Soot to Solar

Illinois's Clean Energy Transition
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Technical Appendix: Methodology and Assumptions

Union of Concerned Scientists

This document describes the methodology and assumptions that the Union of Concerned Scientists (UCS) used for the development of the analysis *Soot to Solar: Illinois's Clean Energy Transition*.

Regional Energy Deployment System (ReEDS)

UCS employed the National Renewable Energy Laboratory's (NREL) Regional Energy Deployment System (ReEDS)—a capacity-planning model for the deployment of electric power–generation technologies in the contiguous United States through 2050—to analyze the effects of Illinois's Future Energy Jobs Act (FEJA) and additional coal plant retirement in Illinois and the United States.

ReEDS is designed to analyze in particular the impacts of state and federal energy policies, such as clean energy and renewable energy standards, for reducing carbon emissions. ReEDS provides a detailed representation of electricity generation and transmission systems. It specifically addresses issues, such as transmission, resource supply and quality, variability, and reliability, that are related to renewable energy technologies (NREL 2016a).

UCS used the 2016.RE.TaxExt.P1 version of ReEDS for its analysis. Based on project-specific data and estimates from recent studies, we made a few adjustments to NREL's assumptions on renewable and conventional energy technologies, as described in more detail in "Overall Model Assumptions" just below. Our assumptions for the policies being tested in our analysis are described in "Policy Assumptions for Scenarios" that appears later in this document.

Overall ReEDS Model Assumptions

COST AND PERFORMANCE

The cost and performance assumptions for electricity-generating technologies used in the ReEDS analysis are shown in Tables TA-6 and TA-7 below. We compared our key assumptions to the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2018 assumptions (EIA 2018), which are widely used for energy policy analysis and provide a well-recognized industry benchmark.

We made several changes to NREL's capital-cost assumptions. The 2016.RE.TaxExt.P1 version of ReEDS uses the EIA's AEO 2015 cost assumptions for conventional plants; our revisions are based on AEO 2018 assumptions for capital costs, operating and maintenance (O&M) costs, and heat rates.

NREL provides a set of projections, which users can easily select, regarding cost and performance assumptions on renewable energy technologies. Our choices of these projections were consistent with the corresponding assumptions underlying the DOE Wind Vision report (DOE 2015) and the Annual Technology Baseline 2017 report (NREL 2017a). The main changes we made were in the following areas.

- **Coal**. For new integrated gasification and combined-cycle plants and for supercritical pulverized coal plants, we used NREL's assumptions, which are based on the EIA's higher costs for a single-unit plant (600–650 megawatts (MW)), as opposed to dual-unit plants (1200–1300 MW). For plants with carbon capture and sequestration, we used the assumptions used by NREL and the EIA.
- **Natural gas**. For new plants, we used NREL's assumptions, which are based on the average of the EIA's assumptions for conventional and advanced plants in 2018.
- **Nuclear**. We use the EIA's assumed costs for 2018. This is a conservative assumption as recent projects in the United States (Vogtle and V.C. Summer) have significantly higher costs than EIA's assumptions and have experienced considerable cost overruns and delays. We also assumed that existing plants will receive a 20-year license extension, allowing them to operate for 60 years, and that they will then be retired because of safety and economic issues. To date, no existing plant has received an operating license extension beyond 60 years.
- **Onshore and offshore wind**. We used NREL's cost and performance projections from its median cost-reduction case, as described in the DOE Wind Vision report (DOE 2015). These cost and performance projections are based on NREL's estimate of median values from its review of literature.
- **Utility-scale solar photovoltaics (PV)**. We use NREL's 2017 Annual Technology Baseline cost and performance projections from its mid-cost case.

- **Distributed solar PV**. ReEDS does not endogenously simulate the uptake of distributed PV systems (those installed on site by residential or commercial customers). Instead, users must select the appropriate projections for uptake of these systems as an exogenous input to the model based on projections from NREL's dGen model (NREL 2016b). For our reference case, we used NREL projections based on NREL's 2017 Annual Technology Baseline mid-cost case.
- **Concentrating solar power plants**. We assumed that concentrating solar power plants will include six hours of storage and exhibit the capital and O&M cost projections of NREL's 2017 Annual Technology Baseline mid-cost case.
- **Biomass.** We used the EIA's initial capital costs for new fluidized-bed combustion plants and for biomass co-firing with coal, but we did not include the EIA's projected cost reductions due to learning because we assumed that these were mature technologies. We also used a slightly different biomass supply curve from those of the EIA and NREL, based on a UCS analysis of data from the DOE's Updated Billion Ton study, which included additional sustainability criteria (ORNL 2011). We project a potential biomass supply of 680 million tons per year by 2030 (UCS 2012). Further, we limited the coal capacity that can be retrofitted for co-firing biomass to 10 percent of a plant's capacity—not the 15 percent maximum used in NREL assumptions.
- **Geothermal and landfill gas**. We did not make any changes to NREL's assumptions for these technologies.
- **Storage technologies**. We assumed that utility-scale batteries are four-hour-duration lithium-ion systems with cost assumptions based on recent studies (Lazard 2017; Cole et al. 2016).
- **Hydro**. In order to reflect the long lead times for planning, permitting, and building large hydro dams, we restricted the construction of such facilities until after 2020. Based on the 2016 Hydropower Vision study (DOE 2016), we increased the costs of non-powered dams to be twice those assumed by NREL. We did not make any other changes to NREL's assumptions for the hydro supply curves, which are site-specific.

ELECTRICITY SALES AND ENERGY EFFICIENCY PROJECTIONS

ReEDS does not endogenously model electricity sales or efficiency; instead, users provide assumptions of future use. As a default, electricity sales are taken from the EIA's AEO 2018 projections. ReEDS starts with the 2010 electricity sales for each state, then projects future electricity sales using the growth rate for the appropriate census region from the AEO 2018 reference case. We adjusted these projections to account for reductions in load growth resulting from currently enacted state energy efficiency resource standards (EERS) that are not included in the AEO 2018. Our adjustments follow the approach used by the Environmental Protection Agency (EPA) in *its Projected Impacts of State Energy Efficiency and Renewable Energy Policies* report (EPA 2014). We assumed full compliance with Illinois EEPS policies that had been enacted as of the end of December 2017.

We modeled the EERS targets laid out in FEJA. Under FEJA, Commonwealth Edison (ComEd) is required to achieve a cumulative 21.5 percent reduction in energy use, and Ameren Illinois is required to achieve a cumulative reduction of 16 percent, by 2030. To model these targets, we referenced ComEd and Ameren Illinois's current 2018–2021 energy efficiency and demand response plans. Ameren Illinois modified its four-year plan in March 2018 to lower its energy efficiency targets (IL SAG 2018). Our analysis reflects that change. We assumed a 10.7-year measure life, based on consultations with Energy Futures Group. Table TA-1 shows the assumed annual megawatt-hour (MWh) sales, and Table TA-2 shows the assumed average incremental annual savings required by statute in each multi-year utility plan (including voltage optimization).

