Redacted Version

Exelon Illinois Nuclear Fleet Audit

Findings and Recommendations

Prepared for Illinois Environmental Protection Agency

April 14, 2021

AUTHORS

Divita Bhandari
Max Chang
Philip Eash-Gates
Jason Frost
Steve Letendre, PhD
Jackie Litynski
Cheryl Roberto
Andrew Takasugi
Jon Tabernero
Rachel Wilson

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 3
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

This page left intentionally blank

CONTENTS

EXECUTIVE SUMMARY

On August 20, 2020, Exelon Generation (Exelon) announced its intention to retire the Byron Nuclear Station (Byron) in September 2021 and the Dresden Nuclear Station (Dresden) in November 2021. In January 2021, the Illinois Environmental Protection Agency (IEPA) selected Synapse Energy Economics (Synapse) to conduct a financial audit of Exelon's claims regarding the financial outlook for its Byron and Dresden plants, as well as Exelon's Braidwood and LaSalle nuclear plants. This report presents Synapse's findings regarding the financial outlook for the four nuclear plants (Byron, Dresden, Braidwood, and LaSalle) over an analysis period of five years (2021–2025) and 10-years (2021–2030).

For context, analyses of nuclear plant financials have customarily utilized linear trajectories for future revenues and costs. This has led to debates about the timing of analysis, the appropriateness of assumptions, the determination of uncertainties, and the magnitude of future risks. As an example, one regularly debated issue is the assumption of fixed certainty for operational and market risk with the inclusion of cost adders. We find the various outcomes impacting the future profitability for a nuclear plant to be too complex to solve directly.

To account for the likelihood of various outcomes, we incorporated a Monte Carlo simulation that encompassed distribution and probabilities of revenues and costs for the four plants over the next five and 10 years. This flexibility enhanced the usefulness of our analysis over analyses based upon the assignment of fixed estimates for revenues and costs. The Monte Carlo simulation identified possible results by applying a probability distribution to inputs with inherent uncertainty. The simulation then recalculated results 10,000 times, each time using a different set of inputs randomly selected from within minimum and maximum values for the inputs. After this, the simulation developed a distribution of net present values for each of the four plants for the analysis period using Exelon's discount rate of [redacted] percent without a subsidy and a lower Synapse discount rate of [redacted] percent with a subsidy.

Our Monte Carlo simulations identified the range of possible net present values for the future operation of four plants. The results represent a span of potential future market and operational conditions inclusive of Exelon's expected future expenses, Synapse's forecast of plant revenues, and probabilistic likelihood of unanticipated plant outages based on 10 years of operating experience and market data for Exelon's 11 Illinois nuclear units across the six plants.

Synapse finds:

- The Byron plant has a five-year expected net present value (NPV) of $31 million using Exelon's discount rate. Our Monte Carlo analysis found that 95 percent of the iterations will be above an NPV of -$30 million.
- The Dresden plant has a five-year expected NPV of -$87 million using Exelon's discount rate. Our Monte Carlo analysis found that 95 percent of the iterations will be above a net present value of -$139 million.

- Both the Braidwood and LaSalle plants have positive expected NPVs for the five-year period. The expected NPV for Braidwood is $69 million with 95 percent of the iterations above $7 million and LaSalle showed an NPV of $293 million with 95 percent of the iterations above $232 million.
- The 10-year expected NPV for the Byron plant is $111 million using the Exelon discount rate. The 10-year expected NPV for the Dresden plant is also positive. We note that the 10-year results assume that Dresden Unit 2 retires as scheduled in 2029, since Exelon has not announced any plans to extend the current license.
- In an Illinois Carbon Price Scenario with prices comparable to the Regional Greenhouse Gas Initiative (RGGI) prices starting in 2023, our five-year expected NPVs are $91 million for Byron with 95 percent of the iterations above $28 million and -$39 million for Dresden with 95 percent of the iterations above -$92 million. These finding indicate that modest carbon prices would benefit the financial outlook of the two nuclear plants.
- [redacted]
- [redacted]
- [redacted]

As a private entity, Exelon will have profitable years and unprofitable years. Exelon is not regulated by the Illinois Commerce Commission, so the state does not have an obligation to ensure that Exelon shareholders have an opportunity to realize a return each year on their investment in the plants. That said, our analysis demonstrates that Byron and Dresden do face real risk of becoming uneconomic in the near term. This has implications for Illinois's policy goals because the plants generate carbon-free electricity that is currently undervalued or even ignored within current wholesale electricity markets. In addition, the plants employ hundreds of workers directly and contribute to the economies of numerous Illinois communities. Illinois could reasonably determine that it is in the public interest for the plants to remain in operation, warranting public support.

State support of the Exelon nuclear power plants could help provide certainty for the plants through the period of anticipated risk. [redacted] State support could be part of a strategy for the Illinois economy to transition to less carbon-emitting resources. To structure the support efficiently, state support would require cooperation from Exelon to be transparent with its finances to ensure that state support is provided only when required to support the economic operation of the plants.

Synapse Recommends:

If Illinois determines it is in the interest of state public policy to support the existing nuclear plants, then Synapse recommends that Illinois develop a program that offers financial support for the Byron and Dresden plants only when the plants require this support. Such a program should include the following features:

- This program need not extend beyond five years and could be re-evaluated at the end of the five-year period. The 10-year expected NPVs for Byron, LaSalle, and Braidwood are all positive. The 10-year NPV for Dresden is also positive but may be affected by the assumed retirement of Unit 2 in 2029.

- Illinois could consider of a subsidy rate of $1.00/MWh for Byron and $3.50/MWh for Dresden that would ensure that 95 percent of the five-year expected NPVs for each plant remains above zero at the Synapse discount rate in the Monte Carlo analysis. For illustrative purposes, a $3.00/MWh rate would collect approximately $100 million per year from ratepayers for the two plants.

- Alternatively, If Illinois adopts a carbon price, the State could consider a subsidy rate of $2.50/MWh for Dresden only that would ensure that 95 percent of the five-year expected NPVs for each plant remains above zero at the Synapse discount rate in the Monte Carlo analysis. No subsidy would be required for Byron in the Carbon Price Scenario.

- While Synapse recommends no particular mechanism, any subsidy for the output of the two plants should be based on each plant's financial need. No subsidy should be paid without demonstration of actual need. Such need could be determined by either actual costs and revenues or based on projected energy prices relative to the projections developed in this analysis. This process should occur annually and should be transparent and formulaic for all parties.

- [redacted] (See Appendix D for an explanation of these optimization efforts.)

    - [redacted]

    - [redacted]

    - [redacted]

The table below summarizes our findings for the four plants and includes information for Exelon's Clinton and Quad Cities plants that already receive zero emission credits (ZECs) and are not part of this analysis.[1]

Table ES- 1. Summary of findings

Plant	License Expiration Date(s)[2]	Nameplate Capacity (MW)[3]	Five-year Expected Net Present Value at Exelon's Discount Rate (millions)[4]	Subsidy Appropriate?	Five-Year Recommend Subsidy Amount ($/MWh)
Braidwood	2046, 2047	2,386	$69	No	none
Byron	2044, 2046	2,347	$31	Yes	$1.00
Clinton	2027	1,080	N/A	N/A	N/A
Dresden	2029, 2031	1,845	-$87	Yes	$3.50
LaSalle	2042, 2043	2,320	$293	No	none
Quad Cities	2032, 2032	1,403	N/A	N/A	N/A

Notes:
Clinton and Quad Cities currently receive ZECs from the 2016 CEJA. These ZECs expire in 2027.
Exelon owns 75 percent of the Quad Cities Nuclear Station. Values presented represent the portion owned by Exelon

---

[1] Exelon's Clinton and Quad Cities plants currently receive ZECs through 2027. Synapse did not conduct financial analysis of those two plants for the five-year and 10-year period.

[2] 50_EXC_Audit_Response.

[3] Exelon Corporation. Form 10-K Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the Fiscal Year Ended December 31, 2020. Page 341. Available at: https://investors.exeloncorp.com/static-files/ab8f2e58-fb68-4f1c-9197-bdca30371726

[4] Monte Carlo Analysis Results.

1. BACKGROUND

1.1. Summary of Illinois Plants

Exelon currently operates six nuclear plants within the State that contain a total of 11 reactors. With 12,415 megawatts (MW) of nuclear nameplate capacity, Illinois ranked first in the country in terms of nameplate capacity and first in total energy generation (100,246 gigawatt-hours, or GWh) from nuclear units in 2020.[5] Figure 1 below provides a summary of the six plants.

Figure 1. Summary of Exelon's Illinois nuclear plants

Plant	Nameplate MW	Unit	Commercial Operation	Age	Operating License Expiration	Years to License Expiration
Byron	2,347	1	9/16/1985	35	10/31/2044	23
		2	8/2/1987	33	11/6/2046	25
Braidwood	2,386	1	7/29/1988	32	10/27/2046	25
		2	10/17/1988	31	12/18/2047	26
Clinton	1,080	1	9/15/1987	33	4/17/2027	6
Dresden	1,845	3	6/9/1970	50	12/22/2029	8
		4	11/16/1971	49	1/12/2031	10
LaSalle	2,320	1	1/1/1984	37	4/17/2042	21
		2	10/19/1984	36	12/16/2043	22
Quad Cities	1,403	1	2/15/1973	48	12/14/2032	11
		2	3/10/1973	48	12/14/2032	11

Source: Exelon 2020 10K and other nuclear plant data.

On August 27, 2020, Exelon Generation (Exelon) announced its intention to shut down the Byron and Dresden plants starting in September 2021 for Byron and November 2021 for Dresden.[6] Exelon claims that projected losses for the two plants were in the hundreds of millions of dollars due to declining energy prices and market rules that favored fossil fuel plants.[7] [redacted]

[5] Pennsylvania was second with 9,532 MW of nameplate capacity and 76,521 GWh in 2020. Data is available from the U.S. Energy Information Administration web page on nuclear generation, available at https://www.eia.gov/nuclear/generation/.

[6] Exelon. "Exelon Generation to Retire Illinois' Byron and Dresden Nuclear Plants in 2021." August 27, 2020. Available at https://www.exeloncorp.com/newsroom/exelon-generation-to-retire-illinois%E2%80%99-byron-and-dresden-nuclear-plants-in-2021.

[7] Ibid.

[redacted]. This may contribute to the relative historical and current financial outlook of the four plants since, all things being equal, higher heat rate plants operate less efficiently than lower heat rate plants.[8]

The last time Exelon announced planned nuclear retirements due to insufficient revenues—Exelon announced its intention to retire the Clinton and Quad Cities plants in 2016[9]—Illinois responded by passing legislation granting subsidies for the two plants through 2027. This prompted Exelon to rescind its decision to retire the two plants early.[10]

1.2. Historical Revenues

Historical revenues for each plant for the last 10 years are presented in the figures below by energy, capacity, and other revenues.

Figure 2. Total revenue by plant by calendar year (nominal dollars)

[redacted]

Source: Exelon historical cashflow data.

[8] EXC Audit 17.

[9] Exelon. "Exelon Announces Early Retirement of Clinton and Quad Cities Nuclear Plants." June 2, 2016. Available at https://www.exeloncorp.com/newsroom/clinton-and-quad-cities-retirement.

[10] Exelon. "Governor Rauner Joins Hundreds of Community Members, Local Business Leader, Environmental Groups and Nuclear Plant Employees for Signing of Future Energy Jobs Bill." December 7, 2016. Available at https://www.exeloncorp.com/newsroom/governor-rauner-signing-of-future-energy-jobs-bill.

Figure 3. Capacity revenues by plant overlayed on the corresponding plant's energy revenues (Nominal $)

[redacted]

Source: Exelon historical cashflow data.

Note: Plant capacity revenues are overlayed (not stacked) against energy revenues; this figure shows that energy revenues have consistently contributed to a much larger amount of the revenue than capacity revenues.

(*) Capacity and ZEC revenue are only applicable for plants receiving ZEC revenues (Clinton and Quad Cities).

Energy revenues

The area covered by the Commonwealth Edison service territory of Illinois operates within the broader construct of the PJM region, which includes the movement of wholesale electricity in all or part of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia) and the District of Columbia. Overall, PJM serves 65 million people with a peak load of 165,563 MW and with 186,788 MW of generating capacity.[11]

The PJM energy market procures electricity to meet consumers' demands both in real-time (five minutes) and on a day-ahead (one-day forward) basis. PJM uses locational marginal prices (LMP) to price energy purchases and sales. The LMP is the clearing price in energy markets based on the cost of generating the last quantity of electricity needed to meet demand in the moment (and location). The clearing price is paid to all accepted bidders in that specific location. PJM ensures the lowest production cost by requiring generators to bid the price and amount of generation at generator-specific locations (*i.e.*, a generator "bus") and accepting bids from the lowest offer prices until the accepted amount meets the demand.

[11] PJM. *PJM 2019 Annual Report*. "Welcome." 2020 Available at https://services.pjm.com/annualreport2019/welcome.

Because nuclear units are slower to increase or decrease their energy output and generally run continuously at maximum output, they tend to bid as price-takers in energy markets. This ensures that they can continuously sell their energy, regardless of the clearing prices in the day-ahead and real-time energy markets.

Figure 3 above shows that from 2011 through 2020, the four plants generated [redacted] billion in energy revenues.[12] Overall, energy revenues comprise approximately [redacted] percent of the units' revenues. This portion varies slightly among the four plants. Energy revenues have and continue to represent the largest portion of total revenues for the six nuclear plants.

Capacity revenues

Capacity revenues represent the next largest portion of total revenues for the six nuclear plants, after energy.[13] Following a period of [redacted] as illustrated in Figure 4 below, PJM capacity market revenues for Exelon's nuclear plants [redacted]. [redacted] in PJM capacity market revenues were due to rising market clearing capacity prices in PJM's annual Base Residual Auction (BRA) for the COMED zone, or locational delivery area (LDA). Rising capacity revenues, combined with stable or declining energy revenues [redacted], resulted in [redacted] percent of company total revenue from the PJM capacity revenues as illustrated in Figure 4 below.

[redacted], capacity market revenues for nearly all plants trended similarly, rising, or falling subject to the BRA market clearing prices.

Beginning in 2018, however, Quad Cities capacity revenues diverged from all other Exelon nuclear plants and declined [redacted] year over year, while capacity market revenues for all other plants rose [redacted] year over year. The decline in capacity revenues resulted from Quad Cities failing to clear the BRA for the 2018/2019 Delivery Year.[14] PJM capacity revenues for Quad Cities for the 2018 calendar year are based on the capacity clearing prices for the BRAs for both the 2017/2018 and 2018/2019 delivery years.[15] The company received payments from January through May based on the 2017/2018 market clearing price and for June through December based on the 2018/2019 capacity price. Quad Cities again failed to clear the 2019/2020 and the 2020/2021 BRAs, leading to a continued sharp reduction in capacity market revenues for the plant.

---

[12] EXC Audit 10.

[13] EXC Audit 10. The Clinton and a portion of the Quad Cities plants are located in the MISO RTO, and thus do not receive PJM capacity market revenues.

[14] Capacity market revenues in 2018 would in theory, comprise [redacted] percent of revenue in the 2017/2018 BRA delivery year and [redacted] percent of revenue in 2018/2020 BRA, consistent with the PJM delivery year definition of June through May. See Appendix C for more details.

[15] PJM delivery year is from June 1st through May 31st.

Capacity market revenues for Byron diverged from the other Exelon plants in 2019, when capacity revenues for the plant [redacted] year over year, while capacity revenues from all other plants [redacted] year over year. Unlike Quad Cities, however, Byron was able to clear a portion of its capacity offer in the 2019/2020 BRA. We describe the rationale for this below.

In the calendar years 2021 and 2022, capacity market revenue trends for all plants are likely to diverge from historical trends due to the results of the 2021/2022 BRA presented in Figure 5. This figure shows a decline in cleared capacity for three of the five Exelon nuclear plants in PJM. In this most recent BRA, Byron cleared just [redacted] of its capacity offer, Dresden failed to clear at all, and Braidwood cleared [redacted] of its capacity offer. In contrast, Quad Cities' capacity offer cleared for the first time since the 2017/2018 BRA.

Figure 4. Capacity revenues as a percentage of total revenues by nuclear plant (PJM only)

[redacted]

Source: EXC Audit 10.

Figure 5. Cleared capacity by plant for each Base Residual Auction (PJM only)

[redacted]

Source: Exelon historical capacity market data.

The PJM Internal Market Monitor (IMM) reviews the results for each of PJM's annual capacity auctions. For the 2021/2022 Delivery Year, the IMM states, "Based on the data and this review, the MMU [market monitoring unit] concludes that the results of the 2021/2022 RPM Base Residual Auction were not competitive as a result of economic withholding by resources that used offers that were consistent with the net CONE times B offer cap but not consistent with competitive offers based on the correctly calculated offer cap."[16] Furthermore, for nuclear units participating in the 2021/2022 delivery year auction, the IMM concludes, "Nuclear offer behavior changed in the 2021/2022 RPM Base Residual Auction compared to prior auctions. More nuclear capacity was offered at higher sell offer prices and fewer nuclear MW cleared."[17]

Bidding behaviors

Exelon's bid data[18] from the 2017/2018 BRA through the 2021/2022 BRA suggests that Byron's and Quad Cities' inability to clear the market was caused by two primary factors, [redacted]

[16] Monitoring Analytics. August 24, 2018. *Analysis of the 2021/2022 RPM Base Residual Auction: Revised*. A report prepared by The Independent Market Monitor for PJM, page 3.

[17] Id, page 18. These include nuclear units in Ohio, Pennsylvania, and Illinois that did not clear the 2021/2022 Base Residual Auction.

[18] EXC Audit 11.

[redacted] and [redacted]. The experiences of the two plants provide some context to understand Exelon's historical PJM capacity market participation.

While all of Exelon's plants cleared the 2017/2018 BRA, and the subsequent capacity performance transition auction, Quad Cities failed to clear the 2018/2019 auction [redacted]

Another reason for some plants not clearing is [redacted]

[redacted].

When modeling future years, we have assumed that all Exelon nuclear power plants in the PJM COMED zone will bid at low prices with the intention to clear the capacity market. This strategy would ensure that each plant receives full capacity revenues for each unit's entire firm capacity.

Other revenues

Other revenues such as ancillary services compensation represent the smallest portion of total revenues for the six nuclear plants.

---

[19] PJM Interconnect. September 17, 2020. PJM Open Access Transmission Tariff. Attachment DD Section 5.12.

[20] EXC Audit 44.

[21] EXC Audit 44.

