Transition Opportunities for Prairie State Energy Campus

insight brief

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HIGHLIGHTS

- The 1,600 MW Prairie State Energy Campus (PSEC) was built in 2012 at a cost of $5 billion, despite significant concerns about the plant's environmental and economic performance.
- Since construction on PSEC began, the cost of gas and renewable energy has fallen dramatically, resulting in a 33% decrease in US coal production from 2010 to 2019.[1]
- PSEC operation is barely profitable compared with the market now and is unlikely to save money compared with the market in the future.
- Given recent and projected declines in the cost of renewable energy and battery storage, PSEC's go-forward costs will likely be significantly more expensive than alternatives prior to 2030, meaning that customers will save money when PSEC stops operations.
- Refinancing the debt with a ratepayer-backed security could allow plant owners to reinvest in clean energy solutions while saving Illinois ratepayers more than $300 million or the equivalent of more than 0.3¢/kWh ($3/MWh).
- Being proactive and planning for early retirement of PSEC is key to leveraging the opportunities that exist for all stakeholders—plant owners, ratepayers, and the local community—to maximize the upside of plant closure.

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INTRODUCTION

The Prairie State Energy Campus (PSEC) in Illinois—which consists of two 800 MW coal-fired power stations and a coal mine—provides power to 2.5 million families throughout the Midwest and Mid-Atlantic region. When PSEC construction began in 2007, prices of alternative generation such as natural gas and renewable energy were much higher, making it seem like a reasonable investment. When the plant came online in 2012, it cost $900 million more than expected, and the cost of alternative generation had fallen significantly, driving an economy-wide move away from coal.

From 2010 to 2019 competition from natural gas power plants, wind, and solar drove a 33% decline in US coal production. In 2019 alone, the US power sector retired 13,700 MW of coal capacity. In 2020, US coal consumption fell an additional 19% to the lowest since 1905.[i,2] Even without national carbon policy, most independent analysts agree that coal will be a marginal source of US power by 2030.[3]

PSEC is subject to the same competitive pressures as other coal plants. PSEC owners participate in the PJM and MISO regional transmission organizations (RTOs). This means they can purchase real-time energy (MWh) and peak capacity (MW) from competitive markets instead of sourcing it entirely from owned generation. Over the past five years, fueling, operating, and maintaining the plant cost customers slightly more than they would have paid for the same energy and capacity from market purchases—without including PSEC debt-related costs. Taking PSEC debt-related costs into consideration, the plant cost customers much more than equivalent market purchases.

Between now and 2030, market prices for energy are expected to remain low, and the price of energy and services from wind, solar, and battery storage are expected to decline. By 2030, closing PSEC and replacing it with a clean energy portfolio (CEP) that includes wind, solar, battery storage, demand flexibility, and energy efficiency is expected to save ratepayers money without sacrificing reliability (see Appendix D for details).

The proposed Illinois Clean Energy Jobs Act (CEJA) legislation could include a mandate to close PSEC by 2030. While some may argue that plant owners and Illinois ratepayers would be worse off if PSEC were mandated to close before the end of its useful life, the opposite is likely true. Even with little or no proactive action, if Prairie State Energy Campus is closed by 2030, Illinois ratepayers will—at a minimum—not be significantly worse off. And if closure were accompanied by replacement with a clean energy portfolio and supportive state policies, ratepayers and the community could see significant financial and social benefits, particularly if renewables are procured prior to the phase-out of federal tax incentives for solar, wind, and storage.

[i] RMI analysis of EIA data found that 2020 US coal consumption (measured in MMBTU) hit lowest level since 1904.

PLANT DEBT AND OWNERSHIP

PSEC is owned by nine public power agencies—six municipal utility joint power authorities and three cooperative generation and transmission providers—that serve a total of 277 municipal utilities and electric cooperatives (see Appendix B). The plant owners—all nonprofit utilities—signed contracts directly or indirectly committing themselves to paying off the $5 billion price tag to build the campus.

Today, for many of the owners, outstanding debt is higher than the initial cost share of the campus (see Appendix C). The debt may be increasing for two reasons: (1) owners have issued additional debt to finance capital improvements, and (2) owners didn't charge rates that reflected the true costs of operation in the initial years when capacity factors were low, as they assumed the needed revenues would be collected from ratepayers in the future when the plant would run more efficiently. Ratepayers are scheduled to pay interest and principal on PSEC debt through 2041 or beyond.

While ratepayers, plant-owners, and policymakers should evaluate and consider options to relieve the long-term ratepayer impact of PSEC debt (see *Key Policy Options and Opportunities* section below), their decision to continue to operate the plant should be driven by the annual cost to operate the plant compared with equivalent alternatives.

PLANT ECONOMICS

From 2016 to 2019 the total cost to operate PSEC and service debt associated to the plant was more than $3.2 billion—7.2¢/kWh ($72/MWh) considering energy produced. PSEC owners paid $1.4 billion (3.1¢/kWh) for fuel, operations and maintenance (O&M), and capital additions necessary to operate the plant.[ii] PSEC owners also paid an estimated $1.8 billion (4.1 ¢/kWh) on plant interest and principal repayment.[iii] For additional details on PSEC cost, see Appendix A.

[ii] Some operating costs (e.g., property tax) may not be avoidable if a plant is closed. This analysis assumes that unavoidable operating costs were small compared with the total annual cost to operate the plant.

[iii] Based on interest and principal payments from NIMPA net of Build America Bond subsidies.

PSEC operates within the MISO energy market. Approximately 40% of PSEC output is exported (wheeled) to the PJM energy market to serve the needs of PSEC owners in northern Illinois, Ohio, Kentucky, Virginia, and West Virginia.[iv] The plant provides two primary services in each of these markets: 1) energy (measured in kWh or MWh) and 2) capacity, or the ability to meet power during times of peak system-wide demand (measured in kW or MW).[v] Since the PJM and MISO market both have more than enough generation capacity to meet customer needs,[vi] PSEC owner utilities could have in theory shut-down the plant at the start of 2016 and purchased energy and capacity from the MISO and PJM markets.[vii]

Utilities are often disinclined to rely on PJM and MISO capacity markets, and prefer to secure long-term price certainty through long-term capacity agreements. Therefore, instead of relying entirely on annual capacity auctions, owners might have entered into long-term agreements with independent power producers or other utilities to secure long-term capacity services. PJM and MISO define the maximum theoretical value for capacity as CONE (cost of new entry)—the capacity price required to induce development of new generation.

From 2016 to 2019, the total annual cost to operate PSEC was 0.2¢/kWh ($2/MWh) higher than the cost to buy energy and capacity from the PJM and MISO markets. A power plant participating in capacity auctions receives market capacity payments through clearing prices, as determined by the combination of supply and demand. Since annual capacity auctions may underrepresent the true value of capacity in the long term, utilities often consider the cost to build new capacity (the cost to build new capacity including current, annualized capital cost of constructing a power plant) when evaluating plant economics. PSEC operations cost 0.6¢/kWh ($6/MWh) less than market energy plus CONE. When debt-related costs are considered, the costs to operate PSEC were between 2.7¢/kWh ($27/MWh) and 3.5¢/kWh ($35/MWh) higher than energy and capacity purchases (See Exhibit 1).