TABLE TA-1. **Assumed Annual MWh Sales**

Utility	No Opt Outs	Opt Out %	With Opt Outs
ComED	88,000,000	11%	78,654,471
Ameren	36,900,000	24%	27,909,853
TOTAL	124,900,000	15%	106,564,853

TABLE TA-2. **Assumed Average Incremental Annual Saving Required in Each Multi-Year Plan (Including Voltage Optimization)**

	Com Ed		Ameren		Statewide	
	No Opt Outs	**All Opt Outs**	**No Opt Outs**	**All Opt Outs**	**No Opt Outs**	**All Opt Outs**
1st Plan (2018-2021)	2.19%	1.96%	1.32%	0.99%	1.93%	1.67%
2nd Plan (2022-2025)	2.26%	2.02%	1.47%	1.11%	2.02%	1.75%
3rd Plan (2026-2030)	2.00%	1.79%	1.48%	1.12%	1.85%	1.59%

STATE RENEWABLE PORTFOLIO STANDARD (RPS) PROGRAMS

ReEDS uses RPS data from a 2015 Bloomberg New Energy Finance (BNEF) RPS database. We adjusted ReEDS' representation of the state programs to account for recent legislation and demand forecasts. Our adjustments are based on the Lawrence Berkeley National Laboratory's 2017 RPS Annual Status Report (LBNL 2017) and industry reports and projections in NREL's Annual Technology Baseline (NREL 2017a).

Under FEJA, Illinois may procure renewable energy credits (RECs) from projects located in Illinois or in nearby states (Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, and Wisconsin). However, while projects in Illinois automatically qualify for REC procurement, projects in nearby states must satisfy a set of public interest criteria established by the Illinois Power Agency, and their costs cannot be recovered through rates approved by a state utility commission to be eligible for procurement. Based on these limitations, we capped the amount of RECs assumed to come from projects in nearby states to 20 percent, an assumption that we then cross-checked with stakeholder groups for reasonableness. Illinois municipal utilities and power cooperatives are not required to comply with the Illinois RPS but may choose to pursue their own renewable energy goals and that may include purchasing out-of-state RECs.

Accordingly, full compliance with the Illinois RPS does not necessarily equate to 25 percent of Illinois electricity sales in our analysis.

ACCOUNTING FOR RECENT OR PLANNED CHANGES TO GENERATING RESOURCE OR TRANSMISSION AVAILABILITY

We reviewed ReEDS assumptions for expected changes in power-plant capacity and transmission lines in the near term and compared that with our understanding, based on S&P Global Market Intelligence Platform data and industry reports and projections, of real-world conditions. Our updates to ReEDS included:

- Accounting for prescribed builds of newly constructed or under construction generating resources (including natural gas, nuclear, coal, wind, and utility-scale solar facilities) using a combination of S&P analyst and industry association data published as of March 2018
- Accounting for recent or recently announced coal-plant retirements through 2030 based on data published as of March 2018
- Accounting for recent or recently announced nuclear-plant retirements based on data published as of April 2018
- Accounting for transmission projects under construction or in an advanced stage of development using a combination of S&P and industry association data published as of April 2018

CALCULATION OF THE MONETARY VALUE OF CARBON DIOXIDE (CO_2) REDUCTION BENEFITS

To determine the monetary value of CO_2 reductions, we used the US government's estimates of the "social cost of carbon"—an estimate of the damages, expressed in dollars, resulting from the addition of one metric ton of CO_2 to the atmosphere in a given year. We multiplied the tons of CO_2 reduced in our scenarios by the social cost of carbon to derive the CO_2-reduction benefits or the avoided damages.

We used the updated values for the social cost of carbon that were reported in the EPA's *Regulatory Impact Assessment for the Clean Power Plan Final Rule* (EPA 2015), shown here in Table TA-3.

TABLE TA-3. **Values for Social Cost of Carbon**

Year	2017$ per ton of CO_2
2018	$47
2020	$50
2025	$54
2030	$59

Note: Value assumes a 3 percent discount rate.

SOURCE: EPA 2015, TABLE 4-2

CALCULATION OF THE MONETARY VALUE OF SULFUR DIOXIDE (SO_2) AND NITROGEN OXIDES (NO_X) REDUCTION BENEFITS

To value SO_2 and NO_x emission reductions, we again used estimates from the EPA Regulatory Impact Assessment for the Clean Power Plan Final Rule of the dollar value of the health benefits per ton of SO_2 and NO_x reduced by different industrial sectors, including the electricity sector (EPA 2015).

In particular, for the 2020 emissions reductions generated in our models, we used the values in the EPA's Table 4-7. There, these values are expressed in 2011$ using a 7 percent discount rate, so we converted them to 2017$ so as to be consistent with other dollar values in our analysis. For 2025 and 2030, we used the values in Tables TA 6 –TA 9, again converted to 2017$.

TABLE TA-4. **Prescribed Dates for the Coal Retirement Scenarios**

Scenario	Plant	Unit #	Retirement Date
Waukegan/Edward			
	Waukegan	7	2020
	Waukegan	8	2022
	Edwards	2	2020
	Edwards	3	2022
Dynegy-Vistra			
	Coffeen	1	2024
	Coffeen	2	2026
	Edwards	2	2020
	Edwards	3	2022
	Havana	6	2026
	Joppa	1	2020
	Joppa	2	2022
	Joppa	3	2022
	Joppa	4	2024
	Joppa	5	2024
	Joppa	6	2026
	Newton	1	2030
	Duck Creek	1	2030
	Hennepin	1	2020
	Hennepin	2	2030
	Baldwin	1	2020
	Baldwin	2	2020

POLICY ASSUMPTIONS

For this analysis, we compared a number of scenarios: the pre-FEJA baseline scenario, the FEJA scenario, the Waukegan Edwards scenario, and the Dynegy-Vistra scenario. For each scenario we ran the ReEDS model for the contiguous United States, with a consistent set of assumptions across all states. Our analysis then narrowed its focus to the impacts on Illinois.

The pre-FEJA baseline scenario includes:

- State and federal policies in place as of February 2018, and the assumption that no additional policies have been or will be implemented. It assumes that FEJA was not implemented in Illinois in 2016—we modeled Illinois with a broken RPS, efficiency savings limited by rate caps to 1.1 percent per year, and the early retirement of the Quad Cities and Clinton nuclear plants.
- The electricity demand, natural gas prices, and coal prices from the reference case of the AEO 2018.
- State energy-efficiency standards through December 2017, as calculated by our team (based on data from state utilities and from the Database of State Incentives for Renewables and Efficiency) using a methodology developed by the EPA for state analyses.
- State renewable energy standards, as established through July 2017 based on information calculated by Lawrence Berkeley National Laboratory or NREL as part of ReEDS assumptions.
- The model revisions described in the previous section.

The FEJA scenario includes:

- The same elements as the pre-FEJA baseline scenario, with all of the FEJA policies, including the Illinois RPS, EEPS, and new build requirements for wind and solar, and the continued operation of the Quad Cities and Clinton nuclear power plants that received temporary financial support under the law.

The Waukegan-Edwards scenario includes:

- The same elements as the FEJA scenario, and layers on additional coal retirements according to the schedule in Table TA-4 and Table TA-5. These retirement dates were selected based on conversations with stakeholders, including external reviewers from the Environmental Law and Policy Center and the Natural Resources Defense Council.

The Dynegy-Vistra scenario includes:

- The same elements as the FEJA scenario, and layers on additional coal retirements according to the schedule in Table TA-4 and Table TA-5. These retirement dates were selected based on conversations with stakeholders, including external reviewers from the Environmental Law and Policy Center and the Natural Resources Defense Council.