1.3. Separation of Exelon

On February 24, 2021, Exelon announced its intention to separate its utility and competitive energy business into two separate companies.[22] We understand that the split will separate the six regulated electric and gas utilities from the competitive generation and energy businesses. Exelon expects the separation to be completed by the first quarter of 2022, subject to regulatory approvals.[23] At this time, we do not have any specific information about the nature of the separation or how the separation will impact the operations of the nuclear plants. Accordingly, we have not made any specific adjustments in our analyses.

2. METHODOLOGY

Generally, nuclear plant financial analyses entail settling on a portfolio of uncertain assumptions, which then form the basis of linear trajectories to determine future revenues and costs. This approach places undue importance on those initial choices. The result has led to contentious debates over study timeframes, the appropriateness of assumptions, treatment of uncertainties, and the magnitude of future risks. As an example, determining cost adders necessarily treats operational and market risk as fixed, when in fact these fluctuate over time as circumstances change. We find that various outcomes impacting the future profitability for a nuclear plant are hard to solve directly.

To better account for uncertainties and variable outcomes, we incorporated a Monte Carlo simulation that encompassed distribution and probabilities of revenues and costs for the four plants over the next five and 10 years rather than assigning fixed estimates for revenues and costs. The Monte Carlo simulation identified possible results by applying a probability distribution to inputs with inherent uncertainty. Our Monte Carlo simulation then recalculated results 10,000 times, each time using a different set of inputs randomly selected from within minimum and maximum values for our inputs. The simulation then developed a distribution of net present values (NPV) for each of the four plants for the analysis period using Exelon's discount rate of [redacted] percent without a subsidy and a Synapse discount rate of [redacted] percent with a subsidy. The following section details our Monte Carlo analysis methodology and our EnCompass modeling methodology to develop energy and capacity price inputs for the Monte Carlo analysis.

[22] Exelon. Exelon to Separate its Utility and Competitive Energy Businesses into Two Industry-Leading Companies. February 24, 2021. Available at https://www.exeloncorp.com/newsroom/exelon-to-separate-its-utility-and-competitive-energy-businesses-into-two-industry-leading-companies

[23] Ibid.

2.1. Monte Carlo Analysis

Synapse utilized a Monte Carlo analysis to forecast the expected profitability of the four Exelon nuclear generating stations under a range of market and operational uncertainties. A Monte Carlo model is a mathematical technique used for evaluating possible outcomes in problems with uncertainty and risk. It is commonly employed in financial modeling and long-term prediction where the likelihood of various outcomes in a problem is difficult to resolve with any certainty. Our Monte Carlo analysis involved four steps:

1. Develop a predictive model for estimating an outcome (or result)—such as nuclear plant profitability—based on a range of inputs (or predictors).

2. For each input, identify the range and probability of possible values. This may be done using historical data, expert judgement, scenario-based assumptions, or a combination of these methods.

3. Run the predictive model, calculating the outcome based on input values selected at random from the range of possible values. Repeat this simulation many times to produce a large number (*e.g.*, many thousands) of likely outcomes until the distribution of outcomes does not change substantially with additional runs.

4. Evaluate the results of the simulation in order to estimate the likely outcome (*e.g.*, average of all simulations) and impact of uncertainty (*e.g.*, variance, range, or probability of simulated values).

In short, a Monte Carlo analysis identifies possible results by applying a probability distribution to inputs with inherent uncertainty. The simulation recalculates results numerous times, each time using a different set of inputs randomly selected from within minimum and maximum values.

Synapse's approach fits within a history of previous studies that have used Monte Carlo methods to evaluate the financial viability of nuclear power stations under a range of technical, economic, and policy uncertainty. For example, Wealer et al.[24,25] evaluated economic indicators of current and future investments in construction and operation of nuclear power plants through Monte Carlo simulations. A 2017 study by Riesz et al.[26] assessed the economic risks for nuclear power generators using Monte Carlo modeling to quantify the combined effect of uncertainty across a range of nuclear plant cost

[24] Wealer, B., Bauer, S., Göke, L., Hirschhausen, C. and Kemfert, C., 2019. *Economics of nuclear power plant investment: Monte Carlo simulations of generation III/III+ investment projects.* Deutsches Institut für Wirtschaftsforschung.

[25] Wealer, B., Bauer, S., Hirschhausen, C., Kemfert, C. and Göke, L., 2021. "Investing into third generation nuclear power plants-Review of recent trends and analysis of future investments using Monte Carlo Simulation." *Renewable and Sustainable Energy Reviews*, *143*, p.110836.

[26] Riesz, J., Sotiriadis, C., Vithayasrichareon, P. and Gilmore, J., 2017. "Quantifying key uncertainties in the costs of nuclear power." *International Journal of Energy Research*, *41*(3), pp.389-409.

components. Rode et al. (2001)[27] presented a case study comparing the valuation of an existing nuclear plant using a standard income-capitalization analysis and a Monte Carlo simulation.

Synapse's Monte Carlo model is designed to capture the impact of market and operational uncertainty on the economics of Exelon's power plants. This approach is an alternative to Exelon's method of characterizing economic risk. When assessing the future economic viability of its nuclear generating stations, Exelon incorporates an estimate of market and operating risk alongside its forecasted annual operating expenses of each plant. [redacted] our Monte Carlo analysis identifies a range of probable NPVs, inclusive of uncertainty in expenses (for example, due to unscheduled outages, unplanned capital projects, and variations in operating costs) and revenues due to market fluctuations.

Methodology for simulating of nuclear plant NPV cash flows

The Monte Carlo model is designed to perform 10,000 simulations for each plant, outputting a single estimate of the plant's NPV for each simulation. The NPV provides a measure of profitability by aggregating projected revenues and expenditures at a plant over multiple years, with cash flows in future years discounted by a weighted average cost of capital (WACC). Equation 1 provides the formula for calculating NPV, where C_t represents the net-cashflows at a plant at time t, and r is the WACC or discount rate. It is important to draw a distinction between net cashflow and net income. The former is a measure of the actual cashflow associated with a plant in a year, while the latter takes accrual schedules into account and is only impacted by the recognized incomes and expenses for a given period. Functionally, this means that net cash flow includes all capital expenditures, whereas net income would only include depreciated or amortized capital. The discount factor [redacted] is calculated using Exelon's methodology.[29] The exponential term [redacted] represents the time elapsed since January 1, 2021, as of the start of the third quarter (July 1st) in each year.

[redacted]

[redacted]

Plant revenues are primarily generated through the energy market and capacity market, though our model also includes ancillary service revenue. At a high level, expenditures consist of five categories of

---

[27] Rode, D.C., Fischbeck, P.S. and Dean, S.R., 2001. "Monte Carlo methods for appraisal and valuation: a case study of a nuclear power plant." *The Journal of Structured Finance*, *7*(3), pp.38-48.

[redacted]

[29] EXC Audit 24.

cost: operations and maintenance (O&M), overhead, outage, spent fuel, and capital expenditures on fuel and non-fuel items. The random variation within the Monte Carlo is modeled independently for many, though not all, of the revenue and expense parameters. After this, the model aggregates net cashflows and calculates an NPV. For a more detailed description of the methods used to calculate revenues and expenses and to estimate the associated uncertainty, see reference Appendix F.

Data inputs

The Synapse Monte Carlo simulation estimated the NPV of each nuclear generating station using a combination of inputs (1) provided by Exelon through discovery and (2) independently prepared by Synapse. Figure 6 summarizes the input categories and uncertainty distributions we used to estimate plant-specific revenues and expenses over the study period. We used Exelon's expected plant operations and expenses for initial cost inputs to our model. However, we replaced Exelon's forecasted energy and capacity revenues using results from our own modeling of the PJM and MISO markets, as described in Section 2.2. To directly quantify the effect of future market and operational uncertainty, we incorporated two types of adjustments to our model parameters:

1. Adjustments to Exelon's forecasted operations, revenues, and expenses where these parameters do not include the impact of operational risk. [redacted]
2. Additionally, we defined a range of possible values for inputs that can significantly impact total revenues and expenses. We create these ranges and associated probability distributions using historical data provided by Exelon[30] or scenario-based assumptions.[31]

Appendix F provides time-variant granular data at the plant level used in the Monte Carlo analysis and a detailed description of the methods used to prepare the uncertainty distributions.

[30] For example, we used 10 years of historical unscheduled plant outage data provided by Exelon in discovery response to create a fleet-wide probability distribution of forced outage events and their associated durations.

[31] For example, we created an assumed probability distribution that the U.S. Department of Energy revives the nuclear spent fuel fee in the future.

Figure 6. Data inputs and uncertainty distribution for Monte Carlo analysis

Input Category	Include Exelon Values	Include Synapse Values or Adjustments	Model Uncertainty in Monte Carlo Analysis	Uncertainty Distribution
Energy Revenue	No	Yes	Yes	Probabilistic (non-uniform); based on 10-year historical distribution of PJM bus-level prices; incorporates uncertainty in generation based on 10-year Exelon historical outage distribution
Capacity Revenue	No	Yes	Yes	Normal; based on Synapse sensitivity analyses of PJM capacity market
ZEC Revenue	Yes	Yes	Sensitivity analysis	$0/MWh – $16.5/MWh
Ancillary Revenue	Yes	No	No	N/A
O&M Expenses	Yes	Yes	Yes	Probabilistic (non-uniform); based on 10-year historical distribution of Exelon O&M costs, including unscheduled outages
Capital Expenses	Yes	Yes	Yes	Probabilistic (non-uniform); based on 10-year historical distribution of Exelon capital costs from outages
Outage Expenses	Yes	Yes	Yes	Probabilistic (non-uniform); based on 10-year historical distribution of Exelon scheduled outage costs
Nuclear Fuel Expenses	Yes	No	No	N/A
Spent Fuel Expenses	Yes	No	Yes	Binary (0 or 1) multiplier with a probability function for value of 1 that grows at 3% per year starting at 0% for 2021, representative of U.S. DOE reviving the spent nuclear fee in the future
Overhead Expenses	Yes	No	Yes	Probabilistic (non-uniform); based on 10-year historical distribution of Exelon overhead costs
Discount Rate	Yes	Yes	Sensitivity analysis	Synapse ([redacted]) or Exelon ([redacted])

Monte Carlo sensitivity and scenario analysis

Utilizing a Monte Carlo simulation allowed us to evaluate the sensitivity of Exelon's nuclear plant profitability to possible future scenarios and different study periods. We estimated the NPV for each plant across a series of sensitivities and scenarios:

- **ZEC Rates:** Although our Monte Carlo was not designed as an optimization model, it does include a sensitivity analysis which reports projected NPVs at 15 levels of ZEC subsidy. The sensitivity analysis can be used to identify the subsidy amount to ensure positive NPVs at each plant. The first ZEC scenario was for a $0.0/MWh ZEC, which simulates a business-as-usual scenario in which the plants receive no additional revenue from ZEC subsidies. The next 12 scenarios analyzed ZECs ranging from $0.5/MWh to $6.0/MWh, separated by increments of $0.5/MWh. Additionally, we modeled a $10.0/MWh subsidy and a $16.5/MWh ZEC subsidy to test the effects of larger ZECs on plant NPVs. The lowest ZEC amount for which 95 percent of all Monte Carlo simulations were positive was determined to be the required subsidy for each plant.

- **Discount rate**: Our model computed plant NPV under two discount rates. Our base assumption for discount rate used Exelon's current after-tax WACC of [redacted].[32] We also included a [redacted] percent discount rate to represent returns to shareholders for a lower-risk investment, such as nuclear plants supported by ZECs or other subsidies to help maintain profitability. [redacted][33]

- **Carbon price**: We evaluated plant profitability under scenarios with and without carbon pricing. Our baseline model incorporated expected plant revenues within the PJM and MISO markets under a business-as-usual policy scenario in which carbon pricing has not been adopted. To test the effect of carbon pricing, we used an alternate forecast of plant revenues in which Illinois implements a carbon price comparable to Regional Greenhouse Gas Initiative (RGGI) carbon prices in year 2023.

- **Study Periods:** We calculated NPV over a 5-year and 10-year study period to evaluate whether the need for a subsidy varies with time. The model first estimated variation over the full 10-year study period, which runs from 2021 to 2030. When NPVs of the cash flows were calculated during the final step of each simulation, the model either took the full 10-year time series of net-cash flow data or just the first five years, depending on which study period NPV it was calculating. While most of the plants are fully operational throughout the entire 10-year study period, Dresden has its nuclear licenses expire before the end of 2030. The license for Dresden Unit 2 will expire in December 2029, which primarily impacts net cash flows during the final years of the 10-year study period. Exelon has not announced any plans to extend the license for Unit 2 beyond 2029.

---

32 [redacted]

33 Exelon. Earnings Conference Call Fourth Quarter 2020. February 24, 2021. See slide 33. Available at https://investors.exeloncorp.com/static-files/2dda3a5d-b5c9-40d6-829f-da5c2efd6cc9.

2.2. EnCompass Modeling

We modeled energy and capacity prices for the nuclear plants using the EnCompass production-cost model for (a) a base-case scenario that assumes the nuclear plants retire based on current nuclear license expirations and (b) a carbon-price scenario that introduces a carbon price in Illinois in 2023. We then used the resulting energy and capacity price forecasts as inputs into the Monte Carlo analysis. The following describes our modeling methodology. Appendix E provides more detailed information regarding the EnCompass model inputs incorporated in our analysis.

EnCompass Model

Synapse used the EnCompass model to derive both energy and capacity prices at a zonal level for the MISO and PJM regions. Developed by Anchor Power Solutions, EnCompass is a single, fully integrated power system platform that allows for utility-scale generation planning and operations analysis. EnCompass is an optimization model that covers all facets of power system planning, including the following:

- Short-term scheduling, including detailed unit commitment and economic dispatch
- Mid-term energy budgeting analysis, including maintenance scheduling and risk analysis
- Long-term integrated resource planning, including capital project optimization and environmental compliance
- Market price forecasting for energy, ancillary services, capacity, and environmental programs

EnCompass provides unit-specific, detailed forecasts of the composition, operations, and costs of the regional generation fleet given the assumptions described in this document. Synapse populated the model using the *EnCompass National Database*, created by Horizons Energy. Horizons Energy benchmarked its comprehensive dataset across the 21 North American Electric Reliability Corporation (NERC) Assessment Areas and it incorporates market rules and transmission constructs across 76 distinct zonal pricing points. More information on EnCompass and the Horizons dataset is available at www.anchor-power.com.

Modeling topology

Exelon's Illinois nuclear units are located in the PJM-COMED and MISO Illinois zones. Synapse modeled the PJM and MISO regions to derive both energy and capacity prices at the zonal level for each of the respective balancing authorities and zones. Each zone is mapped to the regional projections for system demand and specific generating units are mapped to aggregated geographical regions. The load and generation within each of the zonal areas are then linked by transmission areas to create an aggregated balancing area. In addition, each of the balancing authorities is subject to renewable portfolio standards. The model integrates RGGI compliance for participating states. For further details on input parameters related to EnCompass modeling, please refer to Appendix E.

Scenario analysis

Synapse analyzed the impacts of two scenarios for energy prices, capacity prices, and carbon dioxide (CO_2) emissions. The results of these runs are outlined in Section 3.1 and Appendix H. The first scenario, or Baseline Scenario, modeled evaluated the energy price and capacity prices for a 10-year time frame under the assumption that all nuclear units will operate to the end of their current license expiration dates. The second scenario, or Carbon Price Scenario, maintained similar assumptions but also assumed that Illinois fossil fuel-based plants would be subject to a carbon price equivalent to RGGI prices starting in 2023 and that Pennsylvania joins RGGI in 2022.[34]

3. RESULTS: BYRON AND DRESDEN

3.1. Monte Carlo Analysis Results

Our simulations identified the range of possible NPVs for the future operation of Byron and Dresden.[35] The results represent a span of potential future market and operational conditions inclusive of Exelon's expected future expenses, Synapse's forecast of plant revenues, and a range of potential variation that is grounded in 10 years of operating experience and market data for Exelon's 11 Illinois nuclear units across six plant sites. We included scenarios (a) with ZEC values ranging from \$0–\$16.5/MWh, (b) with and without carbon pricing, (c) using 5-year and 10-year study periods, and (d) with the Synapse and Exelon discount rates. Figure 7 and Figure 8 present these NPV cash flows for Byron. Results for Dresden are shown in Figure 9 and Figure 10. Compared to Exelon projections found in its discovery responses, our estimates of NPV are higher, primarily due to the differences in energy and capacity revenues.