[iv] Based on PJM disclosures on pseudo-tied units (**https://www.pjm.com/-/media/etools/oasis/special-notices/pjm-miso-pseudo-tied-units-operating-procedure.ashx?la=en**)

[v] PSEC also provides other market services including frequency regulations and spinning reserves. The value of these services is currently small compared with the value of energy and capacity. The value of some of these services may increase over time as more inverter-based generation (i.e., wind and solar) enters the market.

[vi] In 2020, NERC projects that PJM will have 33,300 MW (20%) in excess of required capacity, and that MISO will have 5,200 MW (4%) in excess of required capacity.

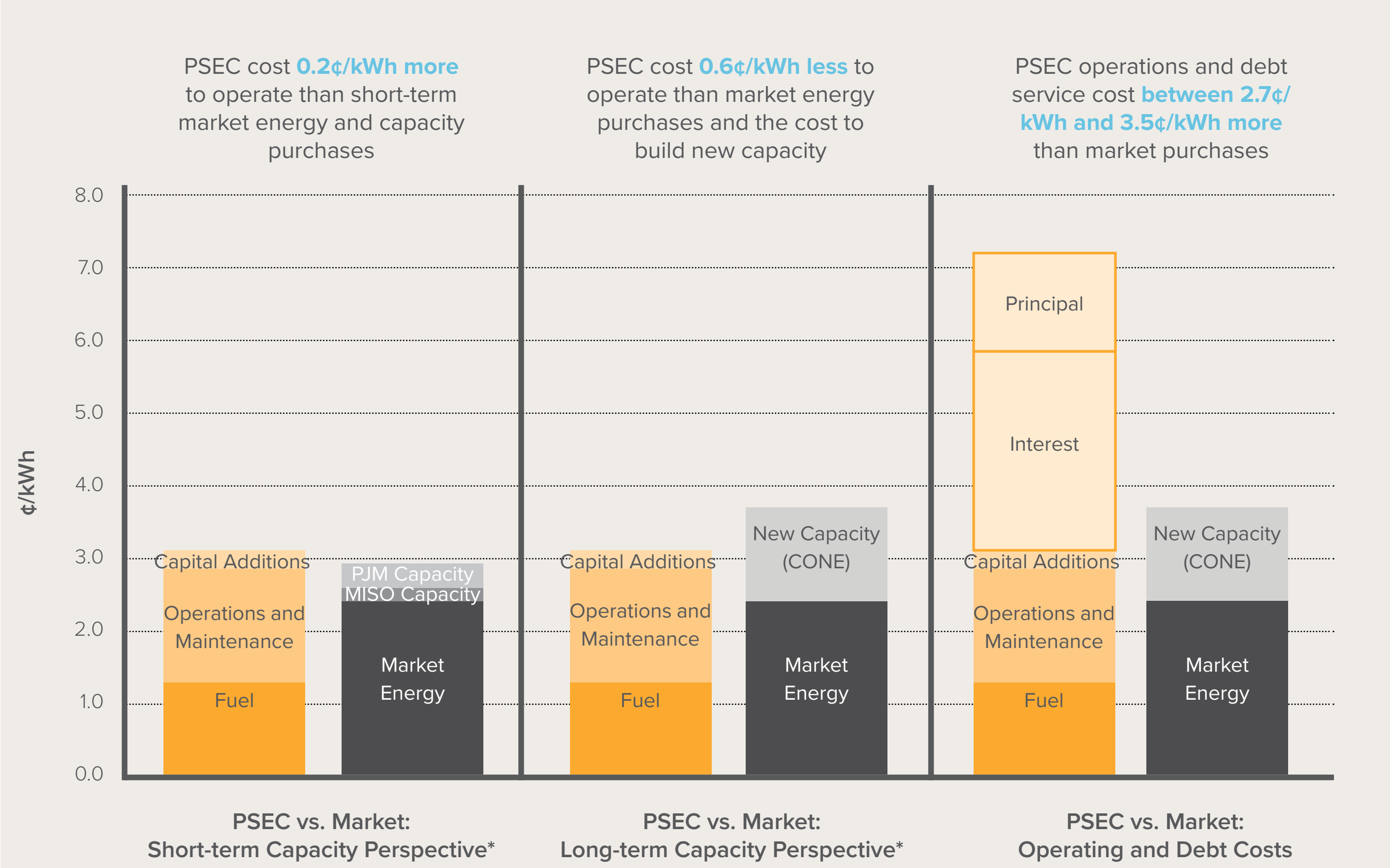
[vii] PSEC closure would likely have some impact on regional energy and capacity markets. This analysis assumes PSEC closure would not significantly impact clearing prices in regional energy and capacity markets.

Since 2016, PSEC has been roughly break-even compared with the market. Closing PSEC in 2016 would have at best resulted in slight savings to utilities owning the plant. At worst, it would have resulted in a rate increase less than 0.6¢/kWh.[viii] Including debt-related costs, PSEC remains much more expensive than market alternatives.

Past performance does not necessarily predict future economic performance. Long-term market and technology trajectories (discussed in *Options for Replacing Prairie State Energy Campus* below) all suggest that PSEC economics are only likely to deteriorate through 2030.

EXHIBIT 1

PSEC Historic Performance Compared with Market Purchases (2016–2019)



*Short-term capacity perspective on actual market value from annual market capacity auctions. Long-term capacity perspective based on cost to procure new capacity

[viii] Since owner utilities source power from multiple assets, they would be able to blend any PSEC cost increase into overall power costs, making increases significantly less than 0.6¢/kWh.

