator bids reflect variable costs. LMPs consist of three components – Energy, Congestion, and Marginal Losses. The energy component prices energy purchases and sales, the congestion component prices transmission congestion costs to move energy from one point to another, and the marginal losses component prices losses on the bulk power system as a result of moving power from one point to another. An impact on any one of these components will have a corresponding impact on the overall LMP. Renewable generation resources tend to lower the price of electricity in the real-time markets (LMPs) and indirectly lower forward wholesale market prices.[56]

The Lawrence Berkley National Laboratory conducted a study to assess the impact on wholesale electricity prices that resulted from growing variable renewable energy generation (wind and solar) over the period of 2008 through 2017.[57] This study also evaluated the relative impacts that other market drivers, notably lower natural gas prices and increasing gas-fired generation, had on wholesale prices during this period. While increasing variable renewable generation was found to result in reduced wholesale electricity prices, lower natural gas prices over this period was the dominant driver of declining average wholesale prices. In MISO, solar and wind generation were found to account for $0.60/MWh of the drop in average wholesale prices (at the Cinergy/Indiana Hub) from $50.71/MWh in 2008 to $29.38/MWh in 2017, the drop in natural gas prices accounted for $10.90/MWh of the wholesale electricity price decline during this period. In PJM, based on an analysis of wholesale prices at the PJM Western Hub, wind and solar generation accounted for $0.40/MWh of the drop in the average annual electricity price from $69.81/MWh in 2008 to $29.73/MWh in 2017 while lower natural gas prices contributed $26.30/MWh to the price decline.[58] A range of other factors including flat electricity demand growth, declines in other fuel prices, thermal plant heat rate improvements, retirements of high cost generating plants, and in

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[55] System costs generally refer to the costs incurred by increasing variable renewable energy penetration involving grid extension and reinforcement, transmission, and balancing.

[56] Electricity acquired through the Agency's procurement events is purchased competitively in regional forward wholesale markets.

[57] Mills, A.D., et al, "Impact of Wind, Solar, and Other Factors on Wholesale Power Prices, An Historical Analysis – 2008 through 2017," Lawrence Berkeley National Laboratory, November 2019.

[58] It should be noted here that this analysis of price impacts resulting from increasing wind and solar generation only considers the wholesale market price and does not include consideration of the other environmental and economic benefits associated with renewable electricity generation.

many markets, lower priced imports, accounted for the rest of the wholesale price declines. The relatively modest wholesale price impacts of variable renewable generation in MISO and PJM are due in part to the low penetration of renewable generation in these markets during this time period. However, going forward, increasing penetration of renewable electricity can be expected to exert a larger influence on wholesale prices.

Another study developed a higher estimate of the impact of renewable resource generation on wholesale energy prices in MISO and PJM which ranged from $1.00/MWh to $6.70/MWh for utility-scale wind projects with data analyzed for periods covering 2008 through 2016.[59]

To quantify the relative benefits of wholesale price reductions that could be related to the IPA's procurement of renewable resources, these price reductions were applied to the renewable energy associated with the RECs delivered under contract for Ameren (MISO $0.60/MWh) and ComEd (PJM $0.40/MWh). The estimated wholesale price benefits for the 2020-21 delivery year are $1,246,172 for Ameren, $1,822 for MidAmerican, and $280,982 for ComEd. Using the upper end of the range of wholesale price impact estimates the price benefits could range as high as $13.9 million for Ameren, $4.7 million for ComEd, and $20,341 for MidAmerican.

The above studies focused on the impact of renewable generation on wholesale power prices there have been limited studies on the impact on capacity prices. FERC has highlighted the price suppression concerns of renewables on capacity prices in PJM in the docket dealing with (i) Calpine's complaint that PJM's Minimum Offer Price Rule ("MOPR") is unjust and unreasonable because it does not address the impact of subsidized existing resources on the capacity market, and (ii) PJM's filing consisting of two alternate proposals designed to address the price suppressing effects of state out-of-market support for certain resources.[60] FERC, in their order noted as follows:

> *"PJM, however, recognizes that in today's market, even if a load-serving entity's or a state's primary goal may not be to suppress price, <u>the growing use of out-of-market support of renewable resources can have a significant effect on prices</u>. PJM presents evidence showing that <u>the MW-level of renewable resources receiving out-of-market support has increased significantly and raises price suppression concerns</u>, similar to other resources receiving out-of-market support. Intervenors echo this same concern."[61] (Underlining added for emphasis)*

[59] "Cost Analysis of Renewable Energy Deployment in Illinois," The Power Bureau, April 2021.

[60] Order Rejecting Proposed Tariff Revisions, Granting in Part and Denying in Part Complaint, and Instituting Proceeding under Section 206 of the Federal Power Act, 163 FERC ¶ 61,236, FERC Docket No. EL16-49-000 et al, June 29, 2018 ("The June 29, 2018 Order").

[61] Id. at p.102.

Following up on their June 29, 2018 Order, FERC issued another order directing PJM to submit a replacement rate that extended the MOPR to resources receiving out-of-market payments. FERC, in that order noted as follows:

> *"The evidence in this proceeding shows that RPS programs are growing at a rapid pace, and resources participating in these programs will increasingly have the ability to suppress capacity market prices."[62] (Underlining added for emphasis)*

A previous simulation modeling study conducted by the LBNL assessed the impact of variable renewable resources on wholesale electricity prices in four market areas including the California Independent System Operator (CAISO), the Electric Reliability Council of Texas (ERCOT), the Southwest Power Pool (SPP), and the New York Independent System Operator (NYISO). This assessment compared the change in prices from 2016 to 2030 of a low variable renewable energy scenario that froze renewable penetration in each market area at 2016 levels with a 40% penetration of a mix of wind and solar generation in 2030. The 2016 renewable generation penetration levels were 21% in CAISO, 13.25% in ERCOT, 19% in SPP, and 3.8% in NYISO, renewable generation in the latter markets areas was predominantly wind. Although specific to the market areas analyzed, the findings support the contention that increasing variable renewable energy generation in competitive wholesale electricity markets would result in a general decrease in average annual hourly wholesale electricity prices.[63] In these market areas, the reduction in hourly average annual electricity prices ranged from 4% to 21% at the simulated 40% penetration levels as compared to the 2016 renewable penetration levels.