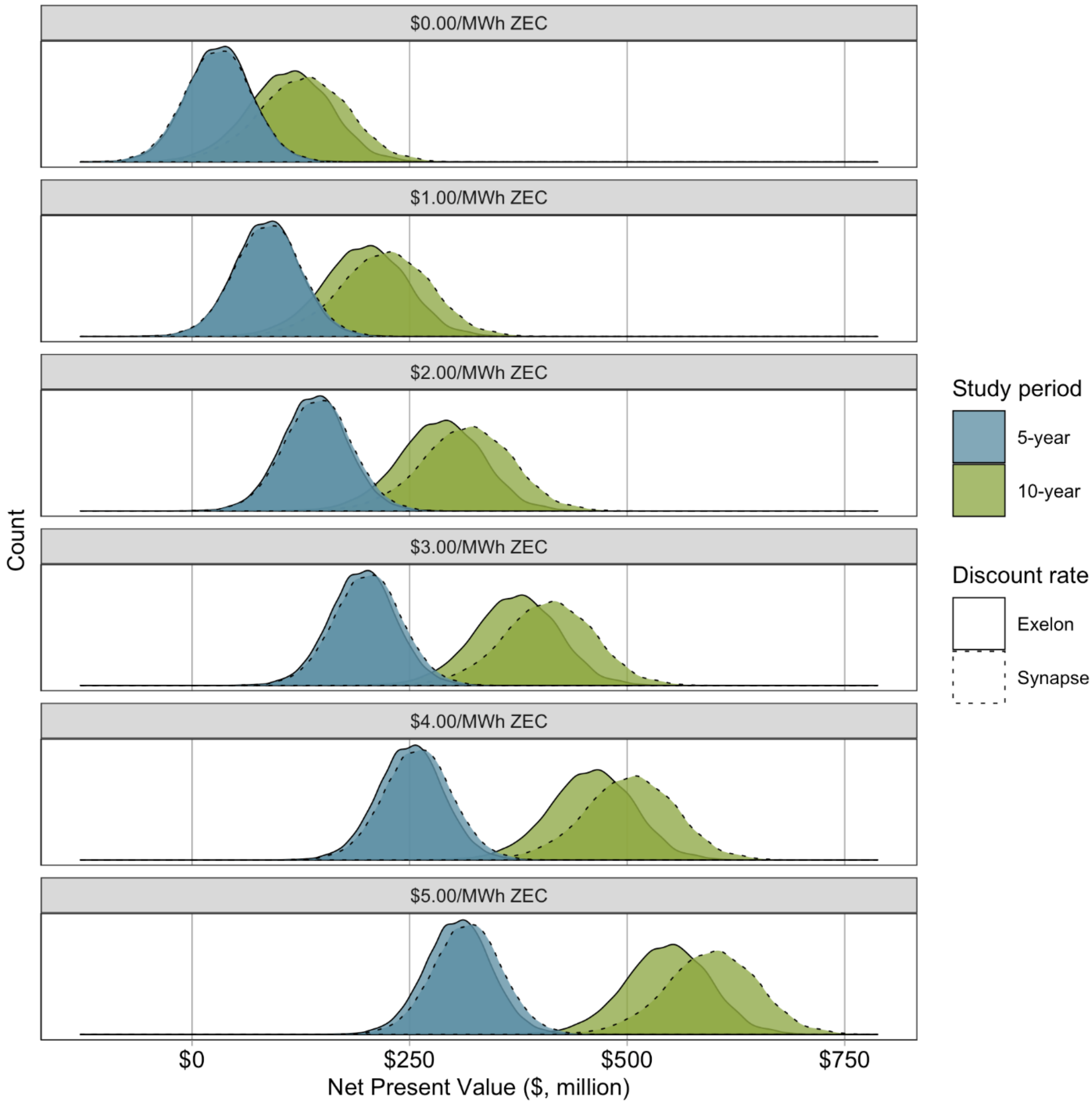
Our Monte Carlo analysis indicated that, in scenarios without carbon pricing, modest subsidies may be needed to ensure positive NPV cash flow in 95 percent of the iterations for the Byron and Dresden plants during the period 2021–2025. For simulations with a ZEC value of \$0/MWh, the bottom 20 percent, and 100 percent of economic outcomes for Byron and Dresden, respectively, had negative NPVs in the 5-year analysis with the Exelon discount rate. However, adding a ZEC price of \$1.0/MWh results in a positive 5-year NPVs for 95 percent of simulations for Byron. Similarly, a ZEC price of \$3.5/MWh was sufficient to create positive 5-year NPVs for Dresden in 95 percent of model runs. No subsidies were required to support Byron and Dresden when we expanded the Monte Carlo study period to the timeframe 2021–2030, as all simulations for both plants resulted in positive NPV cashflows. The scenario with carbon pricing results in positive NPVs for Byron, but negative NPVs for Dresden under the 2021–2025 study period. Additional Carbon Price Scenario results are presented in

[34] Pennsylvania Department of Environmental Protection. Regional Greenhouse Gas Initiative. "What's RGGI" 2021. Available at: https://www.dep.pa.gov/Citizens/climate/Pages/RGGI.aspx.

[35] Refer to Appendix G for Monte Carlo analysis results for Braidwood and LaSalle.

Appendix H. Taken together, these results suggest that a decision by the State of Illinois to provide modest (e.g., $1.0 and $3.5/MWh), short-term (e.g., 5-year) ZECs to Byron and Dresden may be sufficient to keep 95 percent of the expected NPVs positive. Further, a carbon price in the same range as RGGI, would maintain positive NPVs for Byron for 95 percent of the iterations and would reduce the subsidy for Dresden to $2.5/MWh to ensure that 95 percent of the Monte Carlo iterations are positive.

Figure 7. Byron net present value cash flow, Baseline Scenario—Monte Carlo simulations



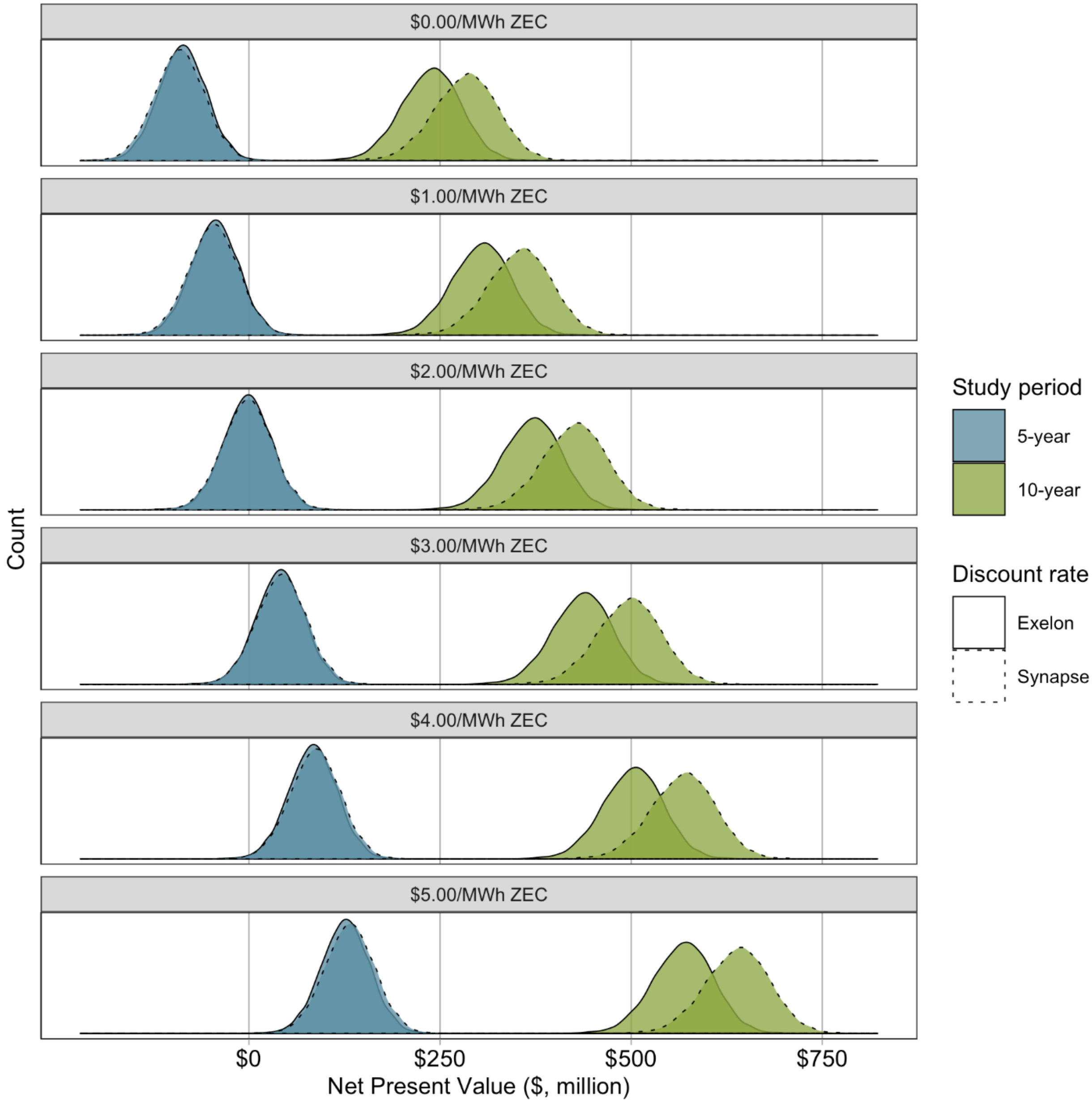
Source: Synapse Energy Economics model—Monte Carlo analysis using Exelon expense forecast with adjustments, Synapse energy and capacity revenues forecast (Synapse internal production cost and capacity expansion model), and uncertainty distributions derived from historical market and operational data.

Figure 8. Byron expected net present value cash flow, Baseline Scenario—Monte Carlo simulations ($, million) [5th–95th percentile]

ZEC	10-Year Study Period Monte Carlo NPV Results		5-Year Study Period Monte Carlo NPV Results	
($/MWh)	Synapse Discount Rate	Exelon Discount Rate	Synapse Discount Rate	Exelon Discount Rate
0.0	127 [40 - 210]	111 [30 - 188]	30 [-34 - 93]	31 [-30 - 92]
0.5	174 [87 - 257]	154 [73 - 231]	59 [-5 - 122]	58 [-3 - 119]
1.0	221 [134 - 304]	198 [117 - 275]	87 [23 - 151]	86 [25 - 147]
1.5	268 [180 - 352]	241 [160 - 319]	116 [52 - 180]	113 [52 - 175]
2.0	315 [227 - 399]	285 [203 - 362]	145 [81 - 208]	141 [79 - 202]
2.5	362 [274 - 446]	328 [247 - 406]	173 [109 - 237]	168 [107 - 230]
3.0	409 [321 - 493]	372 [290 - 449]	202 [138 - 266]	196 [134 - 257]
3.5	456 [368 - 540]	415 [333 - 493]	231 [166 - 295]	223 [161 - 285]
4.0	503 [414 - 587]	459 [377 - 536]	259 [195 - 324]	251 [189 - 313]
4.5	550 [461 - 634]	502 [420 - 580]	288 [223 - 352]	278 [216 - 340]
5.0	597 [508 - 681]	546 [464 - 624]	317 [252 - 381]	306 [243 - 368]
5.5	644 [555 - 728]	589 [507 - 667]	345 [280 - 410]	333 [271 - 395]
6.0	691 [602 - 775]	633 [550 - 711]	374 [309 - 439]	361 [298 - 423]
10.0	1,066 [976 - 1,152]	981 [897 - 1,060]	603 [537 - 669]	581 [517 - 644]
16.5	1,676 [1,585 - 1,764]	1,546 [1,461 - 1,626]	976 [908 - 1,043]	938 [873 - 1,003]

Source: Synapse Energy Economics model—Monte Carlo analysis using Exelon expense forecast with adjustments, Synapse energy and capacity revenues forecast (Synapse internal production cost and capacity expansion model), and uncertainty distributions derived from historical market and operational data.

Figure 9. Dresden net present value cash flow, Baseline Scenario—Monte Carlo simulations



Source: Synapse Energy Economics model—Monte Carlo analysis using Exelon expense forecast with adjustments, Synapse energy and capacity revenues forecast (Synapse internal production cost and capacity expansion model), and uncertainty distributions derived from historical market and operational data.

Figure 10. Dresden expected net present value cash flow, Baseline Scenario—Monte Carlo simulations ($, million) [5th–95th percentile]

ZEC	10-Year Study Period Monte Carlo NPV Results		5-Year Study Period Monte Carlo NPV Results	
($/MWh)	Synapse Discount Rate	Exelon Discount Rate	Synapse Discount Rate	Exelon Discount Rate
0.0	283 [213 - 350]	238 [172 - 300]	-91 [-145 - -38]	-87 [-139 - -36]
0.5	319 [248 - 386]	271 [205 - 333]	-69 [-123 - -15]	-66 [-118 - -14]
1.0	355 [283 - 421]	304 [238 - 366]	-47 [-101 - 7]	-44 [-97 - 7]
1.5	390 [319 - 457]	337 [271 - 399]	-24 [-79 - 29]	-23 [-76 - 29]
2.0	426 [354 - 493]	370 [303 - 432]	-2 [-57 - 52]	-2 [-54 - 50]
2.5	461 [390 - 528]	403 [336 - 465]	20 [-34 - 74]	20 [-33 - 71]
3.0	497 [425 - 564]	436 [369 - 498]	43 [-12 - 96]	41 [-12 - 93]
3.5	532 [461 - 600]	469 [402 - 531]	65 [10 - 119]	62 [10 - 114]
4.0	568 [496 - 635]	502 [435 - 564]	87 [32 - 141]	84 [31 - 136]
4.5	603 [532 - 671]	535 [468 - 598]	109 [55 - 163]	105 [52 - 157]
5.0	639 [567 - 706]	568 [501 - 631]	132 [77 - 186]	126 [73 - 178]
5.5	674 [602 - 742]	601 [534 - 664]	154 [99 - 208]	148 [95 - 200]
6.0	710 [638 - 778]	634 [567 - 697]	176 [121 - 230]	169 [116 - 221]
10.0	994 [922 - 1,063]	898 [831 - 962]	354 [298 - 409]	340 [286 - 392]
16.5	1,456 [1,382 - 1,526]	1,327 [1,259 - 1,392]	643 [586 - 699]	617 [562 - 671]

Source: Synapse Energy Economics model—Monte Carlo analysis using Exelon expense forecast with adjustments, Synapse energy and capacity revenues forecast (Synapse internal production cost and capacity expansion model), and uncertainty distributions derived from historical market and operational data.

The results of the Monte Carlo modeling indicate that both Byron and Dresden are expected to experience negative NPVs over the five-year study period and positive NPVs over the 10-year study period. [redacted]

Figure 11. Monte Carlo NPVs difference from Exelon NPVs

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]

The gap between Exelon's forecasts and the Monte Carlo results were caused by several aspects of the model, but differences in energy and capacity revenue forecasts were the biggest factors. Exelon's revenue forecasts are lower than those produced by the EnCompass model, which became the price inputs for the Monte Carlo model. [redacted] As a result, net cash flows were also lower in the Exelon forecasts than in the Monte Carlo analysis, which in turn led to lower NPVs.

In addition to the revenue differences, the Monte Carlo model contains several elements that likely contributed to the gap in NPVs. Two of these will tend to lead to lower costs than those projected in the Exelon forecasts. First, the spent fuel methodology, which factors in a reduced probability that spent fuel costs will be collected by the U.S. Department of Energy, likely eliminated spent fuel costs in many of the years included in both the five and 10-year study period. This is particularly true in the earliest years of the analysis, which are also the years with the largest impact on NPV. Second, the scheduled outage distribution in the Monte Carlo simulation was more heavily weighted towards shorter outage duration, meaning that Exelon is likely to complete scheduled outages more quickly than forecast. This depressed outage costs and allowed Exelon to increase generation. Although these two elements depress costs, there are other offsetting elements which may have contributed to increased costs. Namely, unscheduled outages will always lead to cost increases in the event that they occur. Ultimately, while the spent fuel and scheduled outage cost elements may have contributed to slight depression of costs, these factors were secondary to revenues in causing the NPV disparity between Exelon and the Synapse Monte Carlo analysis.

[redacted]

[redacted]

Our Monte Carlo analysis also incorporated Overhead costs attributable to the nuclear plants. Overhead costs are referenced in the 2016 Clean Energy Jobs Act that established the current Illinois ZECs. Other states have also included fully allocated overhead costs in their evaluation of nuclear plant financials. For the purposes of this analysis to be consistent with current CEJA legislation and consistent with Exelon's financial analyses, we have included these costs.[36] These costs include service company and corporate overhead costs. At this time Exelon has indicated that it [redacted] that overhead or service company costs will [redacted] when Exelon splits into two separate entities.[37]

Risk

The Illinois ZEC legislation and other similar ZEC legislation have included the phrase: "the cost of operational and market risk that could be avoided by ceasing operation." ZEC Applicants have interpreted the requirement by including adders for both operational and market risk to quantify the impact of lower revenues and/or higher costs. The use of the adders, in effect, assumes that there is a 100% probability that the plants will face both higher costs and lower revenues.

Our Monte Carlo analysis diverges from this absolute certainty of the operational and market risk by attempting to quantify the range and distribution of possible outcomes (negative and positive) for the nuclear plants.

3.2. Encompass Modeling Results

Figure 12 and Figure 13 below show the modeled energy and capacity prices for the COMED region. Figure 13 compares the modeled energy prices to the implied prices provided by Exelon for each of the plants.[38] The key drivers behind the modeled energy prices were the future coal and natural gas prices. The ComEd region energy price projections were also impacted by the commissioning of two large natural gas plants, which are expected to start operation within the next three years. The Jackson Generation and Three Rivers Energy Center plants are expected to start operation in 2022 and 2023,

[36] We recognize that overhead costs would be unavoidable for an entity should it retire a specific plant, and that such overhead costs would be reallocated to remaining plants within the portfolio. We would agree that an analysis of plants owned by different entities should only compare avoidable costs.

[37] Exe Audit 85.

[38] The implied energy price is based on energy revenues divided by generation.

respectively.[39] In addition, the marginal energy prices were impacted by renewable portfolio standard requirements and availability of lower cost energy resources such as solar and wind in PJM and MISO. The energy forecasts below represent the zonal energy and capacity prices at the PJM-COMED and MISO-IL zones, respectively.[40] For more details on the input assumptions associated with the modeling, see Appendix E.

[redacted]

Source: Exelon pricing forecasts and Synapse internal production cost and capacity expansion model.

The Synapse capacity price projections are shown in Figure 13. Note that the x-axis labels each delivery year. In recent years, prices in the COMED locational delivery area have been higher than prices in the broader PJM regional transmission organization (RTO) due to import constraints into the COMED locational delivery area. Going into the 2022–2023 delivery year, we project that prices in the COMED zone will no longer separate from the PJM RTO prices due to an increase in transmission capability, a decrease in the load forecast, and the availability of new supply resources in the locational delivery area.