TableTA-5. **Prescribed Retirement Dates for All Cases**

		Database	Scenarios					
Plants		Lifetime of Plant	Pre-FEJA Baseline	FEJA	Waukegan Edwards	Dynegy-Vistra	Forced Retirement Date Scenario	Forced Retirement Date
Waukegan	Unit 7	2034	2034	2034	2020	2034	Waukegan Edwards scenario	2020
	Unit 8	2038	2038	2038	2022	2038		2022
Edwards	Unit 2	2044	2030	2022	2020	2020	Waukegan Edwards, and Dynegy-Vistra Scenarios	2020
	Unit 3	2048	2030	2022	2022	2022		2022
Coffeen	Unit 1	2040	2040	2040	2040	2024	Dynegy-Vistra scenario	2024
	Unit 2	2048	2048	2048	2048	2026		2026
Baldwin	Unit 1	2020	2020	2020	2020	2020	All scenarios	2020
	Unit 2	2020	2020	2020	2020	2020		2020
Havana	Unit 6	2054	2022	2022	2022	2026	Dynegy-Vistra scenario	2026
Joppa	Unit 1	2028	2028	2028	2028	2020	Dynegy-Vistra scenario	2020
	Unit 2	2028	2028	2028	2028	2022		2022
	Unit 3	2030	2030	2028	2028	2022		2022
	Unit 4	2030	2030	2030	2030	2024		2024
	Unit 5	2030	2030	2030	2030	2024		2024
	Unit 6	2030	2030	2030	2030	2026		2026
Newton	Unit 1	2052	2052	2052	2052	2030	Dynegy-Vistra scenario	2030
Duck Creek	Unit 1	2052	2052	2052	2052	2030	Dynegy-Vistra scenario	2030
Hennepin	Unit 1	2020	2020	2020	2020	2020	Waukegan Edwards, and Dynegy-Vistra scenarios	2020
	Unit 2	2034	2034	2030	2030	2030		2030

TABLE TA-6. **Comparison of Overnight Capital Costs for Electric Generation Technologies**

Technology	Overnight Capital Costs (2017$/kW)				
	2010	2020	2030	2040	2050
Natural gas, combined cycle	1,054	1,047	1,000	965	926
Natural gas, combined cycle / carbon capture and storage	N/A	2,165	1,988	1,845	1,695
Natural gas, combustion turbine	895	895	851	820	785
Coal, supercritical pulverized coal	3,186	3,699	3,570	3,478	3,359
Coal, integrated gasification and combined cycle	4,109	3,966	3,713	3,543	3,357
Coal, pulverized coal / carbon capture and storage	7,109	5,677	5,370	5,121	4,833
Nuclear	5,195	5,721	5,527	5,229	4,829
Hydro*					
Biomass, dedicated	4,466	3,873	3,656	3,511	3,339
Biomass, cofired with coal**	2,989	2,989	2,989	2,989	2,989
Solar, utility-scale PV	4,617	1,130	940	836	741
Solar, residential PV	6,981	2,544	1,551	1,293	1,189
Solar, commercial PV	3,488	1,877	1,149	1,045	993
Solar, concentrating solar power plant with s-x hour storage	9,767	6,945	6,174	5,643	5,352
Wind, onshore (class 3)	1,920	1,488	1,404	1,415	1,377
Wind, onshore (class 4)	1,920	1,500	1,344	1,336	1,290
Wind, onshore (class 5)	1,488	1,323	1,404	1,311	1,262
Wind, onshore (class 6)	1,779	1,469	1,290	1,268	1,214
Wind, onshore (class 7)	1,635	1,448	1,267	1,243	1,189
Wind, shallow offshore	5,640	4,811	4,093	3,982	3,856
Wind, deep offshore	6,228	5,311	4,516	4,393	4,254
Landfill gas	9,288	8,765	8,542	8,323	8,039

Notes: *Hydro capital costs are too detailed to show in this table; ReEDs uses supply curves with capital cost variation by potential resource capacity.
**The cost for biomass co-firing is per kW of biomass capacity.

TABLE TA-7. **Operation and Maintenance (O&M) and Heat Rate Assumptions**

Technology	Fixed O&M ($2017/kW-yr)	Variable O&M ($2017/MWh)	Heat Rate (Btu/kWh)	
			2020	2050
Natural gas, combined cycle	10.6	2.8	6,624	6,275
Natural gas, combined cycle / carbon capture and storage	33.8	7.2	7,504	7,493
Natural gas, combustion turbine	12.3	7.2	9,756	9,075
Coal, supercritical pulverized coal	33.2	4.8	8,760	8,740
Coal, integrated gasification and combined cycle	54.1	7.6	7,867	7,450
Coal, pulverized coal / carbon capture and storage	70.0	4.7	9,105	9,316
Nuclear	101.3	2.3	10,479	10,460
Biomass	112.2	5.6	13,500	13,500
Solar PV-utility	13.4	0.0	n/a	n/a
Solar CSP-With Storage	68.3	0.0	n/a	n/a
Wind-Onshore	52.5	0.0	n/a	n/a
Wind-Shallow Offshore	136.5	0.0	n/a	n/a

Note: Fixed and variable O&M costs are for 2020 through 2050; costs for earlier years are higher.

TABLE TA-8. **Solar Capacity Factors**

Technology	Capacity Factor
Utility-scale solar PV	14-28%
Concentrating solar plant with six-hour storage	28-38%

TABLE TA-9. **Comparison of Wind Capacity Factors**

Technology	Capacity Factor				
	2014	2020	2030	2040	2050
Wind, onshore class 3	32.0%	34.5%	37.0%	38.3%	39.6%
Wind, onshore class 4	37.7%	40.7%	43.6%	45.1%	46.7%
Wind, onshore class 5	43.9%	46.5%	49.2%	50.8%	52.5%
Wind, onshore class 6	46.6%	49.0%	51.5%	53.2%	54.9%
Wind, onshore class 7	51.1%	53.7%	56.4%	58.2%	60.1%
Wind, offshore class 4	34.6%	35.3%	37.9%	38.3%	38.8%
Wind, offshore class 5	40.3%	41.2%	44.1%	44.7%	45.2%
Wind, offshore class 6	43.2%	44.2%	47.3%	47.9%	48.4%
Wind, offshore class 7	47.3%	48.4%	51.8%	52.4%	53.0%

HOMER

UCS employed the HOMER (Hybrid Optimization of Multiple Energy Resources) Pro Version 3.11—an energy system optimization and financial analysis model specifically designed to analyze distributed generation and microgrids at the customer and local levels—to analyze the economic feasibility of installing utility-scale storage at the Waukegan plant site and surrounding area, as well as investing in behind-the-meter storage combined with solar and energy efficiency at homes and businesses in Waukegan.

METHODOLOGY

HOMER Pro was originally developed by NREL and is now distributed by HOMER Energy LLC as a proprietary computer software package. HOMER Pro models a power system's physical operations and its life-cycle cost, the total cost of installing and operating the system over its lifespan. HOMER allows users to compare many different system options based on their technical and economic benefits. Users may design any combination of electrical generation and storage technologies with and without grid connection. HOMER Pro has two optimization algorithms. The original grid search algorithm simulates all of the feasible system configurations with a proprietary derivative-free algorithm to search for the least-costly system, and then displays a list of configurations sorted by net present cost that can be used to compare system design options (HOMER Energy 2018; Lambert, Gilman, and Lilienthal 2006).