MISO's 2011 launch of the Dispatchable Intermittent Resources ("DIRs") program allows registered intermittent (variable) generation (mostly wind generators) to participate in the Real-Time Energy Market and set the Real-Time price. Wind generation resources in MISO receive production tax credits, which allow these resources to submit negative energy offers in the energy market. Negative price hours are usually correlated with higher variable renewable energy generation, especially during low system loads. The low marginal-cost generation including negative price bidding shifts the supply curve out to the right reducing near-term wholesale prices.[64]

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[62] Order Establishing Just and Reasonable Rate, 169 FERC ¶ 61,239, FERC Docket No. EL18-178-000 (Consolidated), December 19, 2019.

[63] J. Seel; A. Mills; R. Wiser; "Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices and on Electric-Sector Decision Making." Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, May 2018.

[64] Wiser, R.; A. Mills; J. Seel; T. Levin; A. Botterud; "Impacts of Variable Renewable Energy on Bulk Power System, Assets, Pricing and Costs." Lawrence Berkeley National Laboratory and Argonne National Laboratory. November 2017.

In the 2020 PJM State of the Market Report, the PJM Market Monitor reported that "In 2020, 92.8 percent of the wind marginal units had negative offer prices, 7.2 percent had zero offer prices and none had positive offer prices."[65] The implications from the PJM Market Monitor report suggests that wind units in PJM also exert downward pressure on LMPs.

These analyses of the downward impacts on LMPs are focused on reductions at the wholesale level and are not necessarily directly or immediately reflected in the retail rates customers pay.

b) Economic Development Opportunities

In 2016, the Illinois State University's Center for Renewable Energy issued "Economic Impact: Illinois Wind Energy Development," a report that modeled the economic impact of wind energy on Illinois' economy by entering wind project-specific information into the NREL's Jobs and Economic Development Impact ("JEDI") model. The model was used to estimate the income, economic activity, and number of job opportunities accruing to the state from the wind projects that have generating capacities of larger than 50 MW. The report estimated that the development of the 25 largest Illinois wind farms installed at the time of the analysis, accounting for 3,610 MW of nameplate capacity out of a total nameplate capacity for all wind projects in the state of 3,842 MW, was responsible for 20,173 full-time equivalent jobs in Illinois during construction and 869 permanent jobs, and would generate a total economic benefit of $6.4 billion[66] during the construction and typical 25-year operational lives of the projects of about $250 million on an annualized basis. The U.S. Department of Energy lists the 2020 installed wind capacity in Illinois to be 6,409 MW which reflects a 13% increase in installed wind capacity since 2019.[67]

The U.S. Energy Information Administration reported that as of October 2021 installed solar PV capacity in Illinois was 1,149.4 MW up from 437.7 MW in October 2020.[68] Small-scale solar installations (facilities of less than 1 MW) accounted for 755.4 MW of the solar capacity. During this period utility-scale PV capacity increased to 394 MW. The Solar Energy Industries Association ("SEIA") data on the solar industry in Illinois indicated that solar employment in Illinois in 2020 totaled 5,259.[69]

The wind reports by Illinois State University found that renewable power development leads to the creation of temporary and permanent jobs requiring highly skilled workers in the fields of

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[65] Monitoring Analytics, LLC, 2020 State of the Market Report for PJM, March 11, 2021. Volume 2 at 176.

[66] Economic Impact: Illinois Wind Energy Development at 6.

[67] U.S. Department of Energy, WINDExchange, Installed Wind Capacity, accessed January 10, 2022. The DOE installed capacity data is based on the American Wind Energy Association Quarterly Market Report.

[68] U.S. Energy Information Administration, Electric Power Monthly, December 2021, hrrps://www.eia.gov/electricity/monthly/current_month/epm.

[69] SEIA, Solar Spotlight Illinois, Illinois Solar Factsheet Q4 2021.

construction, management, and engineering.[70] Construction phase jobs typically last anywhere from 6 months to over a year, while operational jobs, including operations and maintenance positions, last the life of the generating facility, typically 20-30 years.[71]

The jobs and economic benefits estimated in the wind report included "turbine and supply chain impacts," which can also be referred to as "indirect impacts."[72] 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. 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 are also indirect impacts.[73] The estimated benefits also included local spending by employees working directly or indirectly on the wind farm project who receive their paychecks and then spend money in the community.[74] Additional economic impacts referred to in the study as "induced impacts" were also considered, these impacts result from changes in household spending in the areas surrounding the wind project development due to increased income brought about by the direct and indirect impacts.[75] The solar report showed similar types of economic benefits would be associated with the development of photovoltaic generating facilities.

The analysis in the wind report also determined the 25 largest wind projects in Illinois are estimated to generate more than $30.4 million in annual property taxes.[76] A recent analysis of historical property taxes in Illinois showed that in 2019 utility-scale wind and solar projects paid $41.4 million in property taxes and a combined $49 million in state and local taxes.[77] Local governments can also receive significant amounts of revenue from permitting fees.[78] Benefits to landowners identified included revenue from leasing their land, which the report found amounted to almost $14 million annually.[79] There may be some local concerns such as wear and tear on roads during

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

[71] Id.

[72] Id. at 19.

[73] Id. at 20.

[74] Id. at 20.

[75] Id. At 20.

[76] Id. at 23.

[77] "Economic Impact of Wind and Solar Energy in Illinois and the Potential Impacts of Path to 100 Legislation," David G. Loomis, Strategic Economic Research, LLC, December 2020.

[78] Id. at 18.

[79] The study noted that these payments to landowners usually extend over the 25-year life of the project and can involve adjustments for inflation which would result in higher payments over time.

construction, unfunded decommissioning cost liability, and possibly lowered land values that should be considered when evaluating any specific project's impacts.