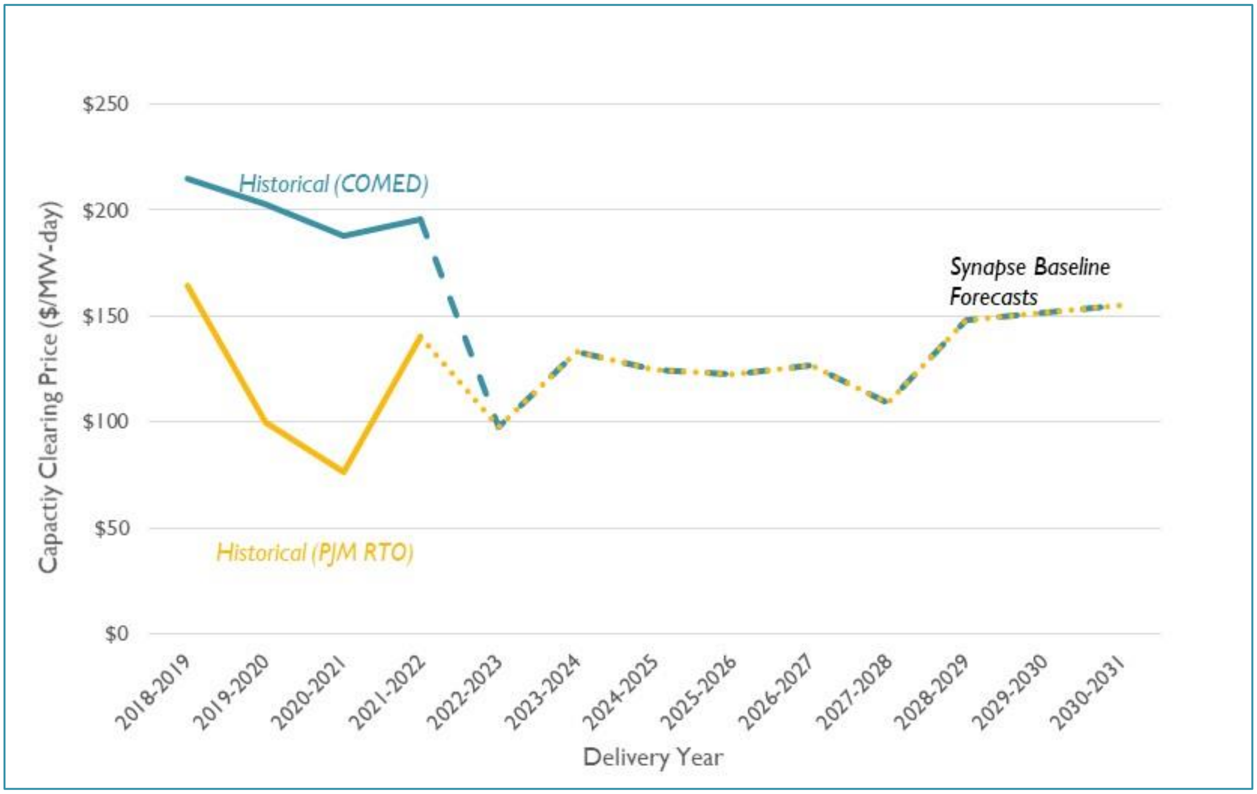
---

[39] Jackson Generation: https://jacksongeneration.com/ and CPV Three Rivers Energy Center: https://www.cpv.com/our-projects/cpv-three-rivers/.

[40] The Exelon energy prices also are at the bus level; thus they are generally lower than the COMED zone price presented in the figure. Synapse's Monte Carlo analysis adjusts for the bus price at each plant.

This is likely to cause a decline in capacity prices in the near term. In the longer term, we expect PJM RTO/ COMED capacity prices to slowly rise.

Figure 13. Historical and Synapse Capacity Price Forecasts for PJM-COMED and PJM RTO by Delivery Year



Source: Exelon pricing forecasts and Synapse internal production cost and capacity expansion model.

In addition to the Baseline Scenario, Synapse modeled a Carbon Price Scenario to use as an input to the Monte Carlo analysis that was conducted as an alternative to the Baseline Scenario. Figure 14 and Figure 15 below show the comparison of the energy and capacity prices in the PJM-COMED regions between the Baseline Scenario and the Carbon Price Scenario. The key drivers behind the energy prices for both scenarios remain the same, however the scenario with a carbon price implemented in Illinois starting in 2023 results in the higher clearing prices within the zone. For further details on the carbon pricing modeling assumptions, please refer to modeling assumptions in Appendix E.

Figure 14. Energy price comparison for Baseline and Carbon Price scenarios

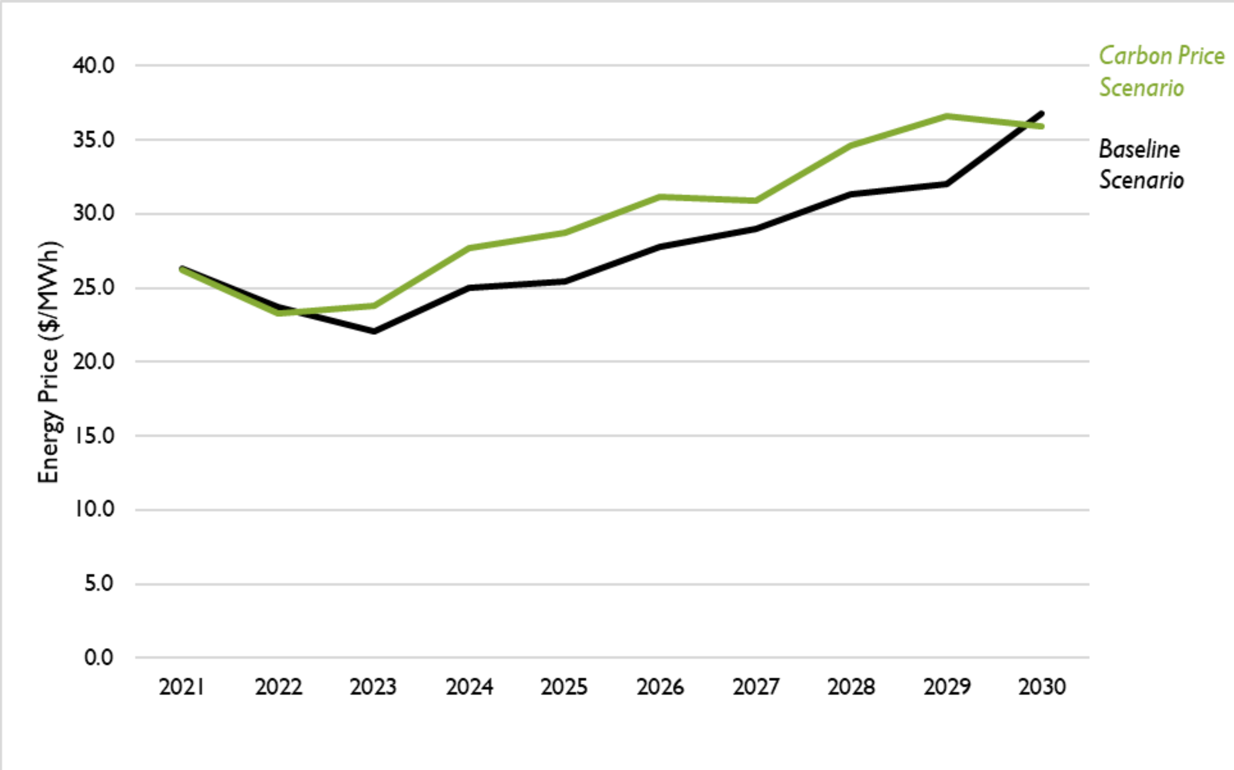


Figure 15 shows that the carbon price, while increasing energy prices in the COMED zone, does not have a large long-term impact on capacity prices. In the near term, however, there are fluctuations in the capacity price in the Carbon Price Scenario relative to the Baseline Scenario. The most notable impact is a reduction in capacity prices in the 2024-2025 delivery year. This is primarily a result of the carbon price modeled in Pennsylvania, which increases energy prices in that region and causes several large nuclear plants to offer capacity at lower bid prices. The additional low-cost capacity reduces capacity prices across the entire PJM RTO.

Figure 15. Capacity price comparison for Baseline and Carbon Price scenarios by delivery year

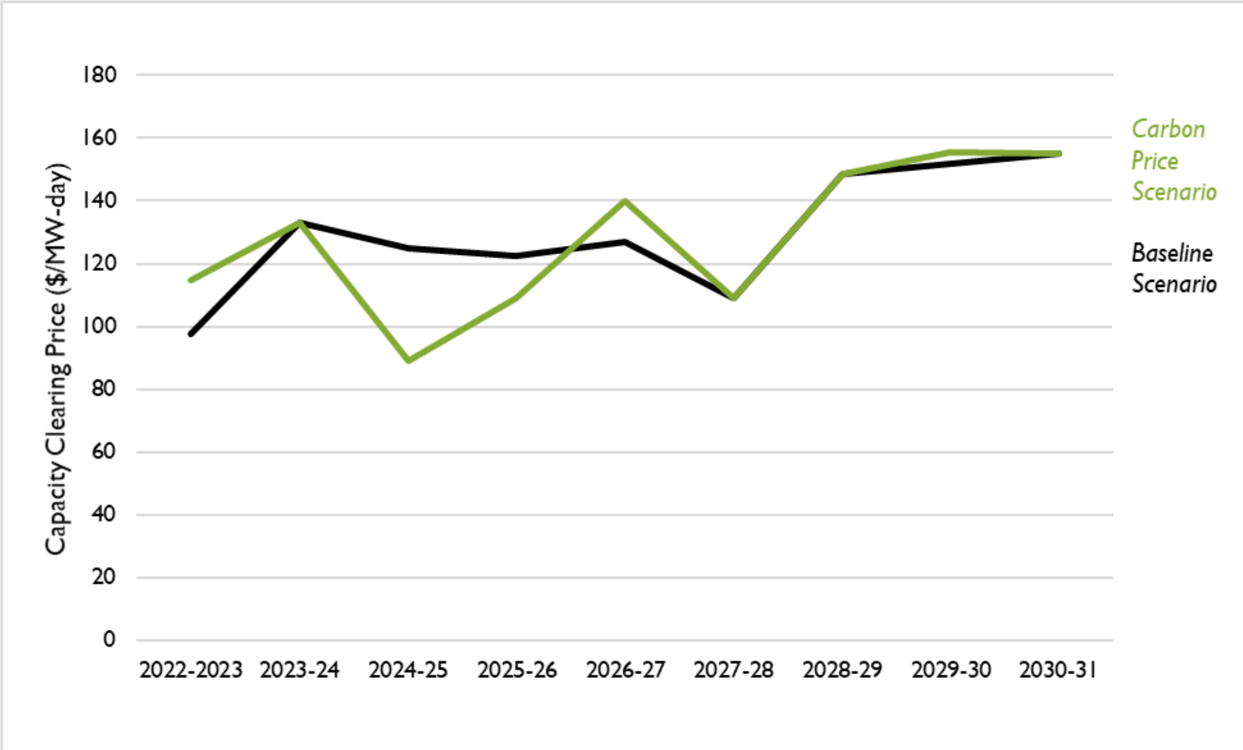
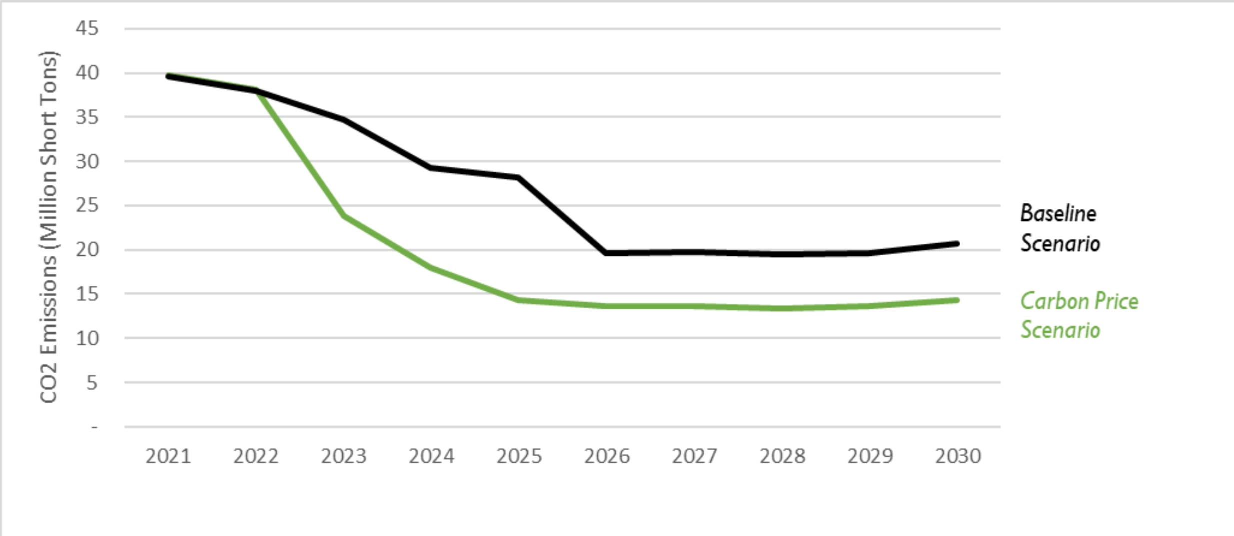


Figure 16 below shows the EnCompass modeled annual carbon emissions for Illinois, inclusive of units in both the MISO and PJM zones. The reduction in carbon emissions between the scenarios are driven by endogenous coal retirements in each of the scenarios. Coal units retire in the earlier years in both scenarios. The retirement of the coal plants in MISO's Illinois zone is more accelerated in the carbon pricing scenario, which results in an overall reduction in emissions. For units that remain online, there is some shift of generation from the coal plants to natural gas plants, which also results in reduced emissions.

Figure 16. Modeled Annual carbon emissions in Illinois



4. RECOMMENDATIONS

As a private entity, Exelon will have profitable years and unprofitable years. Exelon is not regulated by the Illinois Commerce Commission, so the state does not have an obligation to ensure that Exelon shareholders have an opportunity to realize a return each year on their investment in the plants. That said, our analysis demonstrates that Byron and Dresden do face real risk of becoming uneconomic in the near term. This has implications for Illinois's policy goals because the plants generate carbon-free electricity that is currently undervalued or even ignored within current wholesale electricity markets. In addition, the plants employ hundreds of workers directly and contribute to the economies of numerous Illinois communities. Illinois could reasonably determine that it is in the public interest for the plants to remain in operation, warranting public support.

State support of the Exelon nuclear power plants could help provide certainty for the plants through the period of anticipated risk. [redacted]. State support could be part of a strategy for the Illinois economy to transition to less carbon-emitting resources. To structure the support efficiently, state support would require cooperation from Exelon to be transparent with its finances to ensure that state support is provided only when required.

The results of our Monte Carlo analysis indicate that the five-year expected NPVs for three of the four plants are anticipated to have positive expected values based on our projections of revenues, costs, risks, and uncertainty. Only Dresden has a negative expected NPV in our five-year analysis. Byron has a positive expected NPV, but the 5th percentile value is -$34 million.

Synapse recommends:

If Illinois determines it is in the interest of state public policy to support the existing nuclear plants, then Synapse recommends that Illinois develop a program that offers financial support for the Byron and Dresden plants only when the plants require this support to ensure economic operation. Such a program should include the following features:

- This program need not extend beyond five years and could be re-evaluated at the end of the five-year period. The 10-year expected NPVs for Byron, LaSalle, and Braidwood are all positive. The 10-year NPV for Dresden is also positive. In our analysis, we assume Dresden Unit 2 retires in 2029, since Exelon has not announced any plans to extend the current license.
- Illinois could consider of a subsidy rate of $1.00/MWh for Byron and $3.50/MWh for Dresden that would ensure that 95 percent of the five-year expected NPVs for each plant remains above zero at the Synapse discount rate in the Monte Carlo analysis. For illustrative purposes, a $3.00/MWh rate would collect approximately $100 million per year from ratepayers for the two plants.
- Alternatively, if Illinois adopts a carbon price, the State could consider a subsidy rate of $2.50/MWh for Dresden only that would ensure that 95 percent of the five-year expected NPVs for each plant remains above zero at the Synapse discount rate in the Monte Carlo analysis. No subsidy would be required for Byron in the Carbon Price Scenario.
- While Synapse recommends no particular mechanism, any subsidy for the output of the two plants should be based on each plant's financial need. No subsidy should be paid without demonstration of actual need. Such need could be determined by either actual costs and revenues or based on projected energy prices relative to the projections developed in this analysis. This process should occur annually and should be transparent and formulaic for all parties.
- [redacted]: (See Appendix D for an explanation of these optimization efforts.)
  - [redacted]
  - [redacted]
  - [redacted]

Appendix A. CURRENT ILLINOIS ZERO EMISSION CREDITS

In 2016, the Illinois legislature passed Public Act 99-0906[41] (the Act) that created the Zero Emissions Standard. This policy awarded ZECs to select nuclear facilities beginning in 2017.[42] The Act required Illinois utilities[43] to purchase a set amount of ZECs until the end of the 10-year contract, subject to cost caps.

The Illinois Power Agency (IPA) is tasked with procuring a fixed amount of ZECs each year on behalf of Illinois utilities, which the utilities are then required to retire each year.[44] The annual target procurement quantity of 20,118,672 ZECs is a fixed amount. It reflects 16 percent of the actual amount of electricity delivered to retail customers in the state in 2014 for both Ameren & Commonwealth Edison, and 16 percent of the portion of power and energy procured by the IPA for MidAmerican Energy Company.[45] The target procurement quantity applies every year from 2017 until the end of the contract in 2027, subject to cost caps. The price of each ZEC is predetermined through the Act and is set at $16.50/MWh. This number represents the Social Cost of Carbon on a per MWh basis, based on the U.S. Interagency Working on Social Cost of Greenhouse Gases.[46] The price is set to rise by $1.00 each year beginning in 2023 through 2027, subject to cost caps.

The Act instructed the IPA to procure contracts with zero-emission facilities that demonstrated reasonable capability to generate cost-effective ZECs in an amount equal to the target procurement quantity. As such, qualified zero-emission facilities intending to participate in the procurement event were required to submit a bidder eligibility form along with exhibits that showed (i) remaining useful life of the units, (ii) historical energy generation, and (iii) facility cost projections including fully allocated overhead costs, cost of operational and market risk, spent nuclear fuel, and more.

The procurement event was held in early 2018, and the winning supplier was chosen based on a scoring mechanism developed by the IPA to ensure the selected units met the public interest criteria specified in

[41] *Public Act 099-0906, Illinois General Assembly.* 2017. Available at: https://www.ilga.gov/legislation/publicacts/99/PDF/099-0906.pdf.

[42] A ZEC is a tradable credit that represents the environmental attributes of one megawatt-hour (MWh) of energy produced from a zero-emission facility.

[43] Specifically, Ameren Illinois, Commonwealth Edison, and MidAmerican Energy.

[44] *Zero Emission Standard Procurement Plan, Illinois Power Agency*. 2017. Available at: https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/Zero-Emission-Standard-Procurement-Plan-ICC-Filing.pdf.

[45] Illinois Commerce Commission. 2019. *Report on ICC's review of the ZEC procurements*. Available at: https://www.ilga.gov/reports/ReportsSubmitted/553RSGAEmail1216RSGAAttach2019%20Report%20to%20General%20Assembly%20in%20Compliance%20with%20Section%201-75(d-5)%20IL%20Power%20Agency%20Act.pdf.

[46] Illinois Power Agency. 2017. Page 16.

the Act. These criteria are mainly geared toward the minimization of CO_2, sulfur dioxide (SO_2), nitrogen oxides (NO_X) and particulates (PM).[47] Exelon's Clinton and Quad Cities plants received the highest scores.