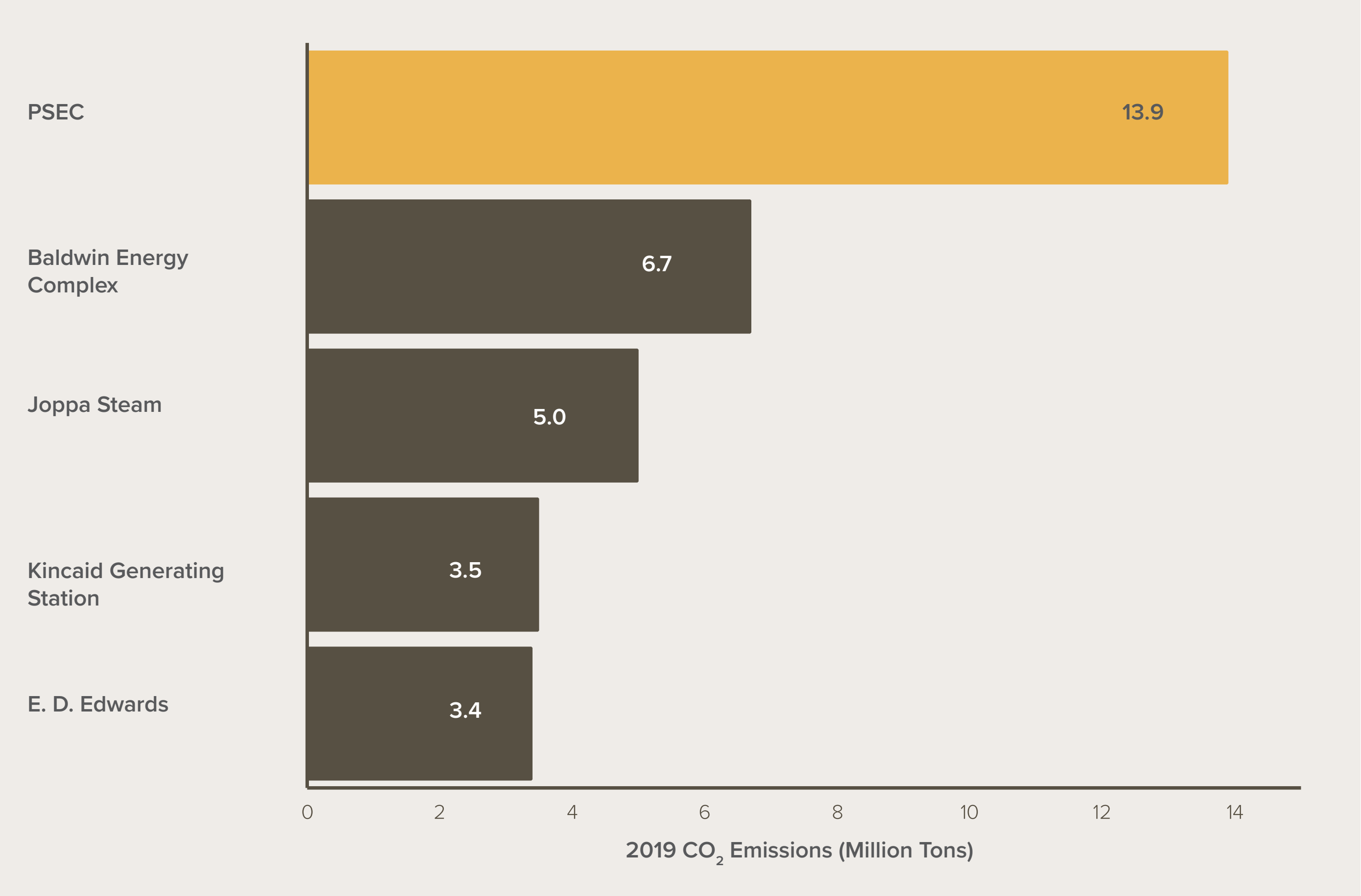
GREENHOUSE GAS EMISSIONS

In 2019, PSEC emitted greenhouse gasses equivalent to 2.7 million typical passenger cars—more than twice as much CO_2 as any other point source in Illinois (see Exhibit 2).[4] In addition to CO_2, PSEC emits more methane, SO_2, and NO_x than any other power plant in the state.[ix]

PSEC's emissions are high because PSEC produces more electricity than any other coal plant and because PSEC is carbon-intensive even when compared with much older coal plants. Exhibit 3 compares annual emissions reported to the EPA divided by electricity generated. Contrary to claims that PSEC is more efficient from an emissions perspective than other coal plants, PSEC's emissions rate is higher than other large coal plants in the state and significantly higher than power produced at natural gas, nuclear, or wind power plants.[x]

EXHIBIT 2

Illinois Top CO_2 Point Source Emitters (2019)

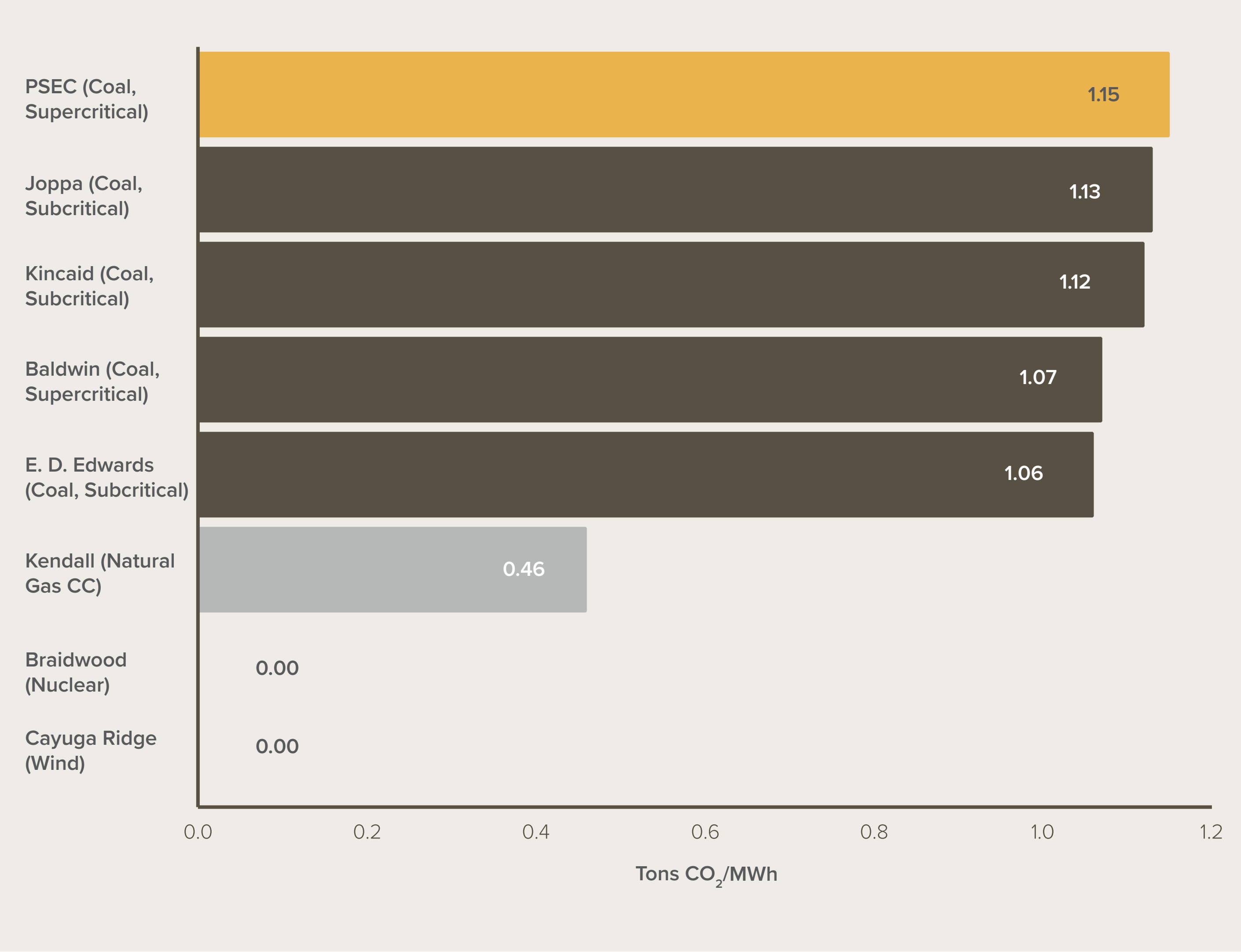


[ix] Though PSEC gross emissions for methane, SO_2, and NO_X are higher than any other plants in Illinois, several plants have higher emissions rates (SO_2/MWh and NO_X/MWh).

[x] Does not include emissions associated with plant construction, fuel production, or transportation.