ASSUMPTIONS UNDERLYING THE HOMER ANALYSIS

FINANCIAL

Our financial analysis assumed that the investments are made in 2021 and the projects have a 25-year lifetime. All of the net-present-value calculations in the HOMER analysis used a real discount rate of 6.2 percent.

DEMAND

- **Utility-scale analysis.** UCS used ComED's metered load data posted in January 2017 on the PJM website.[2] The load data were scaled down to 2,000 MW in order to simulate a portion of ComED's service territory which could possibly have a power shortage issue in the unlikely event that both transmission lines and the combustion turbine peaker plant were offline during the hottest day of the year.
- **Behind-the-meter analysis.** The OpenEI database provides the commercial and residential hourly load profiles for all typical meteorological year 3 (TMY3) locations in the United States (DOE 2014). It contains hourly load profile data for 16 commercial building types and residential buildings based on the Department of Energy commercial reference building models and the Building America house simulation protocols. We modeled three building types; two types of commercial buildings (secondary school and supermarket) and a typical single-family home in Waukegan.

POLICY ASSUMPTIONS

- The **solar investment tax credit** is currently a 30 percent federal tax credit claimed against the tax liability of residential and commercial investors in solar energy property. It is scheduled to ramp down to 26 percent for projects that begin construction in 2020, and 22 percent in 2021. After 2021, it will drop to zero for residential projects, while for commercial and utility projects it will drop to a permanent 10 percent. Since this analysis assumes that the investments are made in 2021, an investment tax credit of 22 percent is applied to the initial investment cost estimation.
- **Solar renewable energy credits (SRECs)** are tradable credits that represent the clean energy benefits of electricity generated from a solar energy system. Each time a solar system generates 1,000 kWh of electricity, an SREC is issued, which can be sold or traded. In Illinois, block pricing is applicable to two project types: PV distributed renewable energy generation and PV community renewable generation. We used block group REC prices ($/REC) presented in the Illinois Power Agency's Long-Term Renewable Resources Procurement Plan (LTRRP) released on December 4, 2017 (IPA 2017). Block 2 in group B was used for the economics calculation for behind-the-meter customers. See Table TA-10.

The Illinois Power Agency released its final Long-Term Renewable Resources Procurement Plan on August 6, 2018. Our analysis does not reflect the updated Block Group REC prices presented in the final plan.

- **Net metering.** Under ComED's service territory, net metering is available for residential and commercial customers who generate up to 2,000 kW. The availability of net metering for ComED customers was included in the behind-the-meter system designs.

TECHNOLOGY COST AND PERFORMANCE

The cost and performance assumptions for electricity-generating and storage technologies that we made in using the HOMER modeling are shown in Tables TA-11 through TA-14 below.

- **Solar PV.** The cost assumptions were based on NREL's *Annual Technology Baseline 2017*, mid-case. UCS adjusted the cost reflecting the solar tariffs announced in 2017 and the federal investment tax credit (at 22 percent in 2021).
- **Storage.** For utility-scale analysis, UCS assumed a four-hour lithium-ion battery storage system under a peaking plant replacement use case from Lazard (Lazard 2017). We used the price and performance of Tesla Powerwall 2.0 (lithium-ion battery) for the behind-the-meter storage application. We applied 22 percent of federal investment tax credit to the capital cost estimation. Based on Lazard's storage price outlook, we assumed that the storage cost would decrease by 10 percent annually (Lazard 2017).
- **Natural gas combustion turbine.** To compare the life-cycle cost of replacing a natural gas combustion turbine with (1) a renewable option, or (2) another natural gas combustion turbine, we conducted additional HOMER modeling. Consistent with our solar PV assumptions, we used NREL's Annual Technology Baseline 2017 mid-case for cost and performance assumptions. The natural gas price (delivered to the power sector) assumption came from the EIA's AEO 2018 reference case for the East North Central census division.

ELECTRICITY PRICE FOR THE BEHIND-THE-METER ANALYSIS

Annual-averaged retail prices under ComED's Basic Electric Service tariff were used for the behind-the-meter analysis: 10 cents per kWh for commercial customers and 13 cents per kWh for residential customers.

ENERGY EFFICIENCY

- **Utility-scale analysis**. UCS assumed that an annual incremental savings target of 1.98 percent (10.7 years of measure time) could be realized under FEJA in ComED's service territory.
- **Behind-the-meter analysis.** The energy efficiency options and their expected percentage savings for commercial buildings came from ICF's ComED Energy Efficiency Potential Study (2017–2030) (ICF 2016). The average savings from energy efficiency (%) of a typical Illinois single-family house came from NREL's report Energy Efficiency Potential in the US Single-Family Housing Stock (NREL 2017b).

TABLE TA-10. **Block Group REC Prices ($/REC) Presented in the Illinois Power Agency's Long-Term Renewable Resources Procurement Plan**

Block Group	Block Category		Block 1	Block 2	Block 3
Group A (Ameren Illinois, MidAmerican, Mt. Caramel, Rural Electric Cooperatives, and Municipal Utilities located in MISO)	Small	<= 10kW	$82.48	$79.18	$76.02
	Large	> 10 – 25 kW	$74.75	$71.76	$68.89
		> 25 – 100 kW	$58.51	$56.17	$53.92
		> 100 – 200 kW	$45.75	$43.92	$42.16
		> 200 – 500 kW	$39.87	$38.27	$36.74
		> 500 – 2,000 kW	$37.57	$36.07	$34.63
	Community Solar	<= 10kW	$111.44	$106.98	$102.70
		> 10 – 25 kW	$99.88	$95.88	$92.05
		> 25 – 100 kW	$79.17	$76.00	$72.96
		> 100 – 200 kW	$65.76	$63.13	$60.61
		> 200 – 500 kW	$59.55	$57.17	$54.88
		> 500 – 2,000 kW	$56.93	$54.66	$52.47
Group B (ComEd, and Rural Electric Cooperatives and Municipal Utilities located in PJM)	Small	<= 10kW	$74.03	$71.07	$68.23
	Large	> 10 – 25 kW	$67.58	$64.88	$62.28
		> 25 – 100 kW	$52.62	$50.52	$48.50
		> 100 – 200 kW	$39.87	$38.27	$36.74
		> 200 – 500 kW	$33.98	$32.62	$31.32
		> 500 – 2,000 kW	$31.69	$30.42	$29.21
	Community Solar	<= 10kW	$105.79	$101.56	$97.50
		> 10 – 25 kW	$94.24	$90.47	$86.85
		> 25 – 100 kW	$73.52	$70.58	$67.76
		> 100 – 200 kW	$60.12	$57.71	$55.40
		> 200 – 500 kW	$53.91	$51.75	$49.68
		> 500 – 2,000 kW	$51.29	$49.24	$47.27

SOURCE: IPA. 2017

TABLE TA-11: **Solar PV Costs in 2021**

	Utility	Commercial	Residential
Capital cost (2017$/kW)	856	1,396	1,896
O&M cost (2017$/kW/year)	11.6	12.3	16.3