Two mechanisms currently exist to protect ratepayers from substantial increases in their electric bills because of the Zero Emission Standard.[48] First, the price of the ZECs outlined in the Act is subject to a market price adjustment. This allows the price of the ZEC to be reduced if a set of indices for the applicable year exceeds the 2015/2016 Baseline Market Price index of $31.40/MWh. Since 2017, the market price adjustment clause has not been triggered.

Second, the quantity of ZECs to be procured each year is subject to a Zero Emission Cost Impact Cap that limits the amount of ZECs that can be procured each year to ensure that ZEC costs to retail customers comprise no more than 1.65 percent of the amount paid per kWh by eligible retail customers during the year ending in 2009. The Zero Emission Cost Impact Cap therefore creates a procurement budget each year. Below, we provide the calculation for each utility for the 2017–2018 delivery year.

(1.65% * 2008-2009 Rate for Eligible Retail Customers) * 2016–2017 kWh to all retail customers

- Ameren Illinois: (1.65% * 10.77 cents/kWh) * 35,886,827MWh = $63,748,017
- ComEd: (1.65% * 11.82 cents/kWh) * 88,075,281MWh = $171,817,027
- MidAmerican: (1.65% * 6.18 cents/kWh) * 263,664 MWh = $268,705

These ZEC cost caps are then further reduced by the costs incurred by the utilities to retire the ZECs as added to any other administrative costs associated with the purchase of ZECs. For every year since the 2017–2018 delivery year, the target procurement quantity has exceeded the procurement budget, resulting in accumulating unpaid contractual volumes. The Act specifies that unpaid contractual volumes are "banked." In other words, Exelon can be compensated for these volumes in succeeding delivery years where the target procurement amount does not exceed the procurement budget. However, any unpaid contractual volumes at the end of the contract term will not be compensated according to the Act. Synapse projects that the target procurement quantity will likely continue to exceed the procurement budget for every year until the end of the contract. Figure 17 and Figure 18 show ZEC procurement budgets and contractual differentials, respectively, for each delivery year to date.

---

[47] Illinois Commerce Commission. 2018. *Public Notice of Successful Bidders*. https://www.ipa-energyrfp.com/?wpfb_dl=1450.

[48] Illinois Commerce Commission. 2019. *Report on ICC's review of the ZEC procurements.* https://www.ilga.gov/reports/ReportsSubmitted/553RSGAEmail1216RSGAAttach2019%20Report%20to%20General%20Assembly%20in%20Compliance%20with%20Section%201-75(d-5)%20IL%20Power%20Agency%20Act.pdf.

Figure 17. Historical ZEC procurement calculation by delivery year

Metric	2017-2018	2018-2019	2019-2020
Ameren Illinois (MWh)	3,842,415	3,804,121	3,952,267
ComEd (MWh)	10,375,844	10,380,533	10,444,443
MidAmerican (MWh)	15,128	16,773	15,898
Total ZECs Procured (MWh)	**14,233,387**	**14,201,427**	**14,412,608**
ZEC Payments ($M)	235	234	238

Source: Illinois Commerce Commission. 2019. Report on ICC's review of the ZEC procurements. https://www.ilga.gov/reports/ReportsSubmitted/553RSGAEmail1216RSGAAttach2019%20Report%20to%20General%20Assembly%20in%20Compliance%20with%20Section%201-75(d-5)%20IL%20Power%20Agency%20Act.pdf.

Figure 18. ZEC contractual differentials by delivery year

Metric	2017-2018	2018-2019	2019-2020
Total ZECs Procured (MWh)	14,233,387	14,201,427	14,412,608
Target Procurement Quantity (MWh)	20,118,672	20,118,672	20,118,672
Unpaid Contractual Volumes (MWh)	**-5,885,285**	**-5,917,245**	**-5,706,064**
Outstanding ZEC Payments ($M)	**-97**	**-98**	**-94**

Source: Illinois Commerce Commission. 2019. Report on ICC's review of the ZEC procurements. https://www.ilga.gov/reports/ReportsSubmitted/553RSGAEmail1216RSGAAttach2019%20Report%20to%20General%20Assembly%20in%20Compliance%20with%20Section%201-75(d-5)%20IL%20Power%20Agency%20Act.pdf.

Appendix B. ECONOMIC CONTRIBUTION TO LOCAL COMMUNITIES

The Byron and Dresden Nuclear Stations are material economic contributors to the communities in which they are located.[49] In addition to the direct jobs provided and taxes paid, spending by workers and related suppliers recycles within the community to multiply the economic impact. The effect of the closure of either Byron or Dresden on the surrounding communities is outside the scope of this analysis. However, our review of operating costs yielded three observations relative to the potential economic impact of potential plant closures:

- [redacted]
- Job losses may be mitigated through a voluntary early retirement option
- Property tax revenues cannot be forecast with certainty

Job reductions are occurring with or without plant closures

As of 2020, each of Exelon's six Illinois plants (Braidwood, Byron, Dresden, Clinton, LaSalle, and Quad Cities) employed [redacted] These plants are further supported [redacted] full-time equivalent (FTE) employees at Exelon's corporate offices.[51] From 2017 to 2020, the number of personnel at Exelon's Illinois plants [redacted]. In 2018, Exelon began centralization efforts [redacted] While this centralization accounts [redacted] According to Exelon, [redacted] positions from across all plants [redacted] However, the total number of FTE positions at the plants [redacted] over the same time period.[redacted] Thus, even when accounting for Exelon's centralization efforts, [redacted] We are not able to determine the extent to which [redacted] will continue, with or without plant closures.

[49] Harger, Brian *Economic Impact Analysis Byron Generating Station Exelon Corporation* (Northern Illinois University, October 2020) https://img1.wsimg.com/blobby/go/647075f2-dca8-4303-9a34-01e9745deb82/Byron%20Station%20-%20Economic%20Impact%202020%20(FINAL)-1.pdf; Harger, Brian *Economic Impact Analysis Dresden Generating Station Exelon Corporation* (Northern Illinois University, January 2020) https://savedresden.com/wp-content/uploads/2020/09/Dresden-Only-Study-Current-Community-Presentation.pdf.

[50] EXC Audit 7.

[51] EXC Audit 101.

[52] EXC Audit 7.

[53] EXC Audit 101.

[54] EXC Audit 7.

Figure 19. Number of personnel at Exelon's Illinois nuclear plants

[redacted]

Job losses may be mitigated through a voluntary early retirement option

Focusing on the two plants for which Exelon has announced closures, Byron employed [redacted] Dresden [redacted] Thus, the closure of both plants, without mitigation, would [redacted].

However, worldwide the nuclear energy sector faces a vast wave of imminent retirements; 36 percent of its workforce is 55 or older.[56] Prior cited economic analyses do not account for the potential that some affected employees may be transferred to other facilities or offered early retirement or buy-out packages.[57] [redacted][58] Offering Byron and Dresden employees who are over 50 a

[55] EXC Audit 102 and EXC Audit 103.

[56] *The Global Energy Talent Index Report.* 2021. (Airswift/Energyjobline) p. 75. https://www.getireport.com/.

[57] Harger, Brian. 2020. *Economic Impact Analysis Dresden Generating Station Exelon Corporation.* Northern Illinois University. p. 2; https://img1.wsimg.com/blobby/go/647075f2-dca8-4303-9a34-01e9745deb82/Byron%20Station%20-%20Economic%20Impact%202020%20(FINAL)-1.pdf.

[58] EXC Audit 100.

voluntary opportunity to retire [redacted].[59] [redacted] employed throughout the decommissioning process, [redacted]. If Exelon were to offer the voluntary early retirement option to employees at the remaining plants, [redacted]

Property tax revenues cannot be forecast with certainty

If Exelon closes Byron, Dresden, or both, it is reasonable to assume that the total each plant pays in property taxes to its local county would also be impacted. The property taxes paid by Exelon represent a substantial proportion of the budgets of local institutions such as schools, libraries, and fire departments.[60] However, it is unclear when those properties would be reassessed or to what degree their value would be decreased, resulting in lower tax revenues. For instance, in 2018, Exelon began the decommissioning process for the Oyster Creek Nuclear Generating Station in New Jersey. During this process, Exelon submitted the "Oyster Creek Generating Station - Post-Shutdown Decommissioning Activities Report" to the U.S. Nuclear Regulatory Commission. Exelon noted in the report that Oyster Creek did not make up a significant portion of the township's revenue and they expected only a small decrease in property taxes due to the closure.[61] [redacted] 10.[62] It is reasonable to assume a similar trajectory if Byron and Dresden were to close, but it is not possible to forecast when and to what extent these revenues will be reduced.

---

[59] See for instance, *Exelon Retirement Program* which provides for early retirement at age 50 with 10 years of service https://www.sec.gov/Archives/edgar/data/22606/000119312511030543/dex102.htm.

[60] Harger, Brian. 2020. *Economic Impact Analysis Dresden Generating Station Exelon Corporation.* Northern Illinois University. p. 13. https://savedresden.com/wp-content/uploads/2020/09/Dresden-Only-Study-Current-Community-Presentation.pdf.

[61] Letter, Exelon Generation to U.S. Nuclear Regulatory Commission (May 21, 2018) re: Oyster Creek Nuclear Generating Station – Post-Shutdown Decommissioning Activities Report, p. 36 https://www.nrc.gov/docs/ML1814/ML18141A775.pdf.

[62] See EXC Audit 109 and EXC Audit 110.

Appendix C. CAPACITY MARKET BACKGROUND

Overview

Generators located within PJM and MISO earn revenue through providing capacity. Load-serving entities are required in both jurisdictions to demonstrate that they have commitments from capacity resources to meet the peak demand of the customers they serve, plus a reserve margin. Capacity resources can be acquired by load-serving entities through different mechanisms, including through organized capacity markets.

Given constraints on the ability to transfer power between zone on a regional grid, capacity markets often require specific obligations for capacity resources located within certain geographic areas. In PJM, the Quad Cities,[63] La Salle, Braidwood, Byron, and Dresden nuclear plants owned by Exelon are part of the COMED locational delivery area. The Clinton plant is part of MISO's Zone 4.

The MISO annual capacity market is referred to as the Planning Reserve Auction (PRA). The PRA provides a voluntary mechanism for load-serving entities to meet resource adequacy requirements. It provides a market for load-serving entities to secure resources to meet its capacity obligations for the coming planning year. For example, the PRA offer window is open on March 26, 2021 and then is closed on March 31, 2021 for Planning Year 2021/2022. MISO posts the auction results on the 10th business day in April.

The PJM capacity market, known as the reliability pricing model (RPM), is designed to procure sufficient capacity resources to meet forecasted system load plus a reserve margin three years in advance. The RPM includes annual auctions for capacity resources, known as the base residual auction (BRA), held in May of each year. PJM also conducts three incremental auctions for capacity in between the annual BRAs. These incremental auctions allow for replacement capacity resource procurements as well as increases (procurement) and decreases (selling excess) in capacity resource commitments due to reliability requirement adjustments.

The last BRA that PJM conducted was in May of 2018 for the 2021/2022 Delivery Year. The BRA for the 2022/2023 Delivery Year, originally scheduled to be held in May of 2019, was postponed in anticipation of the Federal Energy Regulatory Commission's (FERC) ruling on PJM proposed market rule changes. These proposed changes were intended to allow capacity resources developed under state programs to participate in the capacity market while addressing alleged price suppression impacts. FERC ultimately issued its Minimum Offer Price Rule (MOPR) order on December 19, 2019. The MOPR order expands the application of minimum offer price floors to all resources that receive state subsidies, including nuclear

[63] Exelon owns a 75 percent stake in Quad Cities. The other 25 percent is owned by MidAmerican Energy and is a capacity resource in MISO.

units. FERC's November 12, 2020 order accepting two compliance filings related to PJM's reserve market and energy and ancillary services offset calculation cleared the way for PJM to commence its capacity market operations. PJM has established an aggressive schedule to conduct BRAs in succession every six months until it can return to an annual cycle in May of 2024 for the 2027/2028 Delivery Year.[64]

Methodology for capacity price projections

We used the EnCompass model to project capacity prices through 2030. EnCompass calculates capacity prices by simulating the capacity market. Each resource's simulated bid is calculated by subtracting net energy and ancillary service revenues from the resource's fixed costs that need to be recovered over the course of the year. These bids are then converted into a supply stack and EnCompass determines how many of the resources clear the capacity market based on an input capacity demand curve.

We modeled the capacity clearing price in both the PJM COMED zone in Illinois and in the broader PJM market. The model was calibrated against historical capacity price results for the 2019–2020, 2020–2021, and 2021–2022 BRAs. In each of these auctions, the COMED zone cleared at a higher price than the full PJM RTO price; and by precisely specifying load forecast, demand curve, transmission constraint, and supply parameters, we observed this price separation in our model runs.

We modeled future capacity clearing prices by incorporating PJM's most recent peak demand forecasts for COMED as well as updated transmission import capability and demand curve parameters (such as the installed reserve margin) that have been published by PJM as part of the 2022–2023 BRA planning parameters. For the 2022–2023 capacity auction, the reliability requirement (the load forecast plus a reserve margin) is falling from 26,112 MW to 23,931 MW while the capacity import capability into the COMED zone is increasing from 5,574 MW to 6,839 MW. Finally, we incorporated expected changes in supply resources, including the Jackson (1,116 MW) and Three Rivers (1,214 MW) natural gas combined cycle plants expected to come online in 2022 and 2023. We also incorporated approximately 1,200 MW of wind expected to come online in 2022 based on a review of the PJM queue and the U.S. Energy Information Administration's (EIA) planned generation database.[65]

When modeling future years, we assumed that all Exelon nuclear power plants in the PJM COMED zone bid at low prices with the intention to clear the market. This strategy would ensure that each plant receives full capacity revenues for its entire firm capacity.

[64] PJM Interconnect. November 9, 2020. "PJM Reestablishes Capacity Auction Schedule. PJM Inside Lines," available at https://insidelines.pjm.com/pjm-reestablishes-capacity-auction-schedule/.

[65] Due to limitations associated with modeling PJM delivery years (which go from June 1–May 31) instead of calendar years, the Jackson and Three Rivers plants each clear the capacity market one year later in the model than is anticipated. Jackson clears in the 2023–2024 delivery year and Three Rivers clears in the 2024–2025 delivery year in EnCompass.

Minimum Offer Price Rule implication

The FERC's December 19, 2019 MOPR order directs PJM to make significant changes to the way it operates its capacity market. Specifically, FERC directed PJM to expand the application of MOPR to all "state-subsidized" resources. Although all existing renewable energy resources are exempt, the order applies to all new renewable energy projects seeking to participate in PJM's capacity market that do not yet have an interconnection construction service agreement with PJM. The order also applies to all existing nuclear units.

State support for nuclear units through ZECs would fall under the definition of a state subsidy and thus subject a nuclear plant that receives ZEC payments to a price floor. The minimum offer price floors are established by PJM. In the case of existing nuclear plants, the minimum offer price floor is set based on the net avoidable cost rate (ACR). The ACR reflects a resource's annual costs. These are the costs that existing resources could otherwise avoid should they choose to retire. Net ACR is defined as a resource's ACR netted against the expected revenue from PJM's energy and ancillary services markets.

Historically, net ACR values for nuclear units would be well below any expected capacity market clearing price. For example, after FERC's MOPR order, the IMM produced preliminary estimates of net ACR values for different resource types.

Figure 20. Net ACR values for nuclear plants

		Net ACR
w/major maintenance	single unit	$378/MW-day
	multi-unit	$70/MW-day
w/o major maintenance	single unit	$180/MW-day
	multi-unit	$0/MW-day

Source: Monitoring Analytics. January 21, 2020. CONE and ACR Values – Preliminary, a report prepared by the Independent Market Monitor of PJM, available at https://www.monitoringanalytics.com/reports/Reports/2020/IMM_CONE_ACR_Preliminary_Report_20200121.pdf.

Figure 20 presents the IMM's estimates for nuclear units requiring major maintenance investments and those that do not. In addition, the net ACR values are calculated separately for single-unit nuclear plants versus multi-unit plants. Based on the IMM's estimates, there is little risk that a multi-unit nuclear plant subject to a price floor based on net ACR will fail to clear PJM's capacity auctions. This is because the net ACR estimates are well below historical capacity market clearing prices.

Figure 20. Net ACR values for nuclear plants

		Net ACR
w/major maintenance	single unit	$378/MW-day
	multi-unit	$70/MW-day
w/o major maintenance	single unit	$180/MW-day
	multi-unit	$0/MW-day

Source: Monitoring Analytics. January 21, 2020. CONE and ACR Values – Preliminary, a report prepared by the Independent Market Monitor of PJM, available at https://www.monitoringanalytics.com/reports/Reports/2020/IMM_CONE_ACR_Preliminary_Report_20200121.pdf.

If Byron and Dresden eventually receive ZEC payments, these plants would be subject to a net ACR price floor. We anticipate that the plants would still be able to bid into PJM's capacity market and clear the BRA, thereby receiving ongoing capacity market revenues.

Appendix D. EXELON'S EARNINGS OPTIMIZATION EFFORTS

Overview

In addition to evaluating Exelon's historical and current costs and revenues in order to forecast Exelon's likely nuclear fleet profitability, Synapse investigated the degree to which Exelon has explored opportunities to reduce costs and enhance revenues. Synapse posed questions related to Exelon efforts to modernize equipment and technology and to seek new markets to supplement power generation sales (e.g., waste heat.) Of the areas explored, four are worth describing: hydrogen generation, research and development into advanced fuel cladding coatings, increased flexibility using battery storage, and use of data analytics to optimize operations.

Opportunities reviewed

Hydrogen generation

<u>Nature of the opportunity</u>

Exelon has announced that it has been working with the U.S. Department of Energy and its national labs, academics at the Massachusetts Institute of Technology Energy Initiative (MITEI), and the Nuclear Regulatory Commission to develop innovative ways to repurpose its nuclear fleet to raise additional revenue.[66] Because nuclear units operate around the clock at nearly full power,[67] excess energy is available when customers use less electricity. During off-peak hours, the price of wholesale electricity from nuclear power can fall below $0.02 per kWh.[68] This presents a cost-effective opportunity to use this low-cost electricity to run polymer electrolyte membrane (PEM) electrolyzers to generate hydrogen.[69] Exelon could use the hydrogen produced to self-supply the nuclear plant's hydrogen need,

---

66 *MITEI and Exelon collaborate on clean energy research through MITEIs Low-Carbon Energy Centers* (Exelon News Release, February 16, 2016) https://www.exeloncorp.com/newsroom/mit-partnership; *Nuclear looks to hydrogen to pay the bills* (Reuters Events, August 18, 2020) https://www.reutersevents.com/nuclear/nuclear-looks-hydrogen-pay-bills; *Exelon Corporation Sustainability Report 2019,* p. 56. https://www.exeloncorp.com/sustainability/Documents/dwnld_Exelon_CSR%20(1).pdf; *Exelon actions and analysis of Hydrogen value propositions* (undated presentation) https://www.energy.gov/sites/prod/files/2018/08/f54/fcto-h2-scale-kickoff-2018-4-otgonbaatar.pdf.