EXHIBIT 3

Emissions per Unit Energy Generated for Select Illinois Power Plants (2019)



OPTIONS FOR REPLACING PRAIRIE STATE ENERGY CAMPUS

Long-term trends suggest that the cost of alternatives to PSEC will likely decline in price, while the cost of PSEC operation will increase. This section evaluates the future cost of alternatives to PSEC and lays out options for PSEC owners as they transition from PSEC operation to market purchases and clean energy solutions.

Long-term technology and market trends suggest that clean energy solutions and market purchases will be cheaper than PSEC operations before 2030 (see Exhibits 5 and 6).

Market energy and capacity purchases—In the future, plant owners could cease plant operations and instead buy energy and capacity from the markets. Over the next ten years, PSEC operations are expected to increase around 6% (in real terms). During the same time, energy investors expect market energy prices to decline 10% or more.[xi] While most analysts and market participants agree that energy prices will decline, market capacity prices are highly uncertain. Exhibit 4 shows PSEC net economics compared with the market under high-, medium-, and low-capacity scenarios and shows that by 2029 PSEC may be slightly more economic than market purchases or significantly less economic than market energy and capacity purchases.

EXHIBIT 4

2029 PSEC Net Economics Compared with Market Futures: Maximum-, Medium-, and Minimum-Capacity Scenarios[xii]

	Capacity Value ($/MW-Day)	PSEC Net Economics	Net Economics (¢/kWh)
Minimum-Capacity Price	$0	-$107 million	-1.0¢/kWh
Medium-Capacity Price	$80 (2016-2019 Average)	-$60 million	-0.5¢/kWh
Maximum-Capacity Price	$242 (CONE)	+$37 million	+0.3¢/kWh

Clean energy solutions—The cost of solar and wind have declined 67% and 44% respectively since PSEC opened in 2012.[5] As of 2019, wind power purchase agreements (PPAs) were being offered at $30/MWh,[6] and solar PPAs at below $35/MWh in the area.[7] This means that the cost to generate energy from PSEC is higher than the cost to build, own, and operate wind power projects today.

The costs of wind and solar are expected to continue to decline, as is the cost of battery storage and other clean energy solutions. Prior to 2030, PSEC is projected to cost more to operate than installing and operating a portfolio of clean energy solutions that includes wind, solar, battery storage, demand flexibility, and energy efficiency, which would provide energy and capacity to meet the needs of PSEC owners.

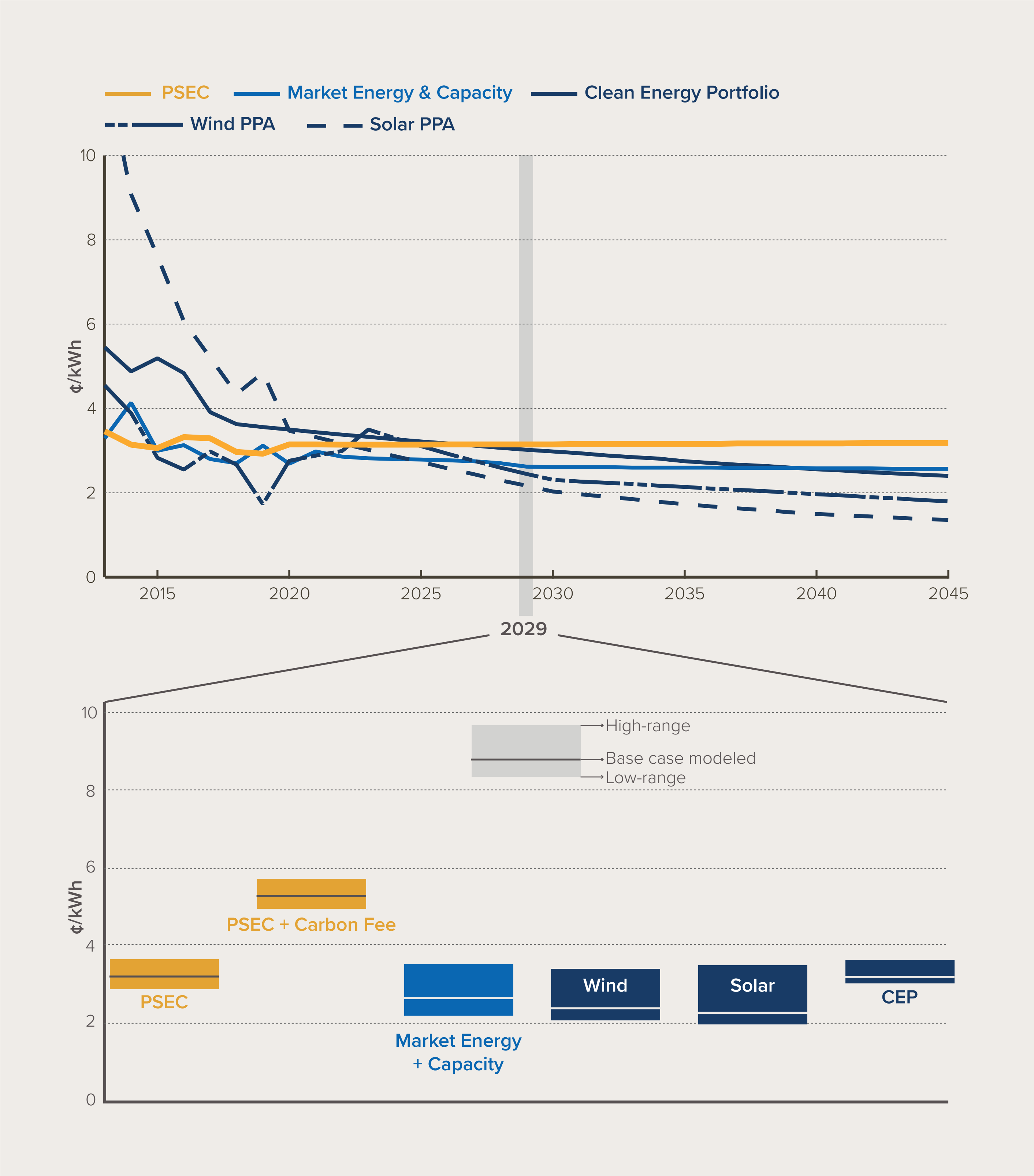
In December 2020, Congress extended solar and wind tax credits as part of the Taxpayer Certainty and Disaster Tax Relief Act. These recent tax extensions will provide more near-term opportunities to procure low-cost wind and solar. The tax extensions have not been included in Exhibit 5.

[xi] Based on MISO Illinois HUB futures and Henry HUB natural gas futures.

[xii] Market energy value based on MISO Illinois HUB futures. Assumes 2029 PSEC future operations are similar to 2016–2019 capacity factor. Does not include PSEC debt-related costs.