TABLE TA-12: **Storage Cost and Performance in 2021**

	Utility-scale Storage for Peaker Plant Replacement	Behind-the-Meter Storage
Battery technology specification	1 MWh 250 kW lithium-ion, 4-hour duration	Tesla Powerwall 2.0 (13.2 kWh), 2-hr duration
Capital cost (2017$)	223,638	3,326
O&M cost (2017$/year)	1,806	
Lifetime (years)	20	10
Lifetime throughput (kWh)	7,000,000	67,500

TABLE TA-13: **Natural Gas Combustion Turbine Cost and Performance in 2021**

	Natural Gas Combustion Turbine (7% Capacity Factor)
Capital cost (2017$/kW)	904
Fixed O&M cost (2017$/kW/year)	12.2
Variable O&M cost (2017$/MWh)	7.2
Natural gas price delivered to the power sector (2017$/Mcf) (Mcf is the volume of 1,000 cubic feet)	3.99

TABLE TA-14: **Energy Efficiency Assumptions for the Behind-the-Meter Analysis**

Sector	Building Type	Energy Efficiency Option	Energy Efficiency savings (%)	Lifetime (years)
Commercial	Secondary school	Non-lighting project	19	15
	Supermarket	LED bulb and fixtures	17	4
Residential	Single-family house	IL typical energy-efficiency adoption for residential buildings	19	11

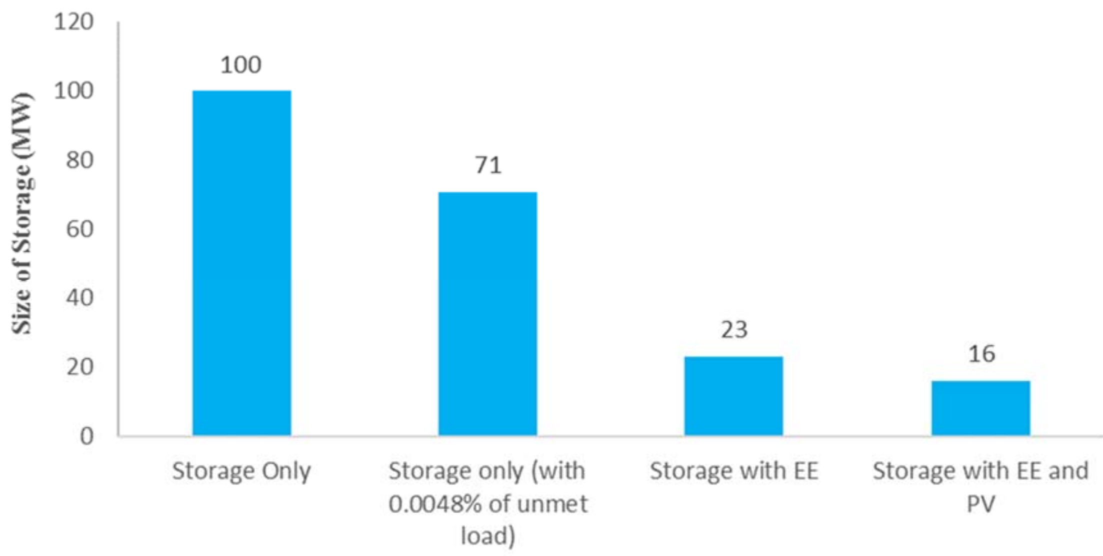
SOURCES: NREL 2017B; ICF 2016

Analysis of Options for Replacing Natural Gas Peaker Plant with Clean Energy

UCS measured the required size of storage as a replacement option for the existing combustion-turbines at the Waukegan site. As shown below, the size of storage needed varies depending on the combination of technologies and the system design features. Figure TA-1 shows the size of storage by option.

- **Storage only** (with 0 percent of unmet load): A storage system without any unmet load. When the size of storage is set to be exactly 100 MW, the unmet load becomes 0 percent.

FIGURE TA-1 **Size of Storage for Peaker Replacement**



- **Storage only (with 0.0048% of unmet load)**: The HOMER model found 71 MW of storage as an optimal solution with an allowance of 0.0048 percent of unmet electric load. Since adding 29 MW to serve 0.0048 percent of unmet load is cost-inefficient, the model presented 71 MW as the final optimal solution.
- **Storage with energy efficiency**: Assuming ComEd meets its energy efficiency targets required under FEJA, 23 MW of storage would be needed.
- **Storage with energy efficiency and PV**: If efficiency investments are combined with solar deployment required under FEJA, and the solar facilities in the surrounding area could cover 5 percent of the load, only 17 MW of storage would be needed.

LAND SIZE ESTIMATION

We roughly estimated the size of land required for the 16 MW of storage based on the similar-scale project that Greensmith installed for Pomona energy storage facility in 2016, a 20 MW storage plant built in Aliso Canyon in California.

Clean Air Task Force Analysis

UCS partnered with the Clean Air Task Force (CATF) to conduct a public health impact analysis using data provided from CATF's Powerplant Impact Estimator software tool. This tool calculates the impact of SO2, NOx, and directly emitted particulate matter pollution on ambient air quality levels and applies health impact functions to the attributable increment of pollution (i.e., the estimated change in the incidence of a particular health effect for a given increment of air pollution). The tool then estimates the contribution of the plants' emission(s) to ambient PM2.5 levels in each county in the continental United States and the associated attributable incidence of various adverse health effects in each county.

CATF provided data on the public health impacts of Illinois coal plants. For a given year of operations, CATF estimated for each plant the incidents caused in numerous health categories. Using these data, we were able to discern how retiring coal plants and replacing them with clean energy improves public health by avoiding impacts from those plants in the future (Tables TA-15, TA-16, and TA-17).

For the purposes of simplifying the analysis, we began our calculation of avoided health impacts in the year the plants are fully retired in the scenario (i.e., 2022). This has the effect of undercounting the public health benefits from the retirement of Edwards Unit 2 and Waukegan Unit 7 because the calculation does not include avoided health impacts during the two years the scenario retires those units (i.e., in 2020) prior to full closure of the plants in 2022. Accordingly, the numbers we are presenting here are conservative.

It is important to note, as with the Waukegan-Edwards scenario discussed above, we began our calculation of avoided health impacts for the year that the plants are fully retired by the scenario. In addition, because CATF reports health impact data at the plant level, we assigned to the Hennepin and Joppa units in Table TA-18 a percentage of the plants' total public health impact to those units in proportion to the units' percentage of the plants' MWh generated in 2016.

TABLE TA-15: **Health Impacts Avoided from Retirement of Crawford, Fisk, and Wood River Plants**

Coal Plant	Year Retired	Avoided Health Impacts Compared to Plants Operating Through 2030				
		Avoided Premature Deaths	Avoided Heart Attacks	Avoided Asthma ER Visits	Avoided Hospital Admissions	Avoided Chronic Bronchitis
Crawford	2012	748	459	306	204	187
Fisk	2012	459	289	187	136	119
Wood River	2016	733	438	304	205	174
Total		1,940	1,186	797	545	480

Note: 2010 health impact data were utilized for Crawford and Fisk, and 2012 data were used for Wood River.