Other entities have published employment estimates regarding the impact of wind and solar development in Illinois. According to the American Wind Energy Association, wind power supported 8,001-9,000 direct and indirect jobs in Illinois during 2019.[80] This apparently includes manufacturing jobs, which may be supported by wind generation located outside Illinois. The American Wind Energy Association also reported that in 2019 the wind industry in Illinois made annual state and local tax payments of $49 million and $37 million in land lease payments. The Clean Jobs Midwest Illinois Fact Sheet reported that in 2020 there were an estimated 17,608 jobs in renewable energy generation in Illinois.[81]

Renewable resource development in Illinois moving forward will have significant, continuing economic and environmental impacts on the state. The development and installation of new renewable generation is expected to expand significantly with the enactment of Public Act 102-0662 which increases RPS goals, in particular by increasing capacity for the Adjustable Block Program, targets for utility-scale wind and solar, and new options for very large customers to directly procure RECs from new wind and solar projects.

The Agency's renewable energy procurement plans include support for the development of utility-scale solar as well as community solar and photovoltaic distributed generation ("DG"). DG includes residential solar and commercial and industrial solar with a capacity of less than 5 MW.[82] The Agency procures DG and community solar RECs through the Adjustable Block and Illinois Solar for All programs. Based on the range of emissions benefits utilized above and the actual delivery quantity of 537,754 ABP RECs for 2020-21, the ABP emissions benefits for 2020-21 would range from a low of $9.8 million to a high of $40.7 million. As additional projects under contract reach energization and begin delivery RECs, that range will climb significantly in 2021-22 and even more across future delivery years with the implementation of Public Act 102-0662.

Distributed generation, community solar, and utility-scale solar PV offer economic and environmental benefits, but to a differing degree. On a levelized cost of energy basis (exclusive of federal tax benefits from the Investment Tax Credit and the Production Tax Credit) utility-scale PV is substantially less expensive with costs in the range of $28 to $41/MWh as compared with $147 to $221/MWh for residential rooftop solar, $67 to $180/MWh for commercial and industrial

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[80] American Wind Energy Association, Wind Energy in Illinois, accessed November 20, 2020.

[81] Clean Jobs Midwest Illinois Fact Sheet. http://www.cleanjobsmidwest.com/state/illinois, accessed January 12, 2022.

[82] Prior to the enactment of Public Act 102-0662, the limit was 2 MW.

rooftop solar, and $59 to $91/MWh for community solar.[83] The lower cost utility-scale PV generation means that more solar generation can be procured maximizing the environmental and price impact benefits at the lowest overall system cost.[84] In this case, the Agency can procure more RECs from utility-scale projects at a lower total cost than a similar amount of RECs from DG or community solar. The comparative economics of DG versus utility-scale PV are heavily impacted by net metering policies. Net metering improves the economics of DG by allowing the DG systems to sell unused electricity back to the grid at retail prices. While utility-scale systems result in more renewable generation and more emissions benefits for the same cost, DG systems offer additional benefits in terms of greater local employment impacts, the potential to avoid some transmission and distribution system investments and distributing the benefits of renewable resource electricity to a more diverse range of participants in terms of income strata and geographic location.

The IPA's incentives for the development of photovoltaic distributed generation projects and community solar projects will have a wide range of local impacts as those projects are expected to be spread throughout the state. Some employment impacts are already being observed: since more than 86 percent of the solar capacity added in 2020 involved projects of 1 MW or less, most of the 2020 jobs in the solar industry are focused on small scale distributed PV generation which is a focus of the ABP.

c) Workforce Diversity and Use of Graduates of Job Training Programs

The Revised Long-Term Renewable Resources Procurement Plan contained a new requirement applicable to ABP Approved Vendor[85] Annual Reports, requiring reporting on "[o]ther information related to ongoing program participation, including use of graduates of job training programs and other information related to increasing the diversity of the solar workforce."[86]

The Agency conducted a stakeholder feedback process on how to collect this information in June of 2020 and finalized the reporting requirements in July of 2020.[87] Those finalized reporting requirements included a provision that "[t]he Agency will publicly report aggregated data and other information from the Annual Reports that does not identify the specific Approved Vendor."

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[83] Lazard's Levelized Cost of Energy Analysis, Version 15.0, October 2021, lazard.com/media/451881/larzards-levelized-cost-of-energy-version-150-vf.pdf.

[84] Tsuchida, B. et. al., "Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area," The Brattle Group, July 2015, brattle.com/news-and-knowledge/publications/comparative-generation-costs-of-utility-scale-and-residential-scale-pv-in-xcel-energy-colorados-service-area.

[85] Approved Vendors are the entities that receive contracts for the delivery of RECs to the utilities in the ABP, Approved Vendors range from vertically integrated marketing, engineering, and installation companies, to aggregators who manage RECs for smaller installers, to special purpose entities created for the development and financing of individual solar projects.

[86] See page 164 of the Revised Plan.

[87] See: https://illinoisabp.com/wp-content/uploads/2020/07/Job-Training-Report-Requirements-7-30-20.pdf.

Information provided by Approved Vendors in response to this job training and diversity requirement was submitted at the Approved Vendor level (rather than reporting for each ABP project separately) and for this report covers the period from June 1, 2020 through May 31, 2021. Employment information was reported for two categories: direct ("hiring and employment by the Approved Vendor, e.g., staff on the Approved Vendor's payroll") and indirect ("hiring and employment conducted by the Approved Vendor's Designees, installers, marketing/sales sub-contractors, and other entities with which it works as it relates to the marketing, sale, development, and operation of projects participating in the Adjustable Block Program"). Approved Vendors were instructed to only report only on their Illinois-based workforce.