EXHIBIT 5

PSEC Operating Cost Compared with Clean Energy Solutions and Market Purchases 2012–2045



If PSEC owners wait until 2030 to replace PSEC services with alternatives, they may miss out on an opportunity to sign low-cost solar or wind PPAs. Multiple generation and transmission (G&T) cooperatives and municipal utilities are taking advantage of current market conditions to transform their power supply. PSEC owners should therefore consider the following steps to begin to manage risk, reduce costs, and replace PSEC services in a staged and strategic way.

a. **Define service needs currently met by PSEC**—Owners can project future hourly energy needs to begin to better understand how all or a portion of the services currently provided by PSEC could be substituted with market purchases or clean energy solutions.

b. **Define risk tolerance for new potential procurement strategy**—Utilities can manage (though not eliminate) the risk of future rate increases by owning generation assets like PSEC or by executing market transactions like hedging. It is not practical to eliminate all long-term rates risk, but smart planning can manage risk over time.

c. **Run an all-source RFP and procure market purchases and capacity accordingly**—All-source request for proposals provide insight on market options or clean energy solutions that can reduce costs and manage risk. Several Midwest utilities have decided to increase purchases of wind, solar, and battery storage as a result of all-source RFPs.[8]

d. **Make a plan for PSEC wind-down—including adjusted operations—according to results of above steps**—If PSEC owners procure new sources of energy and capacity, they may adjust plant operation to reduce total costs. This could involve decreasing plant production over time through increased ramping or seasonal mothballing. Modifying plant operations may provide savings to ratepayers and set the stage for retirement by 2030.

AVOIDING RATE INCREASES

There are ways to ensure that ratepayers don't experience a significant rate increase due to a PSEC closure in addition to the economic alternatives mentioned above. State policy can help further reduce the costs of alternative generation, for example through tax credits and grants for clean energy projects, and refinancing support can help alleviate the long-term burden of PSEC debt (see Appendix E).

Policy-enabled financing tools include securitization, which would need to be extended to public power providers, and state-subsidized debt restructuring at a lower interest rate. Additionally, through a "carbon bonus" policy, the state could help reduce the burden of debt repayments as an incentive for decreasing carbon emissions compared with a baseline. Engaging stakeholders and plant owners is a key component of identifying the most appropriate solution set to maximize the benefits and minimize the impacts of early PSEC closure.

A 2030 mandated closure of PSEC is unlikely to result in rate increases to electricity consumers in Illinois or neighboring states. Furthermore, if PSEC closure is combined with state-enabled refinancing options (securitization or subsidized debt) ratepayers will probably be better off if PSEC is required to be closed.

However, that does not mean ratepayers at PSEC-owner utilities will not see rate hikes in the coming years. Some utilities may decide to accelerate depreciation to prepare for a 2030 plant closure. Also, as the preceding analysis has shown, PSEC owners have failed to fully recover the cost of PSEC through their rates to date, and even if the plant is closed, the debt still needs to be repaid. Ratepayers may see rate increases in the coming years as plant owners adjust rates to account for the full cost of PSEC, whether or not PSEC is closed in 2030. Savings from lower-cost alternative generation and a state-supported retirement process will put plant owners and ratepayers in the best possible position to pay off the debt and move forward into the changing 21st-century energy landscape.

KEY POLICY OPTIONS AND OPPORTUNITIES

It is important that any Illinois clean energy legislation that mandates PSEC closure does not significantly and negatively impact PSEC ratepayers or Illinois taxpayers. Fortunately, PSEC ratepayers are unlikely to be worse off if PSEC is closed in 2030. And wind, solar, and other clean energy solutions are expected to continue to decline in price, making PSEC uneconomic well before 2030. Thus, economics alone might force PSEC to be closed before 2030. By proactively planning for plant closure with appropriate lead time, Illinois state policymakers and key PSEC stakeholders can help to lessen or eliminate any negative impacts on impacted communities and utilities by:

1. Ensuring energy costs do not increase,
2. Decreasing the long-term debt burden,
3. Supporting worker and community transitions, and
4. Redeveloping the site with renewable energy opportunities.

Ensuring energy costs do not increase

There are many ways to ensure that energy prices do not increase for ratepayers if PSEC is replaced by a clean energy portfolio by 2030. These include implementing the following policies:

- Carbon reduction bonus—A carbon reduction bonus provides a bonus or incentive to utilities and other large emitters that reduce their emissions compared with a base year. Such a bonus could be applied to PSEC closure and used by plant owners to help pay down the debt.

- Clean energy subsidies (tax credits, grants)—Tax credits and grants can help reduce the cost of clean energy solutions, making them even more favorable as alternative generation sources.

- Pollution fee—A pollution fee or carbon tax would increase the cost of PSEC and other fossil fuel generation. This would move forward the date at which time CEPs would cost-effectively replace PSEC.

Decreasing long-term debt burden

Under the scheduled payment trajectory, Illinois utilities will pay approximately $3.9 billion in interest and the remaining principal on PSEC debt[xiii] (see Appendix C). Policy-enabled finance solutions can also help lessen any impacts of this debt on ratepayers after 2030. These include ratepayer-backed securitization of remaining debt—which would require a change in the ratemaking process so that co-ops and munis are subject to Illinois Commerce Commission ratemaking authority—or a state-subsidized debt—in which the state helps pay off a portion of outstanding 2030 plant debt and replaces it with a 0% long-term loan. Federal debt-relief policies—in particular policies that relieve debt as long as utilities commit to reinvesting in clean energy or customer programs—could also help relieve the PSEC debt burden. In addition to providing direct savings, any policies that reduce debt held on the balance sheet of PSEC owners could help ensure that PSEC owners can access capital markets for future clean investments.

Supporting worker and community transitions

PSEC provides 600 jobs, considerable tax revenue, and other indirect benefits to workers and communities in Southern Illinois. Thus, supporting workers and communities during an early closure is critical. CEJA already includes components to directly address these issues such as direct support through Clean Energy Empowerment Zones and workforce training through Clean Jobs Workforce Hubs. In addition to training and new opportunities in the clean energy economy, there may also be significant jobs associated with plant and mine remediation in the years following retirement.

Redeveloping the site with renewable energy

Once remediated, the land that a coal plant occupies may be ideally suited for a solar farm or other renewable energy project. The PSEC property includes a substation, transmission, and 2,400 acres—enough to site 300–400 MW. Given the available land and existing infrastructure, the project would likely be built at prices 10% lower than other projects in the region. A solar project that size could generate millions of dollars in direct, indirect, and induced economic benefits.

REPURPOSING COAL POWER PLANTS

In addition to renewable energy development, coal sites are being repurposed for other activities.

- In Massachusetts, Brayton Point was the last remaining coal plant in the state when it was retired in 2017 due to unfavorable economics and state and regional policy pressures. Now, it is poised to become a first-of-its-kind logistics port, manufacturing hub, and support center for the US offshore wind industry. Construction of a 1,200 MW high-voltage direct current converter and 400 MW of battery storage—to convert and store electricity generated by offshore wind turbines—will begin in 2021, according to project developer Anbaric.

- In Alabama, Google has built a $600 million data center at the site of the former Widows Creek coal-fired power station. Data centers are planned at other former coal plants, including the site of the final coal plant in New York State.

[xiii] Debt figure based on publicly available documents. Some PSEC owners may have refinanced or restructured corporate debt and/or debt associated with PSEC to take advantage of 2020's historically low interest rates.

CONCLUSION

RMI's analysis shows that closing PSEC will not negatively impact ratepayers, and in fact, that both customers and plant owners will most likely save money if the plant is replaced with a clean energy portfolio of renewable energy, battery storage, energy efficiency, and demand flexibility.