67 The capacity factor for nuclear power plants is routinely over 90%. See U.S. Energy Information Administration, Table 6.07.B Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b.

68 *How the Midwest Can Lead the Hydrogen Economy: Matching Generation Assets to Distribution Markets in Planning Hydrogen Refueling Infrastructure for Trucking and Transit* (The Midwest Hydrogen Center of Excellence and the Maxine Goodman Levin College of Urban Affairs at Cleveland State University) p. 49. https://www.sartaonline.com/Content/uploads/Midwest-Hydrogen-Infrastructure-FINAL-986.pdf.

69 *Nuclear looks to hydrogen to pay the bills* (Reuters Events, August 18, 2020) https://www.reutersevents.com/nuclear/nuclear-looks-hydrogen-pay-bills.

reducing O&M costs and/or marketed the hydrogen offsite for clean peak power generation or to fuel a regional hydrogen economy.

Hydrogen can be used to store energy for grid resilience and as feedstock for the chemicals industry.[70] A robust regional hydrogen market for transportation could enable a hydrogen refueling infrastructure for long-haul trucking and buses between Pittsburgh and Minneapolis.[71] [redacted] [redacted] This integrated hydrogen production operation could be a potentially lucrative revenue stream to supplement revenue earned from power generation.[73]

"Similar to fossil plants, hydrogen is used to cool the generator as a coolant gas, and second—unique to nuclear plants—is that hydrogen is used to control the chemistry of the coolant water in both pressurized water and boiling water reactors."

– Dr. Uuganbayar Otgonbaatar, Exelon Corporate Strategy Manager

Patel, S. 2019. "Exelon Is Exploring Nuclear Power Plant Hydrogen Production." PowerMag.com, August 29. Available at www.powermag.com/exelon-is-exploring-nuclear-power-plant-hydrogen-production/.

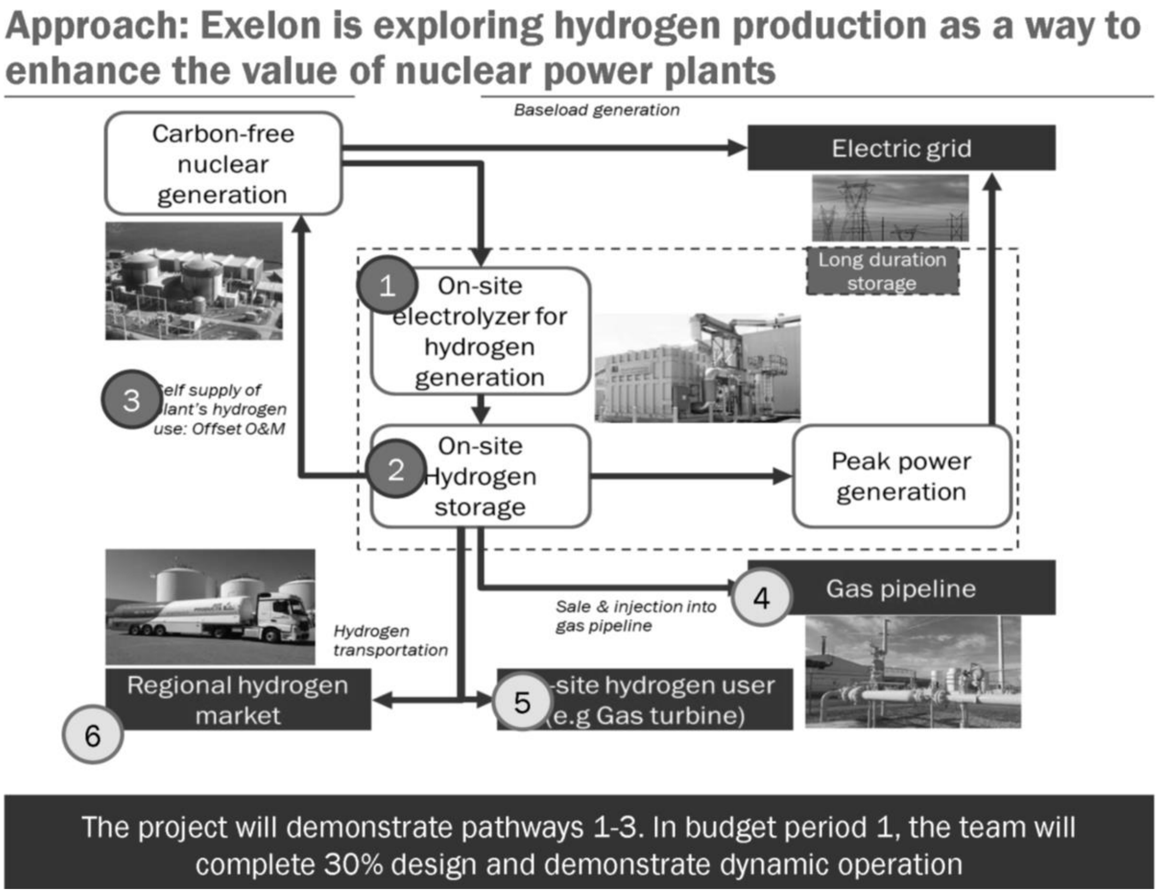
70 *Could Hydrogen Help Save Nuclear?* (DOE Office of Nuclear Energy, June 24, 2020) https://www.energy.gov/ne/articles/could-hydrogen-help-save-nuclear.

71 *How the Midwest Can Lead the Hydrogen Economy: Matching Generation Assets to Distribution Markets in Planning Hydrogen Refueling Infrastructure for Trucking and Transit* (The Midwest Hydrogen Center of Excellence and the Maxine Goodman Levin College of Urban Affairs at Cleveland State University) Executive Summary https://www.sartaonline.com/Content/uploads/Midwest-Hydrogen-Infrastructure-FINAL-986.pdf.

72 See 39_EXC_Audit_Response.

73 *Exelon Corporation Sustainability Report 2019,* p. 39. https://www.exeloncorp.com/sustainability/Documents/dwnld_Exelon_CSR%20(1).pdf; Patel, Sonal, *Exelon is Exploring Nuclear Power Plant Hydrogen Production* (Power, August 29, 2019) https://www.powermag.com/exelon-is-exploring-nuclear-power-plant-hydrogen-production/.

Figure 21. Exelon graphic describing hydrogen opportunity



Source: Otgonbaatar, Uuganbayar, Ph.D. 2020. DOE Hydrogen and Fuel Cells Program Review Presentation: Demonstration of electrolyzer operation at a nuclear plant to allow for dynamic participation in an organized electricity market and in-house hydrogen supply (Exelon Presentation, June 16, 2020) https://www.hydrogen.energy.gov/pdfs/review20/ta028_otgonbaatar_2020_p.pdf.

Status of Exelon's efforts

The U.S. Department of Energy awarded Exelon a conditional commitment to co-fund a demonstration of a 1-MW hydrogen electrolyzer at a nuclear plant site.[74] [redacted]

[74] *Exelon Corporation CDP Climate Change Questionnaire 2020 Wednesday, August 23, 2020.* Response to Dedicated budget for low-carbon product R&D, p. 73 and Response to Other, please specify Emerging Technologies, p. 136 https://www.exeloncorp.com/sustainability/Documents/Exelon_Investor_CDP.pdf#search=hydrogen.

[75] 75_EXC_Audit Response and 86_EXC_Audit_Reponse.

Assessment and recommendation

The potential revenue from this effort could be material in the future. Additionally, Exelon's pursuit of hydrogen production could be an economic driver for Illinois. We recommend the State consider linking the award of any subsidy to Exelon with support for a regional hydrogen economy in Illinois.

Advanced fuel cladding coatings R&D

Nature of the opportunity

A breach in the covering or "cladding" of the fuel pellets in a nuclear power plant is a "fuel failure." A common cause of fuel failure in boiling water reactors, such as those in Exelon's fleet, is mechanical "fretting." This is the wear that occurs on the fuel pellet surface when debris becomes trapped and vibrates against the fuel rod surface.[76] Fretting failures have long been a recognized as a frequent cause of operational problems harmful to nuclear plant economics.[77] A "boiling crisis" is a dangerous and potentially catastrophic physical condition that occurs when a steam layer forms over the boiling water impeding heat transfer.[78] To avoid a boiling crisis, nuclear plants operate at lower, less efficient temperatures. If the boiling crisis response could be averted or mitigated, nuclear plants could run at higher temperatures and generate more energy with the same fuel.[79] Exelon is pursuing, in collaboration with the MIT Center for Advanced Nuclear Energy Systems, research into engineered cladding surface coatings and micro/nano geometric modifications to reduce or eliminate fretting, the buildup of porous corrosion deposits, hydrogen absorption, and boiling crises.[80] If Exelon is successful, it will be able to both reduce operating expenses due to fretting and enhance revenue from its own fleet by increasing operating temperatures. It could also enjoy enhanced revenues from patenting and selling the solution to other operators of both boiled and pressurized water reactors.

Status of Exelon's efforts

[redacted]

[76] *Frequently Asked Questions: Fuel Reliability Guidelines* (Electric Power Research Institute, undated) http://mydocs.epri.com/docs/public/FRP%20DEL%20FAQ1c.pdf.

[77] *Fuel failure in water reactors: Causes and mitigation: Proceedings of a Technical Meeting held in Bratislava, Slovakia, 17-21 June 2002* (IAEA-TECODC-1345) https://www-pub.iaea.org/MTCD/Publications/PDF/te_1345_web/t1345_part1.pdf.

[78] *Getting to the bottom of the "boiling crisis" New understanding of heat transfer in boiling water could lead to efficiency improvements in power plants* (MIT News, April 4, 2019) https://news.mit.edu/2019/boiling-crisis-nuclear-design-0405.

[79] *Ibid.*

[80] *Exelon Generation supports research on advanced nuclear fuel cladding coatings* (MIT New Release, April 19, 2017) https://news.mit.edu/2017/exelon-generation-provides-funding-research-advanced-nuclear-fuel-cladding-coatings-0419.

[81] 80_EXC_Audit_ Response.

Assessment and recommendation

The potential revenue from this effort could be material in the future. Exelon's development of innovative coatings could improve the economics of its own nuclear fleet. But more substantially, Exelon could also patent and market its solution across the nuclear industry for other boiled water reactors. We recommend the State consider incorporating an adjustment to any subsidy awarded to account for this potential revenue stream.

Battery storage pairing

Nature of the opportunity

The electricity grid is fast undergoing a transition from a steady state to a more flexible system. This new system will be capable of integrating increasing amounts of variable renewable energy and increased loads from electric vehicles and electrification of heating. Nuclear power plants in the United States have limited experience operating flexibly.[82] Energy storage technologies can mitigate challenges faced by nuclear generation resulting from the increased need for grid flexibility.[83] Lithium-ion batteries are well suited to grid-scale systems to provide frequency regulation, reserves, and other grid stabilization services.[84]

Status of Exelon's efforts

[redacted]

Assessment and recommendation

Given the swiftly changing economics of battery storage costs, Exelon's analysis is stale and could benefit from an update with current battery storage costs.

---

[82] Coleman, Justin, Shannon Bragg-Sitton, Ph.D., Eric Dufek, Ph.D., Sam Johnson, Joshua Rhodes, Ph.D., Todd Davidson, Ph.D., Michael E. Webber, Ph.D. *As Evaluation of Energy Storage Options for Nuclear* Power (Idaho National Laboratory, June 2017) Introduction, p. vi https://www.osti.gov/servlets/purl/1372488.

[83] Coleman, Justin, Shannon Bragg-Sitton, Ph.D., Eric Dufek, Ph.D., Sam Johnson, Joshua Rhodes, Ph.D., Todd Davidson, Ph.D., Michael E. Webber, Ph.D. *As Evaluation of Energy Storage Options for Nuclear* Power (Idaho National Laboratory, June 2017) Introduction, p. vi https://www.osti.gov/servlets/purl/1372488.

[84] Coleman, Justin, Shannon Bragg-Sitton, Ph.D., Eric Dufek, Ph.D., Sam Johnson, Joshua Rhodes, Ph.D., Todd Davidson, Ph.D., Michael E. Webber, Ph.D. *As Evaluation of Energy Storage Options for Nuclear* Power (Idaho National Laboratory, June 2017) p. 48 https://www.osti.gov/servlets/purl/1372488.

[85] 39_EXC_Audit_Response and 83_EXC_Audit_Response.

Data validation and reconciliation models

Nature of the opportunity

Nuclear plant operators can use data analytics to improve O&M.[86] While other sectors have been using data analytics to crunch data into actionable and profitable information, utilities have not been particularly early adopters. However, information collected by the nuclear industry trade association, the Nuclear Energy Institute, demonstrates that nuclear plant operators have recently been able to arrest the precipitously rising costs of nuclear power generation and roll them back to below 2002 costs.[87] To some degree, NEI's documented reduction in operations costs may be likely due to the adoption of data analytics. Exelon began pooling data in 2015 and mining it with the aim of reducing operational costs and plant downtime.[88] Since then, Exelon has begun using new digital innovations to improve its nuclear operations.[89]

Table 6. Nuclear Energy Institute US nuclear plant costs ($/MWh in 2019 dollars)

Year	Fuel	Capital	Operations	Total Generating
2002	$6.18	$4.23	$20.08	$30.50
2004	$5.70	$6.10	$20.02	$31.82
2007	$5.54	$6.61	$20.59	$32.73
2010	$7.29	$10.09	$22.46	$39.83
2011	$7.64	$11.02	$23.81	$42.47
2012	$7.97	$12.19	$24.41	$44.57
2015	$7.37	$8.60	$22.49	$38.45
2016	$7.16	$7.18	$21.76	$36.11
2017	$6.71	$6.92	$21.39	$35.03
2018	$6.47	$6.32	$20.12	$32.91
2019	$6.15	$5.71	$18.55	$30.41
2018-2019 Change	-4.90%	-9.60%	-7.80%	-7.60%
2012-2019 Change	-22.70%	-53.10%	-24.00%	-31.80%

Source: Nuclear Energy Institute, Nuclear Costs in Context.

86 *Using Data Analytics to Improve Operations and Maintenance* (Power Magazine, March 1, 2018) https://www.powermag.com/using-data-analytics-to-improve-operations-and-maintenance/.

87 *Nuclear Costs in Context* (Nuclear Energy Institute, October 2020) p. 3. https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/Nuclear-Costs-in-Context.pdf.

88 *Power Up: GE Software Helps Exelon Make the Most Of Its Data* (GE News Release, October 26, 2017) https://www.ge.com/news/reports/power-ge-software-helps-exelon-make-data.

89 *Nuclear Power Upgrades* (Harvard Technology and Operations Management MBA Student Perspectives, November 20, 2016) https://digital.hbs.edu/platform-rctom/submission/nuclear-power-upgrades/.

<u>Status of Exelon's efforts</u>

[redacted]

<u>Assessment and recommendation</u>

No further action recommended.

Conclusions

It is premature to forecast additional reduced costs and/or enhanced revenues due to the Exelon optimization efforts reviewed by Synapse. However, Synapse recommends that Illinois:

- Consider linking the award of any subsidy to Exelon with support for a regional hydrogen economy in Illinois;
- Given the swiftly changing economics of battery storage costs, consider encouraging Exelon to update its analysis of battery-nuclear pairing with current battery storage costs; and
- Consider incorporating an adjustment to any subsidy awarded to account for a potential revenue stream from the licensing and/or sale of patented coatings.

[90] 87_EXC_Audit_Response.

[91] 76_EXC_Audit_Response.

Appendix E. ENCOMPASS INPUTS

Synapse used EnCompass to model the energy and capacity prices across MISO and PJM. Developed by Anchor Power Solutions, EnCompass is a single, fully integrated power system platform that provides an enterprise solution for utility-scale generation planning and operations analysis.[92] EnCompass is an optimization model that covers all facets of power system planning, including:

- Short-term scheduling, including detailed unit commitment and economic dispatch, with modeling of load-shaping and shifting capabilities;
- Mid-term energy budgeting analysis, including maintenance scheduling and risk analysis;
- Long-term integrated resource planning, including capital project optimization, economic generating unit retirements, and environmental compliance; and
- Market price forecasting for energy, ancillary services, capacity, and environmental programs.

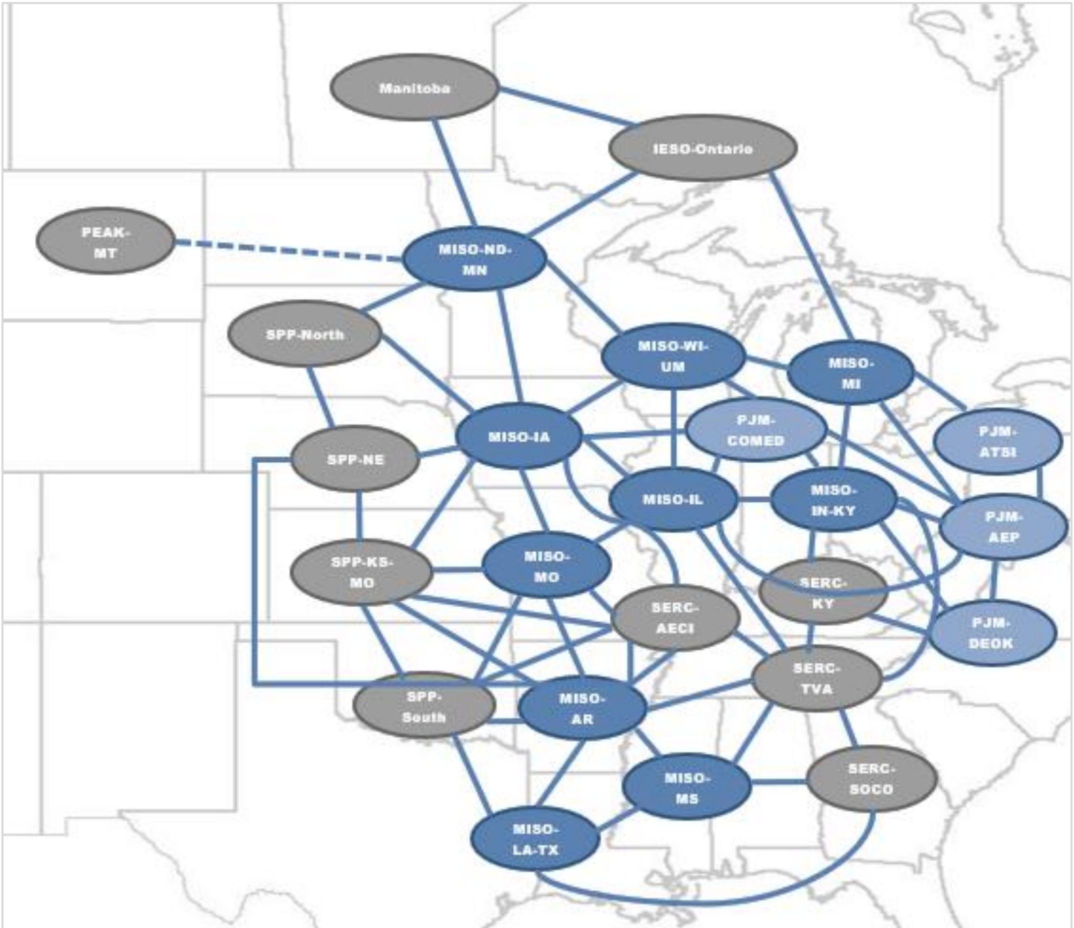
Synapse populated the MISO and PJM model using the EnCompass National Database created by Horizons Energy. Horizons Energy has benchmarked dispatch and prices resulting from its comprehensive dataset to actual, historical data across all modeling zones. More information on EnCompass and the Horizons dataset is available at www.anchor-power.com.