While the Agency believes that the data reported herein provides a reasonable snapshot of the solar industry in Illinois, the Agency notes several limitations of this data. First, this data is self-reported and has not been independently verified. Second, due to the varied nature of the business models within the solar industry, what may be a direct job function for one entity might be an indirect job function for another entity (e.g., if sales and marketing are conducted in-house or outsourced, or if an Approved Vendor conducts installations itself or subcontracts that work). Third, some Approved Vendors, notably those serving as aggregators who manage REC contracts and delivery obligations for smaller solar firms, reported that it was difficult to collect data from all of the entities with which they worked. In such cases, indirect hiring may be underreported. And fourth, some Approved Vendors may have REC delivery contracts for projects which had not yet commenced construction during the reporting period. Alternatively, for many projects (particularly community solar projects), some project development activities would have also occurred before the reporting period.

The following tables contain the aggregated information collected from Approved Vendors.

Workforce Diversity

	Direct (FTE[88])	Indirect (FTE)	Total (FTE)	Direct (%)	Indirect (%)	Total (%)
Race						
Black or African-American	125	279	404	4.0%	7.0%	5.7%
Hispanic or Latinix	312	571	883	10.1%	14.4%	12.5%
Asian	43	54	97	1.4%	1.4%	1.4%
American Indian or Alaska Native	12	9	21	0.4%	0.2%	0.3%
Native Hawaiian or Other Pacific Islander	14	2	16	0.5%	0.1%	0.2%
Total[89]	506	914	1,421	16.0%	23.0%	20.08%
Two or more races	51	89	140	1.6%	2.2%	2.0%
Gender						
Female	393	416	819	21.5%	15.1%	17.7%
Non Binary	10	0	10	0.5%	0.0%	0.2%
Disabled	9	6	15	0.5%	0.2%	0.3%

Job Training Graduate Hiring

Program	Direct	Direct	Direct	Indirect	Indirect	Indirect
	Full Time	Part Time	Temp.	Full Time	Part Time	Temp.
Solar Training Pipeline Program	30	2	14	199	2	52
Craft Apprenticeship Program	480	0	0	937	7	36
Multi-Cultural Jobs Programs	10	0	10	23	10	25
Other[90]	0	0	0	6	28	5
Total	520	2	24	1,165	47	118

[88] FTE: Full-Time Equivalent.

[89] Some respondents may have identified more than one race and therefore some numbers may overlap.

[90] Includes internal training programs and IBEW apprenticeships.

(13) Rate Impacts on Eligible Retail Customers

> ***"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."[91]***

This section of the report also includes estimates of bill impacts determined by analysis of the load of each eligible customer class, numbers of customers, and bill estimates contained in publicly available utility tariff and rate case filings. For the purposes of determining the total bill impact, this section of the 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." The bill impacts are presented both as a percentage of an average customer bill for that class and as cents per kilowatt-hour.

These breakouts provide the rate impact associated with the Agency's procurement of renewable resources. When multiplied by the overall billing determinants, the values also provide the total dollar impact on the annual electricity bills of each customer class. Results for each electric utility and corresponding customer class are presented for ComEd in Table 6 and Table 7, for Ameren Illinois in Table 8 and Table 9, and for MidAmerican in Table 10 and Table 11.[92]

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[91] 20 ILCS 3855/1-125(13).

[92] ComEd, Ameren Illinois, and MidAmerican provided the information in these tables in response to the IPA's data requests issued January 4, 2022.

ComEd

Table 6: Rate Impact for Customers Taking Supply from ComEd[93]

Customer Class	Description	2020-21 Delivery Year
Single Family No Electric Space Heat	Revenue/kWh	$0.1442
	REC/kWh	$0.00189
	Ratio (REC/Revenue)[94]	1.31%
Multi Family No Electric Space Heat	Revenue/kWh	$0.1560
	REC/kWh	$0.00189
	Ratio (REC/Revenue)	1.21%
Single Family With Electric Space Heat	Revenue/kWh	$0.1111
	REC/kWh	$0.00189
	Ratio (REC/Revenue)	1.70%
Multi Family With Electric Space Heat	Revenue/kWh	$0.1215
	REC/kWh	$0.00189
	Ratio (REC/Revenue)	1.56%
Watt-hour	Revenue/kWh	$0.1605
	REC/kWh	$0.00189
	Ratio (REC/Revenue)	1.18%
Small Load (< 100 kW)	Revenue/kWh	$0.1168
	REC/kWh	$0.00189
	Ratio (REC/Revenue)	1.62%

[93] Overall bill (e.g. Revenue/kWh) includes fixed supply charges, RTO services charges, delivery services charges (customer charge, standard metering service charges, distribution facilities charges, and Illinois Electricity Distribution Tax charge), other environmental cost recovery and energy efficiency & demand adjustments, franchise cost additions, and municipal and state taxes. The REC/kWh value is equal to the cost of renewable resources in the delivery year, divided by the sum of the actual load of eligible retail customers.

[94] This value represents the amount that RECs cost each customer of that delivery year class as a percentage of the amount paid for total "annual electricity bills," including taxes. Thus, a Rate Impact of 1.31% (Single Family No Electric Space Heat) means that 1.31% of the total electricity bill of a customer of that class in the 2020-21 delivery year was spent on contracts for renewable energy resources.

Table 7: Dollar Impact for Customers Taking Supply from ComEd[95]

Customer Class	Description	2020-2021 Delivery Year
Single Family No Electric Space Heat	Usage (kWh)	13,196,036,599
	Dollar Impact	$24,940,509
Multi Family No Electric Space Heat	Usage (kWh)	3,639,328,351
	Dollar Impact	$6,878,331
Single Family With Electric Space Heat	Usage (kWh)	340,302,996
	Dollar Impact	$643,173
Multi Family With Electric Space Heat	Usage (kWh)	969,177,524
	Dollar Impact	$1,831,746
Watt-hour	Usage (kWh)	179,118,663
	Dollar Impact	$338,534
Small Load (< 100 kW)	Usage (kWh)	3,714,395,563
	Dollar Impact	$7,020,208

[95] Usage values were reported by ComEd. Dollar Impact values were calculated by multiplying the Usage by the REC/kWh reported in Table 6.