TABLE TA-16: **Cumulative Impacts Avoided by Early Retirement of Edwards and Waukegan**

Coal Plant	Unit Codes	Year Fully Retired	Cumulative Health Impacts Avoided by Pre-2030 Retirement of Waukegan and Edwards Plants Compared to Plants Operating at 2016 Levels Through 2030				
			Premature Deaths	Heart Attacks	Asthma ER Visits	Hospital Admissions	Chronic Bronchitis
Edwards	2, 3	2022	288	175	120	82	70
Waukegan	7, 8	2022	143	89	58	42	34
Total			431	264	178	124	104

TABLE TA-17: **Cumulative Health Impacts Avoided Through Pre-2030 Retirement of Dynegy's MISO Coal Plants in Illinois**

Plant	Unit Code(s)	Year Fully Retired	Cumulative Health Impacts Avoided Through Pre-2030 Retirement Compared to Plants Operating Through 2030				
			Premature Deaths	Heart Attacks	Asthma ER Visits	Hospital Admissions	Chronic Bronchitis
Baldwin	1, 2, 3	2020	261	157	110	73	62
Coffeen	1, 2	2026	18	10	8	5	4
Edwards	2, 3	2022	288	175	120	82	70
Havana	6	2022	74	45	31	21	42
Hennepin	1	2020	64	39	27	18	16
Joppa	1	2020	84	50	34	24	20
Joppa	2	2022	66	39	26	18	15
Joppa	3	2022	38	23	15	11	9
Joppa	4	2024	46	27	19	13	11
Joppa	5	2024	26	15	10	7	6
Joppa	6	2026	21	12	8	6	5
Total			986	592	408	278	260

TABLE TA-18: **Illinois Coal Plants Modeled in the Pre-FEJA Baseline**

Plant	Unit Code	Operating Through
Baldwin	1	2020
Baldwin	2	2020
Coffeen	1	Beyond 2030
Coffeen	2	Beyond 2030
Duck Creek	1	Beyond 2030
Edwards	2	2030
Edwards	3	2030
Havana	6	2022
Hennepin	1	2020
Hennepin	2	Beyond 2030
Joppa	1	2028
Joppa	2	2028
Joppa	3	2030
Joppa	4	2030
Joppa	5	2030
Joppa	6	2030
Newton	1	Beyond 2030
Waukegan	7	Beyond 2030
Waukegan	8	Beyond 2030

University of Wisconsin Analysis

UCS partnered with students from the University of Wisconsin - Madison, Nelson Institute for Environmental Studies, Department of Environment and Resources, in 2017. Four graduate students of the program, under the direction of Professor Bernie Lesieutre, completed a report for UCS titled Analyzing the Economic, Environmental and Equity Impacts of Replacing Coal Plants with Clean Energy and Storage in Illinois (Flores et al. 2017). The report discussed their analysis of the economic, environmental, and equity impacts of replacing coal plants in Illinois with clean energy technologies and storage. The analysis included three steps: 1) identifying and ranking coal power plants located in close proximity to vulnerable communities using demographic and environmental data from the EPA’s environmental justice screening tool (EJSCREEN) and health data from the

American Community Survey; 2) quantifying and ranking CO2, SO2, and NOx emissions from coal plants in Illinois using recent data from the EPA and EIA; 3) choosing a coal plant with a high vulnerability ranking to serve as a case study for analyzing the costs and benefits of retiring and replacing the plant with solar and wind power combined with energy storage versus with a new natural gas plant.

The EPA's EJSCREEN was used to generate a report for each area within a three-mile radius of an operating or retired coal power plant in Illinois. EJSCREEN includes demographic indicators such as the percentage of the population that is low income or minority, and environmental indicators such as air quality and proximity to traffic or superfund sites.

Table TA-19 displays statewide percentiles for demographic and environmental indicators generated by EJSCREEN. An asterisk indicates a retired plant. The populations of the communities in the three-mile radius buffer around operating and retired Illinois coal plants are given in the second column. Percentiles ranging from 80 to 90 are shown in yellow, from 90 to 9d4 in orange, and from 95 to 100 in red.

Table TA-20 shows statewide percentiles for environmental indicators in the three-mile radius buffer around operating and retired Illinois coal plants. The demographic indicators are taken from EJSCREEN and health indicators from the American Community Survey (Flores et al. 2017).

Table TA-21 shows EJ Index statewide percentiles for the three-mile radius buffer around operating and retired coal plants in Illinois. The EJ index is a weighting of an environmental indicator by the additional susceptible people in the block group (Flores et al. 2017). An asterisk indicates a retired plant. The buffer areas, in order of decreasing population, are given in the second column. Percentiles ranging from 80 to 90 are shown in yellow, from 90 to 94 in orange, and from 95 to 100 in red.

The EJ Index and the Cumulative Vulnerability Index (CVI) provide different definitions of vulnerability. In the EJ Index, vulnerability is determined by demographic information; while environmental indicators represent potential exposure with each environmental indicator being weighted by demographic information (EPA 2016). The CVI treats demographic and environmental indicators as equally weighted separate groups that each contribute to vulnerability.

The CVI is a method for combining demographic and environmental information. The CVI aggregates the demographic and environmental indicator percentiles from EJSCREEN and supplements them with an aggregate of several health indicator percentiles including low-birthweight births, disability, cancer prevalence, and number of uninsured adults. The percentiles within each group demographic, health indicators, and environmental indicators were averaged, and the averages of the indicators then added together. The groups of indicators are treated equally. For instance, the burdens from environmental pollution are given the same weight as the susceptibility suggested by demographics.

TABLE TA-19. **Statewide Percentiles of Demographic and Health Indicators**

Facility	Population (3mi radius)	Demographic Indicator Statewide Percentiles						Health Indicator BG Percentiles	
		Minority	Low Income	Ling. Isolated	Less than High School	Under 5	Over 64	Disability	Uninsured
Crawford*	344,258	88	87	93	95	73	25	37	94
Waukegan	61,758	82	80	84	89	66	34	48	91
Fisk*	320,314	80	77	84	82	53	31	40	75
Wood River*	27,465	32	72	44	60	40	69	70	63
Hennepin	2,194	74	78	81	90	56	49	57	78
Dallman	32,004	57	68	44	52	62	48	74	51
Lakeside*	30,124	57	68	44	53	61	48	74	51
Will County	33,185	54	41	65	63	45	43	57	52
Havana	3,796	9	72	44	69	29	88	93	47
Joppa Steam	1,157	24	68	44	69	63	60	72	65
Powerton	16,190	20	67	44	58	40	61	75	48
Grand Tower*	639	4	80	44	84	32	89	86	65
Meredosia*	1,286	6	73	44	69	75	69	76	52
E D Edwards	25,066	10	58	44	53	63	62	71	49
Baldwin	605	14	52	44	70	57	59	94	41
Coffeen	788	36	69	44	77	30	73	61	54
Kincaid	598	24	64	44	65	46	85	59	48
Pearl Station*	257	9	67	44	76	58	57	69	59
Marion	2,929	22	44	44	52	14	93	77	28
Hutsonville*	1,015	16	46	44	58	50	73	74	33
Duck Creek	199	9	65	44	53	34	84	86	42
Newton	317	1	42	44	42	90	44	76	34
Prairie State	335	2	38	44	46	41	70	47	32
Vermillion*	967	7	42	44	43	39	65	52	9

Notes: *Facility is retired.