Illinois lawmakers should consider the following to ensure Illinois citizens capture the economic and environmental benefits of plant closure:

- Maintain PSEC-closure as a component of comprehensive clean energy legislation.

- Include policy measures in any comprehensive clean energy legislation that will reduce long-term outstanding debt and assist in community and worker transitions through job training and investing in communities.

Keeping PSEC closure in comprehensive clean energy legislation can help overcome a collective action challenge that may keep PSEC owners from all agreeing to close the plant, and it can also help PSEC owners avoid the increasing liability over long-term coal ash disposal from PSEC.

PSEC owners should engage lawmakers, distribution utilities, and other stakeholders in creating solutions for a smooth transition from PSEC to cleaner and lower-cost solutions. By productively engaging now, PSEC owners will ensure maximum benefit to their communities, and give impacted communities the lead time necessary to gain maximum benefit from the energy transition.

ABOUT RMI

RMI ENERGY. TRANSFORMED.

RMI is an independent nonprofit founded in 1982 that transforms global energy systems through market-driven solutions to align with a 1.5°C future and secure a clean, prosperous, zero-carbon future for all. We work in the world's most critical geographies and engage businesses, policymakers, communities, and NGOs to identify and scale energy system interventions that will cut greenhouse gas emissions at least 50 percent by 2030. RMI has offices in Basalt and Boulder, Colorado; New York City; Oakland, California; Washington, D.C.; and Beijing.

Appendix A Cost to Operate PSEC

RMI estimated the cost to operate Prairie State Energy Campus from NIMPA financial statements and FERC disclosures accessed from S&P Global. NIMPA owns a 7.6% share of PSEC and PSEC is NIMPA's only owned generation asset, so NIMPA costs were extrapolated to estimate total plant costs.

NIMPA cash flow statements were used to estimate annual capital additions and costs related to debt. Recurring investments in the plant are required for long-term operation of the plant. These costs will vary considerably from year to year. Overall plant additions from 2016 to 2019 were typical for a plant of PSEC's size and age.[xiv]

Other PSEC owners may see significantly higher or lower debt-related costs, depending on the structure of their debt.

EXHIBIT A1

PSEC Operating and Debt Costs 2016–2019

	Source	2016	2017	2018	2019
Fuel Expense	S&P	$138,988,049	$146,431,344	$147,088,992	$155,321,087
Operating Expense	S&P	$94,831,401	$80,683,440	$84,932,509	$87,838,478
Maintenance Expense	S&P	$87,949,138	$86,296,086	$95,801,660	$84,601,304
Capital Additions	NIMPA	$30,697,368	$42,236,842	$15,092,105	$23,631,579
Total Annual Cost to Operate		**$352,465,956**	**$355,647,712**	**$342,915,266**	**$351,392,448**
$/MWh		$33.19	$32.90	$29.73	$29.34
Interest Net BAB Subsidy	NIMPA	$405,000,000	$282,513,158	$273,197,368	$267,368,421
Principal	NIMPA	$105,986,842	$146,710,526	$206,776,316	$138,486,842
Debt Total		**$510,986,842**	**$429,223,684**	**$479,973,684**	**$405,855,263**
$/MWh		$48.12	$39.70	$41.62	$33.88
Total Cost		**$863,452,798.53**	**$784,871,396.32**	**$822,888,950.47**	**$757,247,711.11**
$/MWh		$81.31	$72.60	$71.35	$63.22

[xiv] Based on comparison to EIA's NEMS approach to estimating coal incremental capital additions.

PSEC ownership is complex. Research on plant ownership revealed several insights:

- No single entity or state owns the majority of the plant. American Municipal Power (AMP) is the largest owner with 23% ownership share. Ownership share of the remaining power providers ranges from 15% (IMEA) to 5%.
- PSEC accounts for more than 40% of energy supplied by three Illinois power providers (NIMPA, Prairie Power, and IMEA). PSEC provides a significant, but smaller portion of total energy for the other power providers.
- Muni JPAs own 79% of the plant compared with 21% ownership by co-op G&Ts. The Illinois portion of plant ownership is roughly split between muni JPAs and co-op G&Ts.
- Illinois utilities own the largest portion of the plant (40%). PSEC also serves utilities in seven other states.
- Five of nine power providers serve Illinois utilities. Four of the providers (IMEA, Prairie Power, SIPC, and NIMPA) exclusively serve Illinois utilities.
- Power providers receive energy from the plant proportional to their ownership share. For example, since IMEA owns 15% of the plant, it receives 15% of the plant's output.
- All owners have equivalent shares in the plant and the mine. Prairie State Energy Campus and Lively Grove Mine are essentially a package deal: 15% ownership of the plant implies 15% ownership of the mine.

EXHIBIT B1

Ownership Summary by PSEC Owner*

PSEC Owner	Type	Headquarters	PSEC Share	Utilities Served†	State(s) Served†	Illinois Utilities†	Total 2018 Sales (MWh)‡	PSEC as % of 2018 Sales‡
American Municipal Power (AMP)	Muni JPA	Columbus, OH	23.3%	68	MI, OH, VA, WV	0	17,100,000	15.7%
Illinois Municipal Electric Agency (IMEA)	**Muni JPA**	**Springfield, IL**	**15.2%**	**32**	**IL**	**32**	**4,001,248**	**43.7%**
Indiana Municipal Power Agency (IMPA)	Muni JPA	Carmel, IN	12.6%	61	IN, OH	0	6,372,000	22.9%
Missouri Joint Municipal Electric Utility Commission (MJMEUC)	Muni JPA	Columbia, MO	12.3%	70	MO	0	6,287,771	22.6%
Prairie Power Inc.	**Co-op G&T**	**Springfield, IL**	**8.2%**	**10**	**IL**	**10**	**N/A**	**57.9%**
Southern Illinois Power Cooperative (SIPC)	**Co-op G&T**	**Marion, IL**	**7.9%**	**7 co-ops 1 muni**	**IL**	**8**	**N/A**	**N/A**
Kentucky Municipal Power Agency (KMPA)	Muni JPA	Paducah, KY	7.8%	2	KY	0	N/A	N/A
Northern Illinois Municipal Power Agency (NIMPA)	**Muni JPA**	**Geneva, Batavia, Rochelle, IL**	**7.6%**	**3**	**IL**	**3**	**N/A**	**
Wabash Valley Power Alliance	Co-op G&T	Indianapolis, IN	5.1%	23	IL, IN, MO	3	7,277,000	8.0%

* Gray rows indicate plant owner serves only Illinois utilities.

† Utilities and states served by PSEC. Not all AMP customers buy power from PSEC.

‡ 2018 fiscal year total sales by PSEC owner except Prairie Power (2017) and Wabash (2018 est.). In some instances, 2018 sales were not available (N/A). Data sources were power provider financial statements.

** PSEC is the only large generation asset owned by NIMPA.

Appendix C

Summary of Debt and Interest Rate by Plant Owner

Data for Exhibit C1 was sourced from publicly available financial documents. In many instances financial data was either not available, or available data failed to distinguish between PSEC-related debt and other debt.