Topology and transmission

Synapse modeled the entire PJM and MISO region with full unit-level operational granularity at a zonal level. Additionally, we modeled external contract regions representing Manitoba, IESO-Ontario, NYISO, MISO, SERC, and SPP regions. We relied on transmission assumptions from the EnCompass National Database. The zones highlighted in light and dark blue in the Figure 22 and Figure 23 represent the areas modeled at a full unit granularity. The zones highlighted in grey are the areas modeled as contract regions.

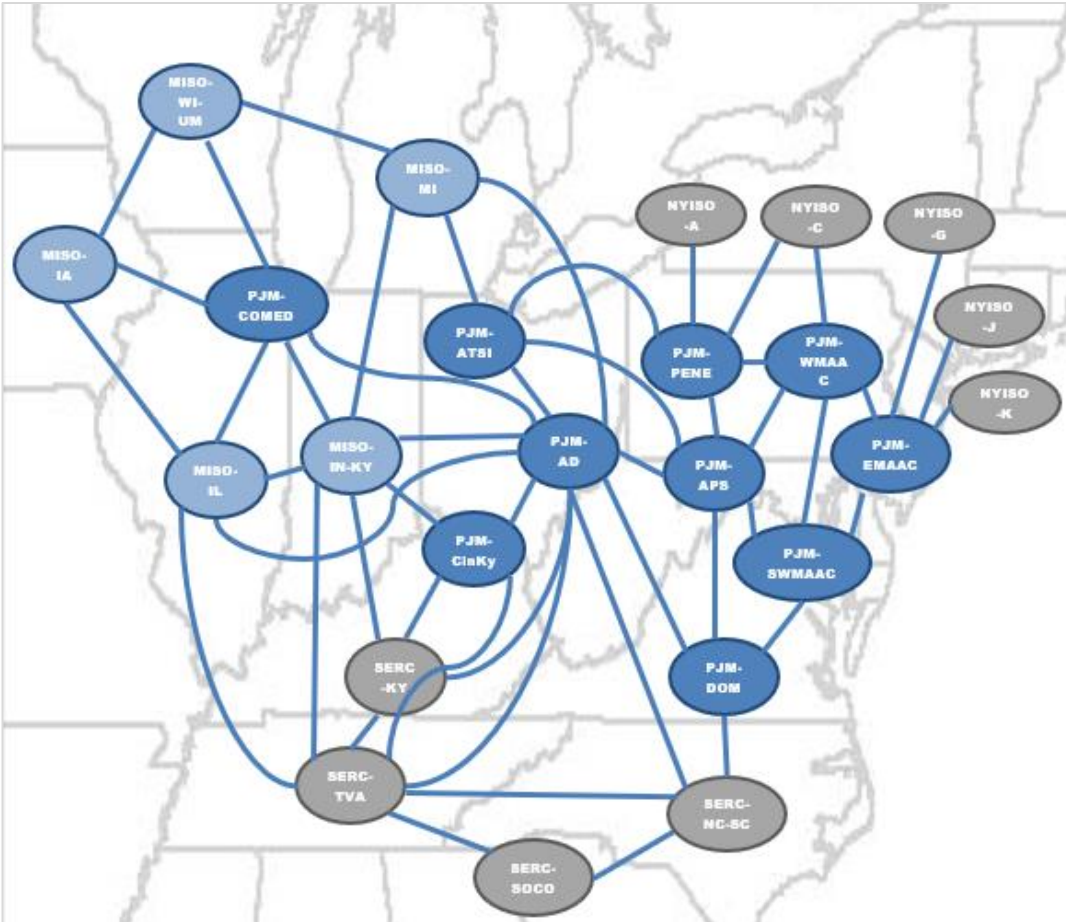
[92] More information regarding the EnCompass model may be found at: https://anchor-power.com/.

Figure 22. MISO modeling topology



Source: EnCompass National Database.

Figure 23. PJM modeling topology



Source: EnCompass National Database.

Peak load and annual energy

Synapse relied on annual energy and peak load as defined in the NERC Long-term Reliability Assessment, the MISO Energy and Peak Demand Forecasting for System Planning conducted by the State Utility Forecasting Group (SUFG), and the PJM Load Forecast Reports.[93]

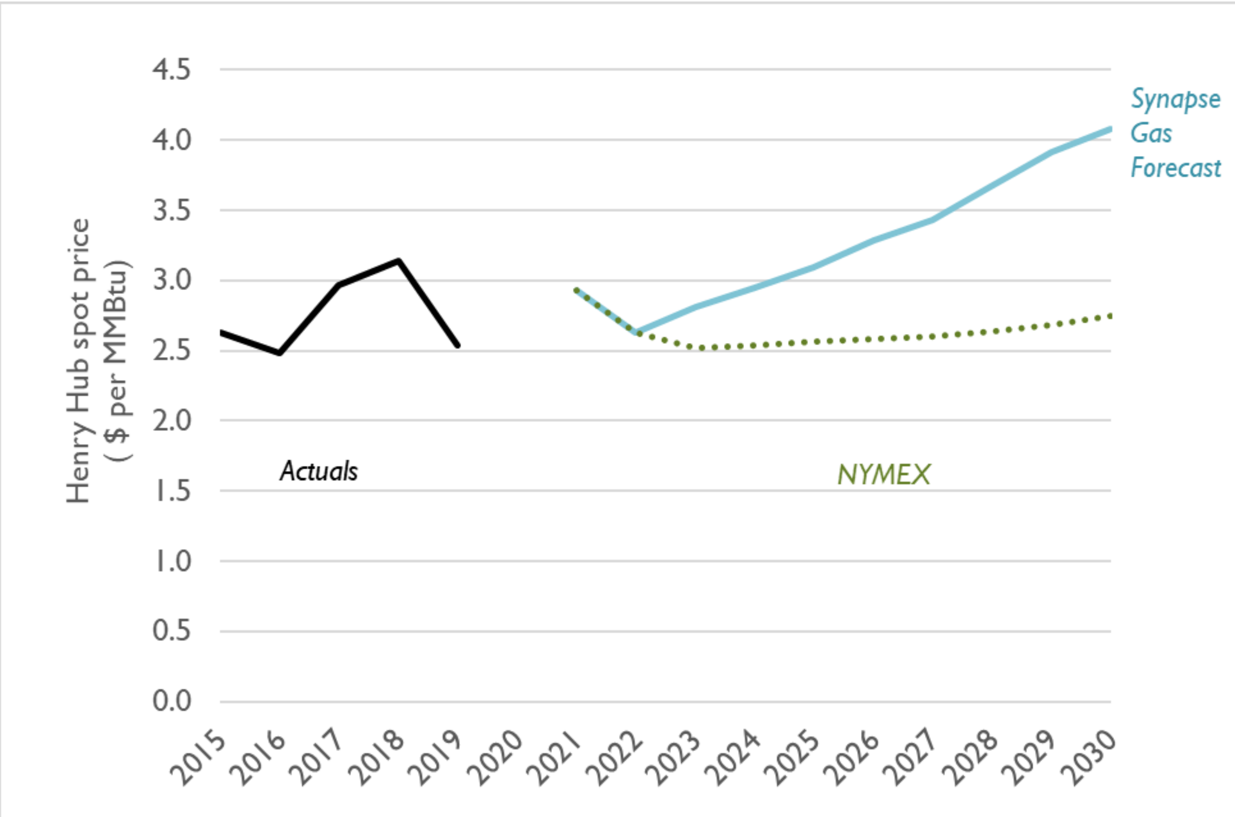
Fuel prices

For the natural gas price forecast, Synapse relied on NYMEX futures for monthly Henry Hub gas prices through 2022. For 2023, Synapse used a blend of NYMEX futures and the prices projected for Henry Hub

[93] NERC Electricity Supply and Demand, January 2021: https://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx; 2019 MISO Energy and Peak Demand Forecasting for System Planning, https://cdn.misoenergy.org/2019%20MISO%20Energy%20and%20Peak%20Demand%20Forecasting%20for%20System%20Planning420836.pdf; PJM Load Forecast Report, January 2021: https://www.pjm.com/-/media/library/reports-notices/load-forecast/2021-load-report.ashx.

in the AEO 2021 Reference Case (published February 2021).[94] For all years after 2023, Synapse used the Henry Hub AEO 2021 Reference Case price projections. Figure 24 below shows the trajectory of the Synapse natural gas price forecast relative to NYMEX futures as of March 29, 2021. We then applied trends in average monthly prices observed in the 2022–2023 NYMEX futures to this longer-term gas price to develop long-term monthly trends that reflect gas price seasonality. Henry Hub gas prices provides the basis for all the gas prices. For each of the zones, delivery price adders that reflect the price differential at the regional supply points are sourced from the EnCompass National Database.

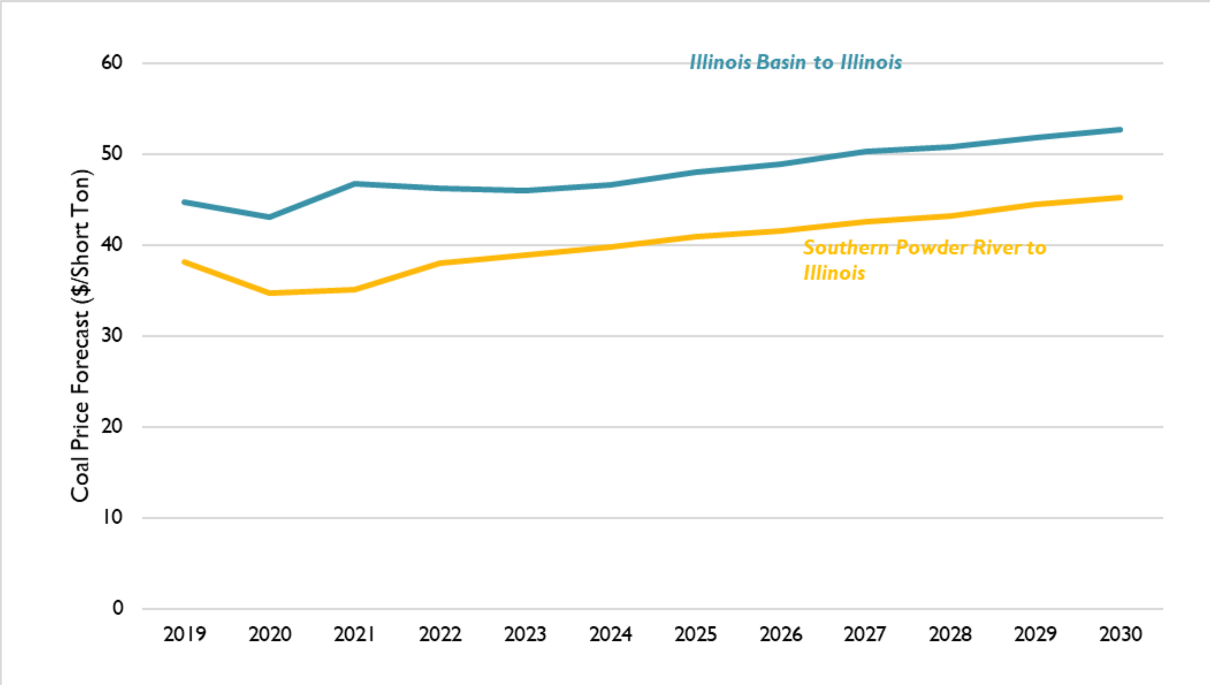
Figure 24. Synapse natural gas price forecast compared to NYMEX futures as March 29, 2021



For coal prices, Synapse relied on the EnCompass National Database for unit-level coal price forecasts. For the PJM region, the database relies on 21 discrete forecasts and projects costs for coal sourced from the Northern Appalachia, Central Appalachia, Southern Powder River, International, and Illinois Basin regions. Figure 25 shows the coal price forecasts from Southern Powder River Basin and Illinois Basin to the modeled territories. These coal price costs reflect the commodity- and transportation-related costs to Illinois from the respective basins.

[94] EIA. Annual Energy Outlook 2021. February 3, 2021. Available at https://www.eia.gov/outlooks/aeo/.

Figure 25. Coal price forecast



Resource costs

Solar and storage capital costs in our model are based on the moderate scenario for National Renewable Energy Laboratory *Annual Technology Baseline* (NREL ATB) inclusive of locational adjustments based on EIA's *Capital Costs* report. [95] Thermal unit parameters are based on EIA data. Wind capital costs are sourced from the EnCompass National Database.

Renewable energy programs

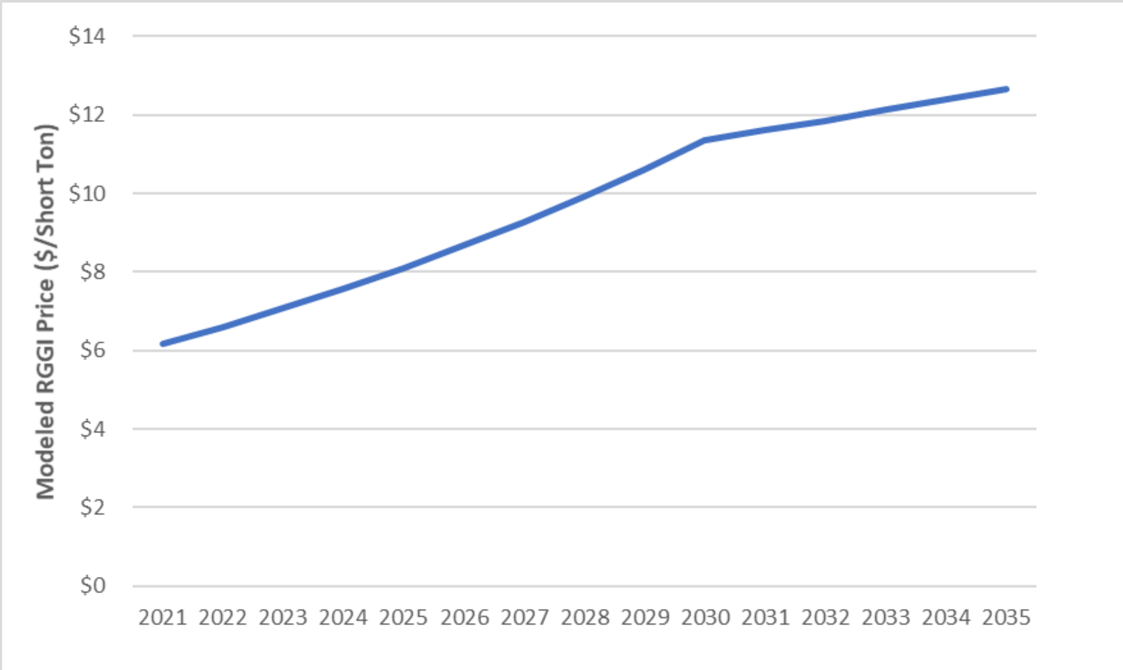
Synapse modeled the REC allowance programs within MISO and PJM incorporating individual state's renewable portfolio standards. Within MISO and PJM, Synapse also modeled any solar and wind carve-outs for each respective state based on the renewable portfolio standards. Where applicable, Synapse also modeled RGGI prices for the participating RGGI states. [96]

---

[95] NREL ATB: https://atb.nrel.gov/electricity/2020/data.php; *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, February 2020: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.

[96] The RGGI price forecast is sourced from the EnCompass National Database. The forecast closely tracks the Emissions Containment Reserve (ECR) trigger price: https://www.rggi.org/sites/default/files/Uploads/Program-Review/12-19-2017/Principles_Accompanying_Model_Rule.pdf.

Figure 26. RGGI carbon price ($/short ton) (nominal dollars)



Source: EnCompass National Database

Appendix F. MONTE CARLO ANALYSIS INPUTS

This appendix provides a detailed description of the methods and data used in the Monte Carlo analysis that we used to assess market and operational risk. As discussed in Section 2.1, the Monte Carlo model is designed with NPV as the objective function. Before calculating the NPVs during each simulation of the Monte Carlo, the model first estimates a series of parameters which determine net cashflows for each plant. This section will discuss in greater detail how the model applies uncertainty and random variation during the calculations of these intermediate parameters. We also provide the data sources we used to generate the uncertainty distributions.

Revenues

Plant revenues are derived from several sources, with the two greatest contributors being energy and capacity revenues. Both of these sources are subject to random variation in the Monte Carlo. In addition, the model includes ancillary service revenue, which is not subject to random variation in Synapse's model.

Energy revenues

Energy revenues were modeled on a monthly basis to capture the potential for seasonal fluctuations in price. For each month, the model starts with the EnCompass energy price as an input. Next the Monte Carlo performed a random draw from the distribution of forward price variation ratios. [redacted]. Each random draw produced a variation ratio, which represents a percentage by which the expected value will subsequently be scaled. For instance, if the random draw produces a variation ratio of 120 percent then the observed energy price will be 20 percent greater than the expected value for that month. Once the observed energy price was estimated, the model calculated zonal energy revenue as the product of observed energy prices and projected monthly generation. Lastly, the model converted zonal energy revenue to plant energy revenue by applying a bus differential adjustment to zonal energy revenue. The adjustment was calculated as the product of monthly generation and an annual per MWh bus-differential between zonal and bus energy prices.