SOURCE: FLORES ET AL. 2017

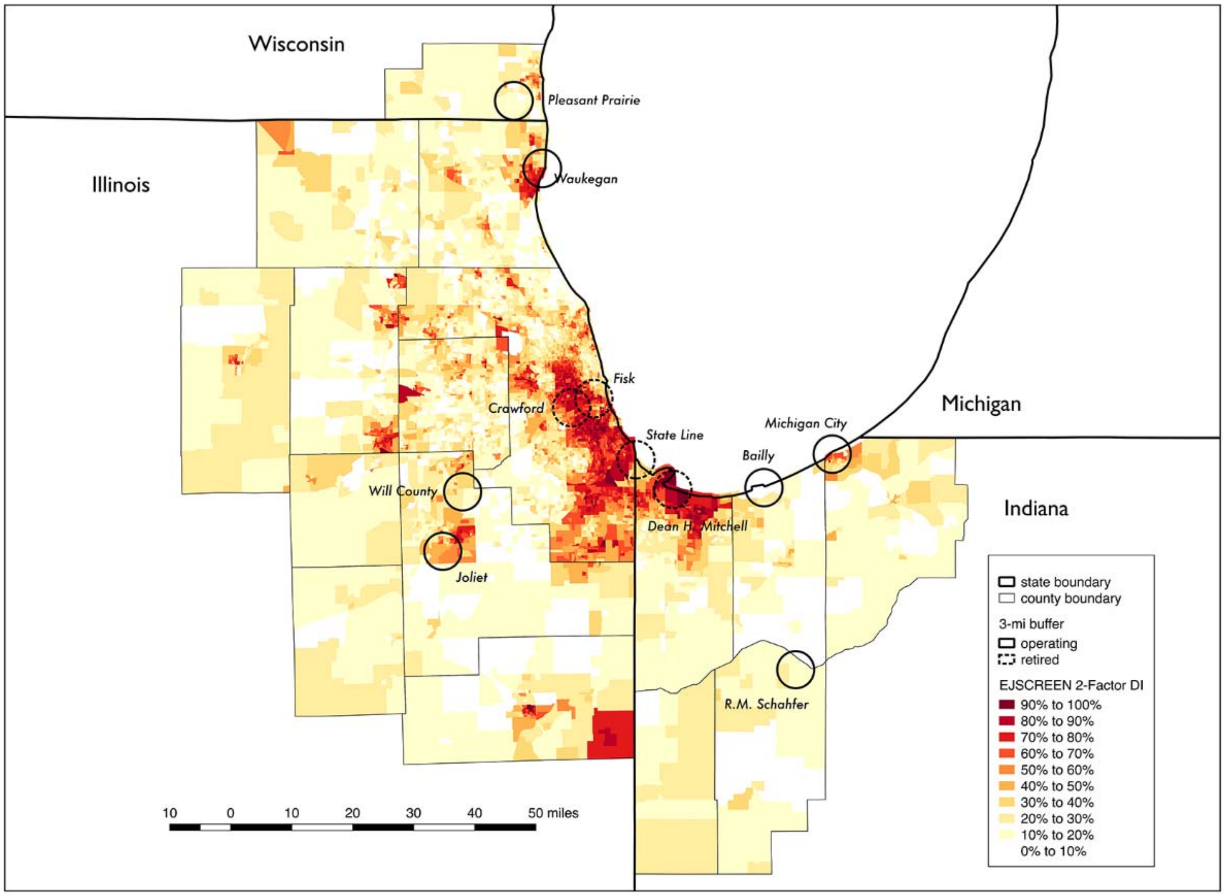
TABLE TA-20. **Statewide Percentiles of Environmental Indicators**

Facility	Environmental Indicator Statewide Percentiles										
	PM 2.5	Ozone	NATA Diesel PM	NATA Cancer Risk	NATA Resp Hazard	Lead Paint	Proximity				
							Traffic	NPL	RMP	TSDF	Water Discharger
Crawford*	97	16	82	78	80	86	78	46	95	91	62
Waukegan	23	85	43	36	36	60	54	99	68	15	86
Fisk*	90	22	95	96	87	58	96	44	95	93	19
Wood River*	41	99	31	92	46	79	58	95	66	12	98
Hennepin	18	64	7	2	2	73	1	99	23	N/A	68
Dallman	15	87	38	51	31	54	66	15	73	N/A	79
Lakeside*	15	87	37	50	30	54	65	15	74	N/A	79
Will County	62	73	49	29	40	35	61	66	83	94	94
Havana	5	74	18	30	13	65	50	7	81	0	71
Joppa Steam	1	99	6	45	14	37	0	78	23	75	74
Powerton	29	49	36	45	27	70	60	7	81	31	96
Grand Tower*	3	95	8	42	11	45	2	14	7	31	61
Meredosia*	0	82	2	17	3	52	29	7	95	0	93
E D Edwards	31	40	33	46	27	65	62	7	79	41	94
Baldwin	7	92	5	41	11	50	41	7	49	0	62
Coffeen	5	91	5	15	5	44	16	91	44	N/A	63
Kincaid	8	88	6	14	5	48	17	59	62	N/A	56
Pearl Station*	0	86	6	25	4	62	4	7	60	0	5
Marion	1	99	0	39	11	24	17	82	45	45	69
Hutsonville*	22	88	1	19	6	57	15	22	48	59	68
Duck Creek	7	59	1	7	1	60	32	7	19	6	32
Newton	10	90	1	12	3	36	0	7	13	1	51
Prairie State	7	94	6	31	10	32	10	11	61	0	3
Vermillion*	15	55	6	4	3	46	39	70	31	3	8

Notes: *Facility is retired.

SOURCE: FLORES ET AL. 2017

FIGURE TA-2: **EJSCREEN Two-Factor Demographic Index for Chicago Metro Block Groups**



SOURCE: FLORES ET AL. 2017

TABLE TA-21. **Statewide Percentiles of Environmental Indicators**

Facility	2-Factor EJ Index (Enviromental and Demographic Information) Statewide Percentiles										
	PM 2.5	Ozone	NATA Diesel PM	NATA Cancer Risk	NATA Resp Hazard	Lead Paint	Proximity				
							Traffic	NPL	RMP	TSDF	Water Discharger
Crawford*	95	94	95	95	95	95	93	88	98	96	92
Waukegan	85	88	82	85	81	86	83	99	87	73	97
Fisk*	87	86	90	86	86	84	93	82	96	95	79
Hennepin	71	71	66	69	66	77	60	98	67	N/A	78
Lakeside*	62	62	67	64	65	71	38	55	60	N/A	69
Dallman	62	62	67	64	65	71	37	55	60	N/A	68
Coffeen	57	56	60	58	59	45	57	35	54	N/A	48
Grand Tower*	53	50	58	52	55	37	61	51	58	50	47
Kincaid	53	51	58	54	57	37	54	41	36	N/A	45
Duck Creek	46	45	56	49	55	22	46	63	52	52	45
Havana	54	53	55	54	56	33	41	63	25	60	41
Joppa Steam	51	47	57	49	53	41	61	30	52	28	31
Newton	35	32	51	38	48	31	61	63	48	55	33
Pearl Station*	42	39	52	42	50	16	58	63	24	58	52
Baldwin	46	42	54	44	50	29	38	55	35	58	36
Prairie State	40	35	51	39	47	38	54	45	22	58	54
Wood River*	54	53	53	51	51	31	33	14	38	54	16
Hutsonville*	36	33	52	38	47	24	53	41	32	21	26
Meredosia*	45	42	54	45	53	25	46	56	4	60	11
Will County	45	47	38	48	43	40	25	33	19	7	13
Vermillion*	30	29	46	36	45	18	34	19	37	47	45
Powerton	42	43	38	41	43	17	28	63	14	41	9
Marion	31	24	49	28	40	41	52	16	25	28	19
E D Edwards	30	30	32	29	34	9	22	63	9	29	7

Notes: *Facility is retired.