Research on debt revealed the following:

- The initial cost to build the plant and mine was $5 billion. This analysis assumed that initial costs were divided between plant owners proportional to their ownership stake.
- Current remaining debt balance related to PSEC is greater than initial cost share and net book value in all cases where debt data is transparent.
- The average interest rate on PSEC debt is estimated to be 5.3%, before federal subsidies for Build America Bonds (BAB).

EXHIBIT C1

Summary of Debt by PSEC Owner

PSEC Owner	Initial Cost Portion	PSEC Book Value†	Remaining PSEC Debt	Average Debt Interest Rate
American Municipal Power (AMP)	$1,100,000,000	$1,015,610,385	$1,633,865,000	5.8%
Illinois Municipal Electric Agency (IMEA)	$740,000,000	$750,027,862	N/A	6.7%
Indiana Municipal Power Agency (IMPA)	$620,000,000	$628,215,000	N/A	4.7%
Missouri Joint Municipal Electric Utility Commission (MJMEUC)	$600,000,000	$647,614,290	$733,721,967	4.7%
Prairie Power Inc.	$400,000,000	$376,671,356	N/A	5.8%
Southern Illinois Power Cooperative (SIPC)	$390,000,000	N/A	N/A	
Kentucky Municipal Power Agency (KMPA)	$380,000,000	$394,449,000	$470,632,552	5.1%
Northern Illinois Municipal Power Agency (NIMPA)	$370,000,000	$390,722,000	$440,800,000*	4.7%*

† Book value net of depreciation

* Remaining debt net of Build America Bonds subsidy. This is the amount of debt and corresponding interest rate, assuming the federal government continues to provide BAB subsidy. Ignoring BAB subsidy, the gross debt is $466,693,000 and the interest rate is 5.73%.

Sources: Initial Cost: IEEFA (2015); PSEC Book Value and Debt 2018 financial statements

Our clean energy portfolio (CEP) model calculates the composition of least-cost portfolios of clean energy resources that can provide the same grid services as an existing power plant. The model requires that the CEP meet three key services:

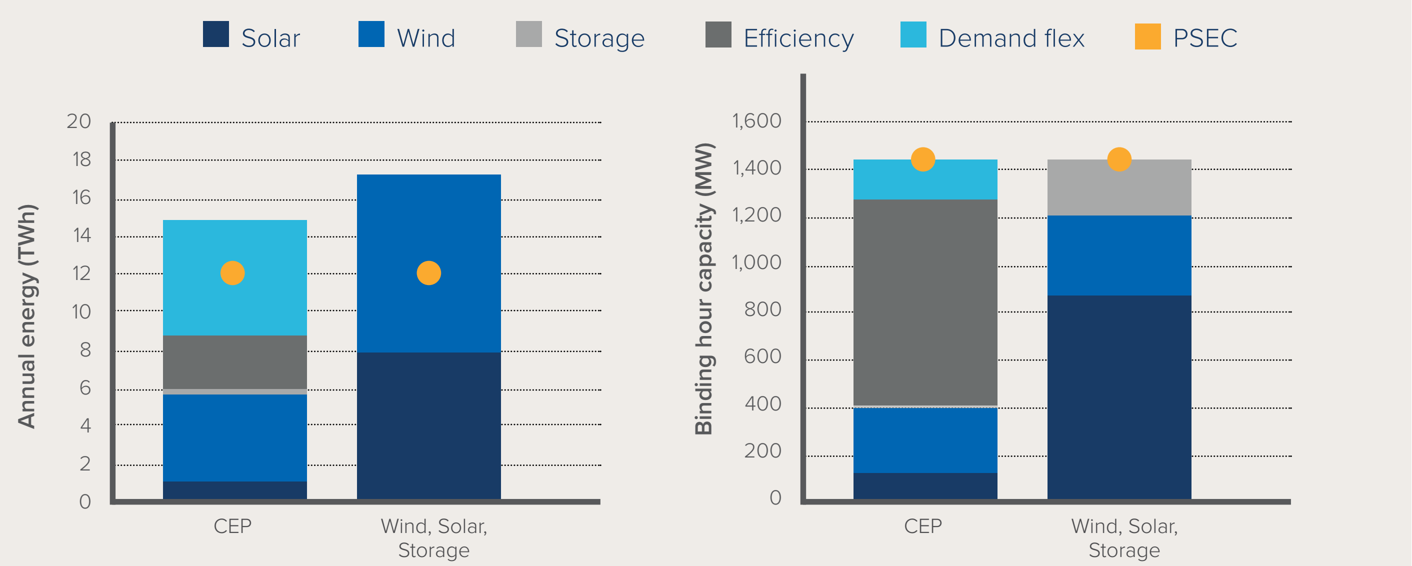
- Monthly energy: The CEP must produce at least as much energy each month as the existing plant. We use PSEC's average monthly generation from 2017 and 2018.
- Peak-hour capacity: The total power output (in megawatts) of the CEP must match or exceed PSEC's average output during the top 100 hours of MISO gross load during 2017 and 2018. These hours can be, but are not necessarily, sequential.
- Flexibility: The total power output (in megawatts) of the CEP must match or exceed PSEC's seasonally adjusted nameplate capacity during the hour when the region experiences its greatest one-hour increase in load. Further, the model requires that the CEP not exacerbate ramping issues (i.e., the "duck curve"), by requiring that during the largest four-hour ramp-down of CEP solar generation, CEP total power output must be able to remain constant or increase (e.g., by charging storage during peak solar PV output and discharging as solar PV power output drops).

We use linear programming-based optimization to compute the least-cost combination of clean energy technologies that provide the required services. We include five technologies in CEPs:

- Energy efficiency: We model the use of programs (either utility- or other administrator-enabled) to reduce electricity use while maintaining or improving the quality of end-use services. We estimate hourly demand reductions associated with these programs using historic regional end-use load data, and model the associated program administrator costs based on regional data.
- Demand flexibility: We model the use of programs (either utility- or other administrator-enabled) to shift the timing of electricity use while maintaining the quality of end-use services. We estimate hourly demand reductions associated with these programs using historic regional end-use load data, and model the associated program administrator costs based on regional data.
- Utility-scale wind: We model the contributions of wind projects using regional hourly production profiles and analyst cost forecasts.
- Utility-scale solar: We model the contributions of solar projects using regional hourly production profiles and analyst cost forecasts.
- Battery energy storage: We model the capability of batteries to meet peak demand and provide ramping flexibility. We allow the model to optimize a combination of one- to eight-hour duration batteries. We use analyst forecasts for battery costs.