Ameren Illinois

Table 8: Rate Impact for Customers Taking Supply from Ameren Illinois[96]

Customer Class	Description	2020-21 Delivery Year
Residential Service (DS-1)	Revenue/kWh	$0.105
	REC/kWh	$0.001805
	Ratio (REC/Revenue)[97]	1.72%
Small General Service (DS-2)	Revenue/kWh	$0.104
	REC/kWh	$0.001805
	Ratio (REC/Revenue)	1.74%
General Service & Large General Service (DS-3 and DS-4)[98]	Revenue/kWh	$0.060
	REC/kWh	$0.001805
	Ratio (REC/Revenue)	3.01%

[96] Overall bill (i.e. Revenue/kWh) includes fixed supply charges, RTO services charges, delivery services charges (customer charge, standard metering service charges, distribution facilities charges, and Illinois Electricity Distribution Tax charge), other environmental cost recovery and energy efficiency & demand adjustments, franchise cost additions, and municipal and state taxes. The REC/kWh value is equal to the cost of renewable resources in the delivery year, divided by the sum of the actual load of eligible retail customers.

[97] This value represents the amount that RECs cost each customer of that delivery year class as a percentage of the amount paid for total "annual electricity bills," including taxes. Thus, a Rate Impact of 1.72% (Residential Service) means that 1.72% of the total electricity bill of a customer of that class in the 2020-21 delivery year was spent on contracts for renewable energy resources.

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

Table 9: Dollar Impact for Customers Taking Supply from Ameren Illinois[99]

Customer Class	Description	2020-21 Delivery Year
Residential Service (DS-1)	Usage (kWh)	5,065,313,083
	Dollar Impact	$9,144,916
Small General Service (DS-2)	Usage (kWh)	1,578,177,796
	Dollar Impact	$2,849,242
General Service & Large General Service (DS-3 and DS-4)[100]	Usage (kWh)	1,307,756,784
	Dollar Impact	$2,361,024

[99] Usage values were reported by Ameren Illinois. Dollar Impact values were calculated by multiplying the Usage by the REC/kWh reported in Table 8.

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

MidAmerican

Table 10: Rate Impact for Customers Taking Supply from MidAmerican[101]

Customer Class	Description	2020-21 Delivery Year
Residential	Revenue/kWh	$0.09754
	REC/kWh	$0.00124
	Ratio (REC/Revenue)[102]	1.27%
Commercial	Revenue/kWh	$0.07706
	REC/kWh	$0.00124
	Ratio (REC/Revenue)	1.61%
Industrial	Revenue/kWh	$0.04726
	REC/kWh	$0.00124
	Ratio (REC/Revenue)	2.63%
Public Authority	Revenue/kWh	$0.06311
	REC/kWh	$0.00124
	Ratio (REC/Revenue)	1.97%
Street Lighting	Revenue/kWh	$0.13626
	REC/kWh	$0.00124
	Ratio (REC/Revenue)	0.91%

[101] Overall bill (e.g. Revenue/kWh) includes fixed supply charges, RTO services charges, delivery services charges (customer charge, standard metering service charges, distribution facilities charges, and Illinois Electricity Distribution Tax charge), other environmental cost recovery and energy efficiency & demand adjustments, franchise cost additions, and municipal and state taxes. The REC/kWh value is equal to the cost of renewable resources in the delivery year, divided by the sum of the actual load of eligible retail customers.

[102] This value represents the amount that RECs cost each customer of that delivery year class as a percentage of the amount paid for total "annual electricity bills," including taxes. Thus, a Rate Impact of 1.27% (Residential) means that 1.27% of the total electricity bill of a customer of that class in the 2020-21 delivery year was spent on contracts for renewable energy resources.

Table 11: Dollar Impact for Customers Taking Supply from MidAmerican[103]

Customer Class	Description	2020-21 Delivery Year
Residential	Usage (kWh)	644,018,178
	Dollar Impact	$799,549
Commercial	Usage (kWh)	413,561,655
	Dollar Impact	$513,437
Industrial	Usage (kWh)	658,587,008
	Dollar Impact	$817,636
Public Authority	Usage (kWh)	139,488,024
	Dollar Impact	$173,174
Street Lighting	Usage (kWh)	6,862,084
	Dollar Impact	$8,519

[103] Usage values were reported by MidAmerican. Dollar Impact values were calculated by multiplying the Usage by the REC/kWh reported in Table 10.

(14) Rate Impacts on Customers of Alternative Retail Electric Suppliers

"An analysis of 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."[104]

Due to changes to Section 16-115D of the Public Utilities Act contained in Public Act 99-0906, for the 2017-18 delivery year through the 2018-19 delivery year, Section 16-115D's ARES RPS requirements were gradually phased out, with Section 16-115D's requirements applicable to only 50% of load in the first of those years and 25% of load in the second. Furthermore, ARES were no longer required to make alternative compliance payments ("ACPs") for a portion of their obligations.[105] After the 2018-19 delivery year (which ended on May 31, 2019), RPS obligations became fully consolidated under the processes identified in Section 1-75(c) of the IPA Act funded through a charge applicable to all retail customers and ARES now no longer make ACP payments.[106]

As a result, there were no ACP rates applicable to the 2020-21 delivery year (which overlaps the state Fiscal Year 2021), and thus there were no impacts on customers of alternative retail electric suppliers related from alternative compliance payments. Any rate impacts on these customers would be the same as those described for eligible retail customers in Section 13.

For reference purposes previous ACP analyses can be found in prior fiscal year annual reports.

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[104] 20 ILCS 3855/1-125(14).

[105] Additional new requirements include a change from 60% of resources coming from wind, and 6% from photovoltaics, to a combined 32% coming from wind or photovoltaics. Resources also may not come from facilities that have their costs recovered through rates regulated by a state.

[106] See https://www.icc.illinois.gov/industry-reports/renewable-portfolio-standards-requirements for a chart of year to year obligations for ARES.