SOURCE: FLORES ET AL. 2017

LAND AVAILABILITY ASSESSMENT

We conducted a land availability analysis of the Crawford, Edwards, Fisk, Waukegan, and Wood River sites in order to determine the amount of land available to develop solar and storage on the coal plant sites. The plant locations were first identified using the satellite view in Google Maps. We then used a Google Maps area calculator tool to mark the boundaries of the sites, including any apparent coal ash disposal areas, which generated the total area of each site in square feet. We selected assumptions for the space required per MW of storage and solar by researching the amount of land occupied by real-world projects. For storage, we used as a reference point the Pomona Energy Storage Facility in California, developed by AltaGas and Greensmith Energy.3 The facility is a 20 MW, 80 MWh (four-hour duration) lithium-ion battery installation that occupies 10,800 square feet (540 square feet per MW). For solar, we used as a reference point Exelon's City Solar facility in Chicago, an 8 MW (alternating current (AC)) system that occupies a direct area of about 40 acres (five acres or 217,800 square feet per MW).4 Assuming 540 square feet per MW of storage and 217,800 square feet per MW of solar, we calculated the percentage of the area of the coal plant sites that would be required for a 10 MW project of each technology, as well as calculated the total solar potential of each site.

PowerGEM

UCS retained PowerGEM, an engineering firm with experience preparing reliability studies of the electric grid, to determine whether there are any reliability issues to address for the Chicago and northern Illinois region if all of the existing Waukegan generation were to be retired. In its study, PowerGEM assumed the transmission system as it is expected to be in the summer of 2022 and used the related data files provided by grid operator PJM. PJM studies grid reliability needs at the time of the highest energy use, as this is when reliability issues are most sensitive to a retirement (Gass 2017).

PowerGEM looked at the impact of retiring 783 MW, made up of Waukegan 7 (328 MW coal) which came into service in 1958, Waukegan 8 (354 MW coal) which came into service in 1962, and the Waukegan oil-burning combustion turbines (four operating with a total capacity of 101 MW) which came into service in 1968.

The transmission study replaced this 783 MW with an equal amount of generation spread evenly across the existing power plant locations in the 13 states served by PJM, similar to how PJM studies future retirements of power plants. The results showed that the two coal units could be retired with no impacts on reliability, and that retiring the combustion turbines would require replacement of 100 MW to prevent reliability problems. The PowerGEM study showed that the issue could be resolved either with 100 MW of additional capacity at the Waukegan location or with clean energy options like solar, storage, demand response, efficiency, and other distributed generation located across many cities and towns surrounding downtown Chicago.

FIGURE TA-3: **Land Area Around the Crawford Generating Station**

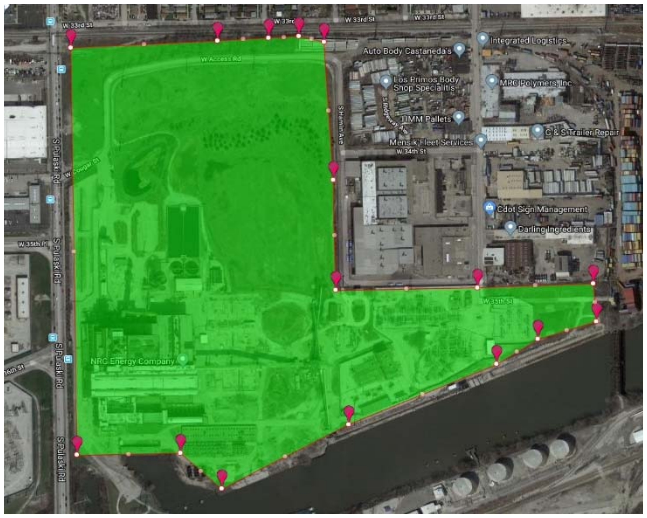


TABLE TA-22: **Total Utilizable Area Around the Crawford Generating Station**

Crawford	
Site area (sq. ft.)	3,000,000
Percentage required for 10 MW, 40 MWh storage	0.18%
Percentage required for 10 MW solar	73%
Solar potential	14 MW AC

FIGURE TA-4: **Land Area Around the Edwards Generating Station**

TABLE TA-23: **Total Utilizable Area Around the Edwards Generating Station**

Edwards	
Site area (sq. ft.)	9,000,000
Percentage required for 10 MW, 40 MWh storage	0.06%
Percentage required for 10 MW solar	24%
Solar potential	41 MW AC

FIGURE TA-5: **Land Area Around the Fisk Generating Station**

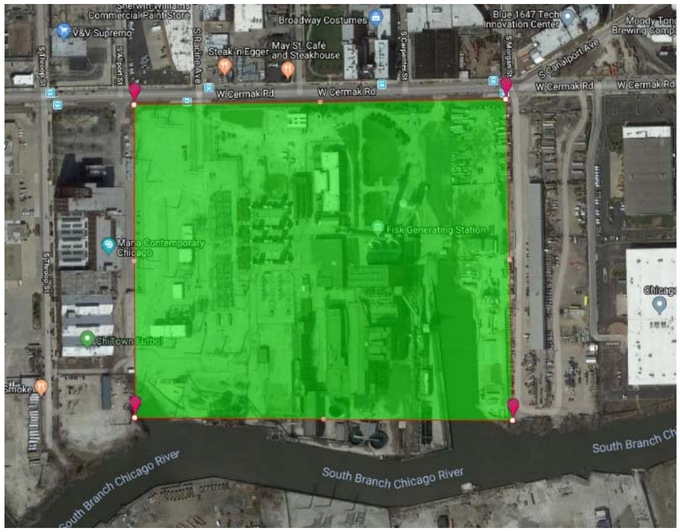


TABLE TA-24: **Total Utilizable Area Around the Fisk Generating Station**

Fisk	
Site area (sq. ft.)	2,000,000
Percentage required for 10 MW, 40 MWh storage	0.27%
Percentage required for 10 MW solar	109%
Solar potential	9 MW AC

FIGURE TA-6: **Land Area Around the Waukegan Generating Station**

TABLE TA-25: **Total Utilizable Area Around the Waukegan Generating Station**

Waukegan	
Site area (sq. ft.)	26,000,000
Percentage required for 10 MW, 40 MWh storage	0.02%
Percentage required for 10 MW solar	8%
Solar potential	119 MW AC

FIGURE TA-7: **Land Area Around the Wood River Generating Station**

TABLE TA-26: **Total Utilizable Area Around the Wood River Generating Station**

Wood River	
Site area (sq. ft.)	10,000,000
Percentage required for 10 MW, 40 MWh storage	0.05%
Percentage required for 10 MW solar	22%
Solar potential	46 MW AC

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