EXHIBIT D1

PSEC-Replacement Clean Energy Portfolio Results: 2028

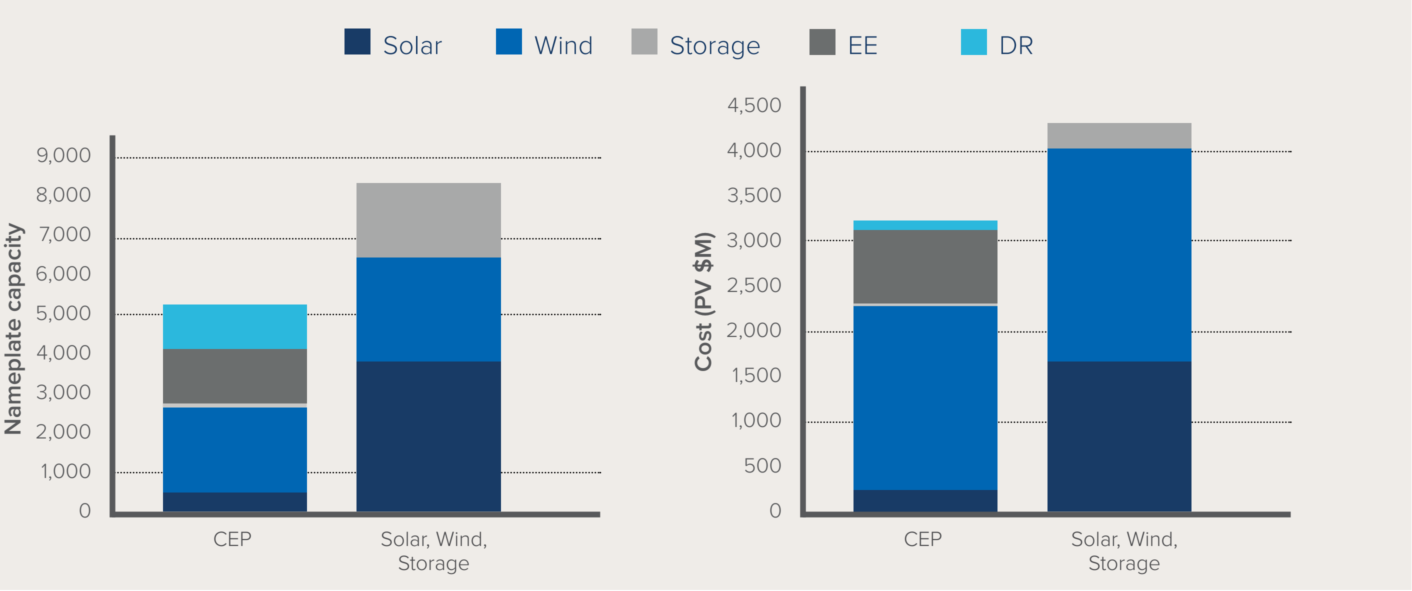


Notes:

- Nearly all the capacity hours are during the summer in the mid to late afternoon. This explains the selection of the particular efficiency end uses (industrial, residential space cooling, and commercial lighting) in the CEP case, and solar when efficiency is restricted.
- Storage is generally only selected when other resources are not available to meet capacity needs. The fact that the CEP case has very little storage means that nearly all capacity needs can be met by solar, wind, efficiency, and demand flexibility.

EXHIBIT D2

CEP Cost



Note: Cost is based on an in-service year of 2028 and is in 2019 dollars.

Key Assumptions

- Energy reduction from energy efficiency (EE) cannot account for more than 50% of the monthly energy requirement on an annual basis. We also limit total available EE to the lesser of twice the fraction of PSEC's capacity to the planning area's peak demand or 25% of the planning area's assessed EE availability.
- Power reduction from demand flexibility cannot account for meeting more than 50% of the required power output during peak demand hours. We also limit demand flexibility to the lesser of twice the fraction of PSEC's capacity to the planning area's peak demand or 25% of the planning area's assessed demand flexibility availability.
- We assume that the top hours of MISO load are the hours where PSEC's capacity is most needed.
- We assume solar installations benefit from a 10% investment tax credit (ITC) in 2028; we do not apply the ITC to storage.
- We do not include the production tax credit.
- In all cases, the CEP generates the energy needed to charge the battery storage. We assume a round-trip charge/discharge efficiency of 90%.
- Storage operating expenses are dominated by the need to replace lost capacity that accumulates with each cycle. We assume 0.03% of battery capacity is lost each time the battery is cycled.
- We do not value any ancillary services that could be provided by the CEP or PSEC.
- We assume a 20-year life for the CEP. We adjust the capital expenditure costs of resources with useful lives that are longer (e.g., solar PV) or shorter (e.g., some efficiency measures) than 20 years, by taking the present value of 20 years of that resource's annualized capital expenditure. We use a real discount rate of 6%.

Sensitivities and Drivers

- One area of significant uncertainty for CEPs is the future costs of individual resources, particularly wind, solar, and storage. Different assumptions about the cost trajectories of resources can change the levelized cost of a CEP by 10%–20% but have almost no effect on the composition of the portfolio.
- In our base case analysis, we allow the CEP model to select targeted demand-side management programs (i.e., energy efficiency and demand flexibility) that can provide energy, capacity, and flexibility. Efficiency and demand flexibility are among the most cost-effective resources available to utility planners and investors. They provide grid services comparable to generation and storage technologies, but usually require favorable state policies to scale effectively. As a sensitivity analysis, we also consider portfolios of only wind, solar, and storage that omit EE and demand flexibility. A CEP without demand-side management is 33% more expensive in present value terms, and 15% more expensive in levelized cost terms.

EXHIBIT E1

Summary of Refinancing Options

	Do Nothing (BAU)	2020 Securitization (3.5%)	2030 Securitization (3.5%)
Duration of Security/Debt	22 years	22 years	12 years
Nominal Payments by IL Owners	$3,572,320,009	$3,193,668,860	$3,417,439,419
Savings (Nominal)	n/a	$378,651,150 $3.76/MWh*	$154,880,590 $2.82/MWh
NPV Payments by IL Owners (2020$)	$1,820,102,372	$1,605,724,515	$1,760,225,317
Savings (NPV)	n/a	$214,377,857	$59,877,055
Requires Full ICC ratemaking?	No	No	No
Requires Partial ICC ratemaking?	No	Yes	Yes
Shifts costs to non-owners	No	No	No
Pros	Ratepayers and distribution utilities not directly tied to debt/security (i.e., leaves open option for G&T debt restructuring/bankruptcy)	Maximum savings (nominal and NPV) to ratepayers	Significant ratepayer savings Securitization coincides with plant closure
Cons	Highest payments over time (without refinancing)	Requires munis/co-ops to be subject to full or partial ICC ratemaking jurisdiction	Less savings than 2020 securitization Interest rate for security in 2030 is uncertain
Options/Alternatives	Refinancing through corporate bond issuance or municipal debt	Timing of security; full vs. partial ICC jurisdiction	Extend security to out-of-state owners
Key Remaining Questions	Can asset owners or municipalities refinance debt at a rate equal to or lower than securitization?	Will the market accept or require a premium for security with only partial ICC oversight? What's the cost to arrange this security?	What's the risk of waiting until 2030 to securitize? Is it possible to include out-of-state utilities in a ratepayer-backed security with ICC oversight?

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2. *Short-Term Energy Outlook*, US Energy Information Administration, February 9, 2021, **https://www.eia.gov/outlooks/steo/report/coal.php.**

3. "Morgan Stanley Expects a Surge of Renewables, Coal Retirements," *Public Power*, January 16, 2020, **https://www.publicpower.org/periodical/article/morgan-stanley-expects-surge-renewables-coal-retirements.**

4. "2018 and 2019 Annual Power Plant Emissions, All Units, CO2," US Environmental Protection Agency Clean Air Markets Division, February 10, 2020, **https://www.epa.gov/sites/production/files/2020-02/annual_emission_comparison_2018_vs_2019.xlsx.**

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