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."***[107]

For the delivery year ending May 31, 2017, to the extent an ARES complied with its RPS obligations by procuring renewable energy resources, at least 60% of the renewable energy resources procured by that ARES was required to come from wind generation, while at least 6% of the renewable energy resources procured was required to come from solar PV.[108] If an ARES did not purchase at least the technology-specific sub- target levels of wind or photovoltaic renewable energy resources, then it was required to make additional ACPs at the same rate to meet those obligations. For the delivery years beginning on June 1, 2017 and June 1, 2018, 32% of the renewable energy resources procured by an ARES had to come from either wind or photovoltaics and cannot come from facilities that had their costs recovered through rates regulated by a state. For deliveries years starting June 1, 2019 ARES no longer had RPS obligations.

Up until June 1, 2017, all ACPs were deposited into the Renewable Energy Resources Fund ("RERF"), a state fund administered by the Agency to procure renewable energy resources through the purchase and retirement of RECs.[109] As of June 1, 2017, changes to Section 16-115D(d)(4.5) of the Public Utilities Act contained in Public Act 99-0906 required ACPs to be remitted to the utilities and used to support the procurement of renewable resources for the utilities by the IPA under Section 1-75(c) of the IPA Act.

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[107] 220 ILCS 5/16-115D(d)(4).

[108] 220 ILCS 5/16-115D(a)(3) (the 60% statutory wind energy minimum for ARES is lower than the 75% wind standard for utilities).

[109] 20 ILCS 3855/1-56.

A. Total Amount of ACPs Received

This report must provide the total amount of ACPs received in aggregate from ARES for each delivery year in which the ACP was in effect.[110] Under the PUA, a delivery year begins on June 1st of each calendar year.[111] 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.[112] Therefore, this report provides the aggregate total amount of ACPs for the delivery years 2009-10 through 2017-18. Table 14 shows the total ACPs for each year through 2015-2016 which were collected by the ICC and deposited into the Renewable Energy Resources Fund. Starting with the 2016-2017 delivery year, ACP payments are made to the applicable utility and are reported separately.

Table 14: Total ACPs Received by the RERF[113]

Delivery Year	Total ACPs Received
June 2009 – May 2010	$7,148,261.61
June 2010 – May 2011	$5,632,587.18
June 2011 – May 2012	$2,156,777.61
June 2012 – May 2013	$38,382,345.57
June 2013 – May 2014	$77,145,921.09
June 2014 – May 2015	$86,278,411.02
June 2015 – May 2016	$71,649,805.76
Aggregate Total	**$288,394,109.84**

ARES ACP payments were due by September 1st following the end of the delivery year. For example, for the delivery year that ended in May, 2017, payments were due September 1, 2017.[114] Payments are made in conjunction with a Compliance Report submitted to the ICC.

Table 15 shows total the ACPs collected by the utilities from ARES from for the delivery years 2016-2017, 2017-2018 and 2018-2019, the final delivery year. ComEd reported interests earned from their ACP balance in the 2019-2020 delivery year.

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

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

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

[113] Total ACPs Received does not account for expenditures (or other diversions) from the RERF and, therefore, the Aggregate Total reported in this figure will differ from the RERF balance reported in Table 16. Source: internal IPA records reconciled with the ARES reports submitted to the ICC.

[114] 220 ILCS 5/16-115D(d)(2).

Table 15: Total ACPs Collected by the Utilities[115]

Delivery Year	ComEd[116] [117]	Ameren Illinois	MidAmerican	Total ACPs
June 2016 – May 2017	$40,575,311.19	$23,375,512.09	$10,532	$63,961,355.28
June 2017 – May 2018	$74,147.65	$76,169.24	$1,951	$152,267.89
June 2018 – May 2019	$228,292.00	$67,725.00	$1,073.00	$ 297,090.00
Aggregate Total	**$42,731,063.07**	**$23,519,406.33**	**$13,556.00**	**$64,410,713.17**

The dramatic decrease in the amount of ACP payments collected by the utilities between the first two Delivery Years appears to be the result of the removal of the requirement that an ARES was required to make ACP payments for 50% of its RPS obligations as well as a very low ACP rate for the 2017-2018 delivery year (see Table 12 above). ARES appear to have complied with their RPS obligations primarily through the purchase and retirement of Renewable Energy Credits rather than making ACP payments.

The combined total of ACPs received by the Renewable Energy Resources Fund and by the utilities since the ACP compliance mechanisms was first instituted is $354,658,135.24.

B. Amount of ACPs used to purchase RECs

1. Purchases Made

Prior to May 2013, the only disbursements made from the RERF were temporary transfers of funds to the State's General Revenue Fund pursuant to 30 ILCS 105/5h(a). Of the $7,148,261.61 in total ACPs received for the 2009-10 delivery year, the State of Illinois transferred $2,000,000 on September 20, 2010 and $4,710,000 on October 15, 2010.[118] The remaining $438,261.61 was not used to purchase RECs and remained in the RERF. The State was required to repay the funds within 18 months of borrowing, and it repaid $2,000,000 to the RERF in March 2012 and the remaining $4,710,000 was repaid in April 2012. Because the funds were transferred from a non-interest earning account, no interest was paid.

[115] Source: ACP balances provided to the IPA by the respective utility.

[116] ACP payments are received in the subsequent delivery year. For purposes of this schedule, the payments are reflected in the procurement year it relates to.

[117] Interest is earned monthly. For purposes of this schedule, the amounts include the interest earned during the delivery year.

[118] 30 ILCS 105/5h(a).

In 2013, REC deliveries under the 2010 LTPPAs were curtailed due to application of the RPS budget cap.[119] Pursuant to the 2013 Procurement Plan, holders of those LTPPAs were given the option to sell curtailed RECs to ComEd with the purchases supported by the ACPs collected from customers on hourly pricing, which are distinct from ACPs collected from ARES. Those funds were insufficient to purchase all of the curtailed RECs and the IPA offered to voluntarily use the RERF to purchase remaining curtailed RECs. In May 2013, the IPA entered into contracts to purchase RECs associated with ComEd's curtailed long-term contracts that were not otherwise purchased by ComEd.[120] These purchase contracts were for the delivery year June 1, 2013 through May 31, 2014, and were for up to 121,620 RECs with no minimum delivery levels with a total value of $2.24 million. Due to improved market prices for RECs elsewhere, not all contract holders exercised their rights to deliver RECs to the IPA. A total of 74,402 RECs were delivered in the June 1, 2013 through May 31, 2014 delivery year under these contracts at a total cost of $1,719,141.52. There was no direct rate impact resulting from these purchases because they used ACP funds previously collected from ARES. As approved in ICC Docket No. 12-0544, ComEd also used ACP funds to purchase 79,674 RECs curtailed under the operation of LTPPAs in the June 1, 2013 through May 31, 2014 delivery year at a total cost of $1,647,596.

Effective June 28, 2014, Public Act 98-0672 created new subsection 1-56(i) of the Illinois Power Agency Act requiring the Agency to develop a one-time supplemental procurement plan for the procurement of renewable energy credits from new or existing photovoltaics using up to $30,000,000 from the RERF. The Supplemental Plan was developed by the IPA in 2014 and approved by the ICC on January 21, 2015. Three procurement events were conducted pursuant to the Supplemental Plan (June 2015; November 2015; and March 2016). Table 16 shows the number of RECs contracted for purchase using alternative compliance payments held in the RERF as the result of each procurement event.[121]

Table 16: Supplemental Photovoltaic Procurement RECs and RERF Funds Committed

Procurement Event	RECs Contracted For Purchase	RERF Funds Committed
June 2015	37,082	$4,999,963
November 2015	70,096	$9,999,961
March 2016	91,770	$14,999,894
Total	198,948	$29,999,818

Table 17 below documents the expenditures for RECs from those procurements as the photovoltaic projects developed pursuant to it are completed and begin operation. As of February 16, 2021,

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

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

[121] Source: SPV procurement results, internal IPA records

1,062 new photovoltaic projects have begun operation as a result of this procurement process and have delivered 100,005 RECs under five-year delivery contracts.[122]

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

Public Act 99-0524, effective June 30, 2016, included an appropriation of $12 million from the Renewable Energy Resources Fund for deposit into the Illinois Commerce Commission Public Utility Fund. The transfer occurred on June 23, 2017.

Public Act 100-0023, effective July 6, 2017, authorized transfers from special funds (such as the Renewable Energy Resources Fund) to the State's General Revenue Fund with a two-year deadline for repayment provision. On August 10, 2017, $150 million was transferred from the Renewable Energy Resources Fund to the General Revenue Fund. In April 2018, $37.5 million was repaid back to the Renewable Energy Resources Fund from the General Revenue Fund. However, on January 22, 2020, an additional $10 million was transferred from the Renewable Energy Resources Fund to the General Revenue Fund, and on March 23, 2020 another $20 million was transferred to the Health Insurance Reserve Fund. Subsequently, $24 million has been repaid in October 2021 through January 2022.

2. Changes in Spending the RERF

Public Act 99-0906, effective June 1, 2017, substantially revamped Section 1-56 of the Illinois Power Agency Act (which governs how the Agency uses the RERF). Other than expenditures previously committed via the Supplemental Photovoltaic Procurement process as described above, the remaining balance of the RERF was shifted to supporting the Illinois Solar for All Program, which is designed to create incentives for and support to the development of photovoltaic resources benefitting low-income households and communities. (Solar for All is also supported by contracts with the utilities in addition to the RERF funds.)

Details of the Illinois Solar for All Program were included in the original Long-Term Renewable Resources Procurement Plan developed by the Agency and approved by the Illinois Commerce Commission in 2018, and subsequently updated in the Revised Long-Term Renewable Resources Procurement Plan approved in 2020. See www.illinoissfa.com for more information and details on the program. As of February 15, 2022, REC contracts totaling $59,778,775 have been awarded to

[122] Unlike future REC purchases as part of the Illinois Solar for All Program which will feature upfront payments, the Supplemental Photovoltaic Procurement only pays for RECs as they are delivered.

Illinois Solar for All projects using funds from the RERF (and an additional $35,014,919 in contracts funded by the utilities).

Some of the challenges in spending the RERF that have been previously documented are resolved by this change in State law. However, the RERF remains a special State Fund and expenditures from it are only authorized pursuant to the annual appropriations process, and the RERF could be subject to future reallocations of funds to other State purposes if authorized by the General Assembly and Governor.

C. Balance in RERF

As of February 15, 2022, the RERF balance equals $28,944,714.81 . Table 17 shows the current RERF balance.[123] As discussed above, ACP payments from ARES were submitted to the utilities in recent years and were not deposited into the RERF.

Table 17: IPA RERF Balance Sheet

Date	Transaction	Amount	Cumulative Balance
Fall 2010	ACPs received	$7,148,261.61	$7,148,261.61
September 2010	Transfer to General Revenue Fund pursuant to 30 ILCS 105/5h(a)	($2,000,000.00)	$5,148,261.61
October 2010	Transfer General Revenue Fund pursuant to 30 ILCS 105/5h(a)	($4,710,000.00)	$438,261.61
Fall 2011	ACPs received	$5,606,245.18	$6,044,506.79
March 2012	Transfer in pursuant to 30 ILCS 105/5h(a)	$2,000,000.00	$8,044,506.79
April 2012	Transfer in pursuant to 30 ILCS 105/5h(a)	$4,710,000.00	$12,754,506.79
Fall 2012	ACPs received	$2,156,777.61	$14,911,284.40
Fall 2013	ACPs received	$38,382,345.57	$53,293,629.97
Winter/Spring 2014	RECs purchased per May 2013 Contracts	($1,719,141.52)	$51,574,488.45
Fall 2014	ACPs received	$77,145,921.09	$128,720,409.54
Fall 2014	Supplemental PV Procurement Expenses	($170,068.33)	$128,550,341.21
Spring 2015	Transfer to General Revenue Fund pursuant to Public Act 99-0002	($98,000,000.00)	$30,550,341.21
Spring 2015	ACPs Received	$26,342.00	$30,576,683.21
Summer 2015	Supplemental PV Procurement Expenses	($653,549.18)	$29,923,134.03
Summer 2015	SPV Deposits	$427,836.00	$30,350,970.03
Fall 2015	ACPs Received	$86,278,411.02	$116,629,381.05
Fall 2015	SPV Deposits	$492,785.00	$117,122,166.05
Spring 2016	SPV Deposits	$561,734.04	$117,683,900.09
Summer 2016	REC Payments/SPV Deposit Returns/Supplemental PV Procurement Expenses	($738,377.81)	$116,945,522.28
Fall 2016	ACPs Received	$71,649,805.76	$188,595,328.04
Fall 2016	REC Payments/SPV Deposit Returns	($728,153.71)	$187,867,174.33
Winter 2016-17	REC Payments/SPV Deposit Returns	($734,612.31)	$187,132,562.02
Spring 2017	REC Payments/SPV Deposit Returns	($660,180.37)	$186,472,381.65
Spring 2017	Transfer to Public Utility Fund pursuant to Public Act 99-0524	($12,000,000)	$174,472,381.65

[123] Source: internal IPA records

Summer 2017	REC Payments/SPV Deposit Returns	($871,070.33)	$173,601,311.32
Summer 2017	Transfer to General Revenue Fund pursuant to Public Act 100-0023	($150,000,000.00)	$23,601,311.32
Fall 2017	REC Payments/SPV Deposit Returns	($1,169,996.58)	$22,431,314.74
Winter 2017-18	REC Payments/SPV Deposit Returns	($1,235,079)	$21,196,235.74
Spring 2018	REC Payments/SPV Deposit Returns	($792,668.65)	$20,403,567.09
Spring 2018	Repayment pursuant to Public Act 100-0023	$37,500,000.00	$57,903,567.09
Summer 2018	REC Payments/SPV Deposit Returns	($1,397,724.65)	$56,505,842.44
Fall 2018	REC Payments/SPV Deposit Returns	($1,553,532.50)	$54,952,309.94
Winter 2018-19	REC Payments/SPV Deposit Returns	($1,024,176.35)	$53,928,133.59
Winter 2018-19	ILSFA Collateral Deposits	$115,384.00	$54,043,517.59
Spring 2019	REC Payments/SPV Deposits Returns	($1,689,295.05)	$52,354,222.54
Spring 2019	ILSFA Expenses	($2,036,953.03)	$50,317,269.51
Summer 2019	ILSFA Expenses	($290,061.22)	$50,027,208.29
Fall 20190	REC Payments/SPV Deposits Returns	($1,467,086.90)	$48,560,121.39
Fall 20190	ILSFA Expenses	($897,031.39)	$47,663,089.91
Fall 20190	ILSFA Collateral Deposits	$432,583.05	$48,095,672.96
Winter 2019-2020	REC Payments/SPV Deposits Returns	($935,608.35)	$47,160,064.61
Winter 2019-2020	ILSFA Expenses	($735,477.48)	$46,424,587.13
Winter 2019-2020	ILSFA Collateral Deposits	$1,798,031.16	$48,222,618.29
Winter 2019-2020	Transfer to General Revenue Fund Pursuant to Public Act 100-0023	($10,000,000.00)	$38,222,618.29
Spring 2020	Transfer to General Revenue Fund Pursuant to Public Act 100-0023	($10,000,000.00)	$28,222,618.29
Spring 2020	REC Payments/SPV Deposits Returns	($2,360,208.66)	$25,862,409.63
Spring 2020	ILSFA Expenses	($1,435,761.48)	$24,426,648.15
Spring 2020	ILSFA Collateral Deposits	$67,084.70	$24,493,732.85
Summer 2020	REC Payments/SPV Deposits Returns	($4,561,049.86)	$19,932,682.99
Summer 2020	ILSFA Expenses	($40,447.75)	$19,892,235.24
Fall 2020	REC Payments/SPV Deposits Returns	($1,456,509.60)	$18,435,725.64
Fall 2020	ILSFA Expenses	($1,037,583.88)	$17,398,141.76
Fall 2020	ILSFA Collateral Deposits	$135,537.48	$17,533,679.24
Winter 2020-2021	REC Payments/SPV Deposits Returns	($930,699.52)	$16,602,979.72
Winter 2020-2021	ILSFA Expenses	($402,604.22)	$16,200,375.50
Spring 2021	REC Payments / SPV Deposit Returns	($373,918.93)	$15,826,456.57
Spring 2021	ILSfA REC Payments	($2,136,878.45)	$13,689,578.12
Spring 2021	ILSfA Expenses	($681,878.69)	$13,007,699.43
Spring 2021	ILSfA Collateral Deposits	$322,785.17	$13,330,484.60
Summer 2021	REC Payments / SPV Deposit Returns	($1,149,321.66)	$12,181,162.94
Summer 2021	ILSfA REC Payments	($2,926,643.00)	$9,254,519.94
Summer 2021	ILSfA Expenses	($1,200,343.16)	$8,054,176.78
Fall 2021	REC Payments / SPV Deposit Returns	($1,116,449.98)	$6,937,726.80
Fall 2021	ILSfA REC Payments	$13,500.00	$6,951,226.80
Fall 2021	ILSfA Expenses	($433,881.24)	$6,517,345.56
Fall 2021/Winter 2022	Repayments from General Revenue Fund	$24,000,000.00	$30,517,345.56
Winter 2021-2022	REC Payments / SPV Deposit Returns	($321,477.31)	$30,195,868.25
Winter 2021-2022	ILSfA REC Payments	($891,658.74)	$29,304,209.51
Winter 2021-2022	ILSfA Expenses	($647,549.21)	$28,656,660.30
Winter 2021-2022	ILSfA Collateral Deposits	$288,054.51	$28,944,714.81

Appendix A

Illinois Power Agency

Fiscal Year 2021

Financial Statement and Notes (Unaudited)

Appendix B

Illinois Power Agency

Fiscal Year 2021

Summary of Funds on a Cash Basis