Our Monte Carlo model incorporated two types of energy prices: (1) forward-market energy prices, which represent the prices earned by Exelon for all energy it sells, and (2) spot-market energy prices, which represent the prices incurred by Exelon for all replacement energy that it must purchase during periods of forced outage. We modeled the forward- and spot-market energy prices in our Monte Carlo analysis using results from Synapse's production cost and capacity expansion model of the PJM and MISO markets (described in Section 2.2).

The forward energy price distribution is a distribution of ratios. Each ratio determines the amount of variation which will be applied to the expected value energy price to estimate the observed energy price. A ratio of 100 percent would result in an observed price equal to the expected price. The variation ratios for the forward price distribution were calculated by taking the monthly average of hourly day-ahead PJM–COMED energy prices and dividing by the forward-looking three-month rolling average. For example, the variation ratio for January of 2015 would divide the average energy price in January 2015 by the three-month rolling average energy price from January 2015 to March 2015. The historical PJM–COMED day-ahead energy price data is reported in hourly intervals and spans the time period beginning January 1, 2011 and ending December 31, 2020. The analysis calculated 118 monthly variation ratios over that period.[97] Next, the analysis created a distribution by calculating percentiles (ranging from 0.1 to 100.0 at increments of 0.1) from the dataset of monthly variation ratios. This distribution is then fed into the Monte Carlo forward energy price module, where the model used it as a source for randomly drawn variation ratios.

Exelon employs a range of strategies to hedge against risk and reduce exposure to volatility in energy market prices. [redacted]

The spot price distribution differs for each month, so there were actually 12 distinct distributions used in the model. Each of these 12 distributions was constructed in the same way and was identical in structure, providing a set of 100 variation ratios which determine the amount of variation between the expected value spot price and the observed spot price. The first step in constructing the spot price distributions was to use the PJM–COMED day-ahead energy price data to estimate variation ratios for each hour. Each ratio was calculated by dividing the PJM–COMED day-ahead energy price in a given hour by the average day-ahead energy price within the month in which that hour occurs. For example, the variation ratio for Hour 12 on January 1, 2015 would be calculated by dividing the reported day-ahead price during that hour by the average day-ahead price during January 2015. The result was a set of 87,488 observed variation ratios. The final step in creating the monthly spot price distributions was to calculate the percentiles from the observed hourly variation ratios. During this step, observations and percentiles were grouped by month, meaning that the nth percentile for January was estimated using

[97] The analysis did not calculate variation ratios for November or December of 2020 as there are not enough months of data to calculate a forward-looking three-month rolling average for these months.

only observations which occurred during the month of January between 2011 and 2020. The resulting datasets were input into the Monte Carlo model and used as sources of random variation in the spot price module.

Capacity revenues

Capacity revenues, unlike energy revenues, are determined on an annual basis. The model began with an expected capacity revenues for each plant based on the forecasted capacity price from the EnCompass model. For each year, the model then performed a random draw from a distribution of possible observed capacity prices, which is normally distributed around the EnCompass capacity price, to determine the variation in capacity revenues. The applied a normal distribution based on the expected value capacity revenue as well as a plant-specific capacity revenue standard deviation. The standard deviation was constant for each plant, with the exception of Dresden, which is projected to have Unit 2 retire in 2029 and thus required a different standard deviation in that year. The result of the random draw became the observed capacity revenue in each year, which flowed directly into our estimate for total revenues.

Our Monte Carlo model incorporated capacity price results from Synapse's production cost and capacity expansion model of the PJM and MISO markets (described in section 2.2). To account for year-to-year uncertainty in capacity prices, Synapse evaluated the changes in available capacity in PJM between consecutive years. We reviewed data from EIA that showed added and retired capacity for each year between 2002 and 2020. Based on the limited sample size available, we determined that the distribution of annual change in nameplate capacity was approximately normal. The net change in total nameplate capacity over that time period varied between a decline of 6,752 MW and an increase of 11,569 MW of generation. From this range, we determined that over 20 years the expected range of annual nameplate capacity changes is approximately 20,000 MW.

We then estimated the impact on pricing of both an increase and a decrease of 10,000 MW, using PJM's published approximate supply curve for the most recent BRA. Our simplified supply and demand model showed that the price difference between a 10,000 MW increase in available capacity and a 10,000 MW decrease in available capacity in the most recent BRA would have been approximately $40/MW-day. This range was the result of a sample of just under 20 observations (the years 2002 to 2020), and in a normal distribution, 1 in 20 observations would be expected to fall outside of a two-standard-deviation range. Therefore, we determined that the $40/MW-day price range was equal to four standard deviations for the distribution (from two standard deviations below the mean to two standard deviations above the mean). As a result, we calculated that the standard deviation in year-to-year capacity price fluctuations would be expected to be about $10/MW-day.

Ancillary service revenue

After energy and capacity revenues have been estimated, total revenue can be calculated as the sum of energy revenue, capacity revenue, and ancillary revenue. The latter parameter does not vary from its expected value, for which Exelon's forecasts were used.

Expenses

Exelon's expenses at each plant are a combination of five cost categories: O&M, overhead, outage costs, capital expenditures, and spent fuel costs. For all the expense parameters the expected values [redacted].[98] The Monte Carlo analysis modeled random variation for each of the cost categories independently before combining them to provide an estimate of annual expenses.

O&M costs

O&M costs include two sub-categories of costs: [redacted]) and [redacted]. Each of these were estimated annually by taking an independent random draw from a distribution of variation ratios and multiplying the result by the expected value cost. Next, the model added the [redacted] to produce an estimate of total O&M costs for each year.

We used Exelon's forecast of O&M expenses in our predictive model and incorporated uncertainty based on historical variation in the expense categories. Synapse developed separate distributions to characterize the possible variation in both of Exelon's O&M categories. First, we reviewed 10 years of historical cost data provided by Exelon through discovery and calculated average annual costs for each expense account on a plant-by-plant basis. Next, we developed a series of scalar values equal to the ratio of a plant's annual expenses within a specific expense account divided by the historical average value for that plant. Using these results, we assembled a combined probability distribution across all plants of year-to-year variation in cost data relative to average. This approach assumed that future plant-specific costs can vary as much as any other plant costs within Exelon's Illinois fleet in the last 10 years.

Overhead costs

Overhead costs can be broken down into five sub-categories of cost: property tax, direct BSC, nuclear corporate overhead—direct charge to site, nuclear corporate overhead—Institute of Nuclear Power Operations (INPO) allocated to site, and non-nuclear overhead. Each of these costs were estimated using the same methodology as the O&M costs, with independent random draws from a distribution of sub-category-specific variation ratios occurring annually. Once the model completed the random draws, it multiplied expected values by the randomly selected variation ratios to produce an estimate of observed costs for each sub-category. Lastly, the model summed the sub-category costs to estimate total overhead costs for each year.

As with O&M expenses, [redacted] and incorporated uncertainty based on historical variation. We developed five distributions of possible variation, one for each of Exelon's overhead cost categories. Using the same approach as with O&M costs, we (1) calculated 10-

98 EXC Audit 84.

year average annual costs on a plant-by-plant basis; (2) developed scalar ratios (a plant's annual expenses within an expense account divided by the historical average value for that plant); and (3) assembled a combined probability distribution across all plants of year-to-year variation in cost data relative to average.

Outage costs

Outage costs can occur in two ways. Scheduled outages are planned for in advance and are used to allow for refueling of the reactors. These outages are planned for and have expected costs. Scheduled outage costs can vary, particularly when the duration of an outage differs from the forecast duration. All else equal, shorter durations than planned result in cost reductions while longer durations result in cost over-runs. Unscheduled outages are unplanned, and therefore are not included directly in Exelon's expense forecast (*i.e.*, have an expected cost of zero). For example, these occur when Exelon must unexpectedly halt generation at a plant, such as when it must repair failing equipment. Unscheduled outages increase costs; if an unscheduled outage is required the costs will be positive, but if no unscheduled outage occurs costs will remain at zero.

Each outage, regardless of type, impacts Exelon's costs in two ways. First, direct cost impacts occur when Exelon incurs (or avoids) incremental costs associated with the outage itself (*e.g.*, per-day costs associated with labor, contracting, materials, etc.). Secondly, indirect cost impacts occur when Exelon must address changes in expected generation caused by variation in outage length. If outages run longer than expected, Exelon must purchase power from the spot market to deliver energy for which it is contracted, but is no longer able, to deliver. If an outage runs shorter than expected (which is only possible for scheduled outages) Exelon can sell excess generation on the spot market, which the Monte Carlo treated as a reduction of outage costs.

The first step in modeling outage costs was to estimate outage duration impacts for each month. This was accomplished by taking a random draw for each month in a year from a distribution of outage duration variation. The random draw was used in every month to model random variation in unscheduled outage duration, but it was only applied during months with planned outages when modeling scheduled outage duration. The distribution of duration impacts included both negative values and positive values for scheduled outages, while for unscheduled outages it had a minimum of zero. A random draw from these distributions can be understood as the incremental number of days an outage will last relative to the expected value outage duration. For instance, if the random draw produces a negative five for the scheduled outage draw, then that implies that the scheduled outage was five days shorter than anticipated. Alternatively, a positive five would suggest that the outage was five days longer than anticipated.

We developed uncertainty distribution for the possible durations of scheduled and unscheduled outages. Unscheduled outages were modeled a monthly basis. We used historical unscheduled outage data for each of Exelon's 11 nuclear generating units to develop a month-by-month record of the possible quantity of per-unit outage days (including a value of zero for each month in which a plant did not have an unscheduled outage). We used this resulting dataset to assemble a probability distribution from 1,320 possible monthly outage durations: 11 units × 10 years × 12 months. This approach assumed that future plant-specific unscheduled outage durations can vary as much as any plant in Exelon's Illinois fleet has varied in the last 10 years. To create a distribution of possible changes to scheduled outage durations we assembled two intermediate probability distributions: one each for Exelon's historical and forecast scheduled outage durations. We assigned percentile scores to each outage duration in the two distributions and quantified the differential between equal-ranked outage durations. We used the series of outage duration differentials to assemble the final distribution of uncertainty in scheduled outage length.

The second step in modeling outage costs was to translate changes in outage duration into changes in outage cost. To estimate the direct cost input, the model conducted a random draw from a distribution of historical outage costs to determine the direct cost per-day of each outage. This result was then multiplied by the change in outage days. If the change in outage days is negative, implying an outage took less time than projected, the cost impact will manifest itself as a reduction in direct outage costs.

Synapse prepared distributions for the possible per-day costs of outages: O&M expenditures for scheduled outages, O&M expenditures for unscheduled outages, and capital expenditures for unscheduled outages. We used 10-year historical scheduled outage cost data from Exelon's six nuclear plants to develop per-outage daily costs. Similarly, we used a 10-year log of historical unscheduled outage costs, both O&M and capital, to develop a series of per-outage costs. Note that while all unscheduled outages incur O&M costs, Exelon only records O&M costs associated with unscheduled outages when Exelon believes that data will be useful for circumstances that could occur in the future. Therefore, the dataset we used is not comprehensive of all unscheduled O&M costs in the last 10 years and may be biased toward either higher or lower costs per day, depending on the comparative per-day costs that were tracked versus not tracked. As discussed above, scheduled outages can result in incremental capital expenses if unforeseen issues are discovered. To account for this potentiality, we included in the distribution of per-day costs [redacted] unplanned capital expenditures that occurred during scheduled outages, as identified by Exelon through discovery.

One feature of direct outage costs which differs for scheduled and unscheduled outages is how the costs are reported by Exelon. All scheduled direct costs are recorded as outage costs, but unscheduled direct outage costs are split between capital expenditures and O&M costs by using distinct distributions of per-day costs for the two respective categories. The reason for this feature is that capital expenditures which occur during scheduled outages are logged as such, with most of these expenses being recorded as fuel capital expenditures. Fuel capital costs will be relatively fixed and are not dependent on the length of a scheduled outage. As such, the variations in scheduled outage length affect only the incremental O&M costs of scheduled outages, which are logged as outage costs. However, it is possible that Exelon will incur incremental capital expenses during a scheduled outage if, for example, an equipment failure is discovered through inspections conducted during the outage and addressed at that time. Unscheduled outages are different in that the capital expenditures associated with them are not planned for, and so they are not reflected in Exelon's capital expenditures forecasts. As such, when an unscheduled outage does occur, Exelon is forced to incur the cost of incremental capital expenditures, the treatment of which are discussed further under capital expenditures. In addition, unscheduled outages cause incremental O&M costs which are treated in the same way as scheduled outage O&M costs.

The next step in modeling outages was to estimate indirect outage costs. We assumed that energy bought or sold due to changes in outage duration must be purchased on the spot market using day-ahead prices. To incorporate greater potential for variation into the spot market prices, the Monte Carlo analysis modeled spot prices differently from the forward energy prices used to calculate energy revenues. The model first started with monthly energy price expected values, which were output from the EnCompass model. These expected values were the same as those used for the forward energy price estimation. Next a random draw was conducted for each hour in a month from a distribution of spot price variation ratios. The model then calculated hourly prices as the product of the hourly price variation ratios and the expected value for the monthly price. Lastly, it averaged the hourly prices to estimate the observed average monthly spot price. This process was repeated for each month in each year of the study period. Indirect outage costs could then be calculated as the product of outage duration variation, the observed monthly average spot price, and generation per-unit per-day.

Capital Expenditures

Capital expenditures consist of two subcategories of cost: non-fuel capital expenditures and fuel capital expenditures. The model assumed that non-fuel capital expenditures are impacted only by unscheduled outage capital expenditures. This assumption holds that Exelon has properly planned all future capital expenditures in its forecast except for unexpected capital investments, which might be necessary during unscheduled outages. These unexpected capital expenditures were calculated as described in the outage cost section, but applied to capital expenditures when selected by the model. The impacts of unexpected capital spending cannot be less than zero, meaning that when non-fuel capital expenditures change, they can only increase relative to the expected value. Capital expenditures on fuel were assumed to be stable and did not vary about the expected value. Total capital expenditures are the sum of non-fuel and fuel capital expenditures.

Spent Fuel Costs

Exelon accounts for spent fuel costs each year by budgeting a spent fuel cost of $0.955/MWh each year. However, this fee has not been assessed by the Department of Energy since May of 2014 due to a lack of a suitable disposal programs, as discussed in more detail below. We modeled uncertainty in spent fuel costs by applying random variation to the application of this fee. Functionally, the Monte Carlo model accomplished this by taking a random draw from a distribution of binary outcomes which determine whether the fee is applied in each year of the study period. Once application of the fee began, the model assumed that it would continue to be applied for the remainder of the study period. The probability function of the DOE reviving the spent nuclear fee in the future grows at 3 percent per year starting at 0 percent for 2021. These initially low probabilities correspond with our understanding that DOE is unlikely to make a decision about long-term spent nuclear fuel storage in the near term.

Under the ZEC Act, "spent fuel expenses" are considered. Exelon has defined spent fuel expenses as the DOE spent nuclear fuel disposal fee and included it in its certified cost projections in its applications for the Clinton and Quad Cities plants. In Exelon's 2020 10-K, Exelon notes that it will not accrue any further costs related to spent nuclear fuel disposal fees until a new fee structure is in effect.[99]

We do not know the certainty, timing, or amount for a spent nuclear fuel disposal fee should DOE restart the collection. Currently, DOE has assets of $45.0 billion in the Nuclear Waste Fund.[100] DOE has not made any announcements to develop another spent nuclear fuel disposal site. We do not expect DOE will collect spent nuclear fuel disposal fees from nuclear plant owners in the next few years.

Spent nuclear fuel may also be stored onsite as part of a plant's decommissioning process that would be paid from existing decommissioning trust fund.[101] For the former Oyster Creek Nuclear Station, Exelon transferred the responsibilities of spent fuel storage to Holtec when Holtec took over the decommissioning trust fund and decommissioning responsibilities for the plant. The NRC granted Holtec a waiver to use the decommissioning trust fund for spent nuclear fuel storage.[102] For the Dresden Station, Exelon's most recent 10-K states:[103]

> Within two years after shutting down a plant, Generation must submit a [Post shutdown Decommissioning Activities Report] PSDAR to the NRC that includes the planned option for decommissioning the site. Upon retirement, Dresden will have adequate funding assurance; however, due to the earlier commencement of decommissioning activities and a shorter time period over which the [Nuclear Decommissioning Trust] NDT fund investments could appreciate in value, Byron may no longer meet the NRC minimum funding requirements and, as a result, the NRC may require additional financial assurance including possibly a parental guarantee from Exelon. Considering the different approaches to decommissioning available to Generation, the most likely estimates currently anticipated could require financial assurance for radiological decommissioning at Byron of up to $90 million.

We note that this shortfall pertains to the early retirement scenario for Byron in 2021.

Income tax

The final parameter which impacts net cashflow is the income tax. Exelon forecasts assume an income tax rate of 25.23 percent, which is applied to net income. The model used the same tax rate, holding it

---

[99] Exelon Corporation. Form 10-K Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the Fiscal Year Ended December 31, 2020. Page 341. Available at: https://investors.exeloncorp.com/static-files/ab8f2e58-fb68-4f1c-9197-bdca30371726.

[100] Department of Energy. Audit Report- Department of Energy Nuclear Waste Fund's Fiscal Year 2020 Financial Statement Audit. DOE-OIG-21-02. November 2020. Available at: https://www.oversight.gov/sites/default/files/oig-reports/DOE-OIG-21-02.pdf.

[101] The Nuclear Regulatory Commission uses the term Independent Spent Fuel Storage Installation (ISFSI) for the dry cask storage of spent nuclear fuel.

[102] Nuclear Regulatory Commission. Docket No. 50-219 Holtec Decommissioning International, LLC. Oyster Creek Nuclear Generating Station Exemptions. June 20, 2019. Available at: https://www.nrc.gov/docs/ML1917/ML19170A275.pdf.

[103] Exelon Corporation. 2020 10-K. Page 90.

constant throughout the study period. To calculate the value of the income tax, the model first estimated the net income. Functionally, this was done by removing the capital expenditures from costs and replacing them with capital depreciation and fuel amortization. For both depreciation and amortization, the model used Exelon's forecasts and did not apply random variation. Once net income was estimated, the income tax could be calculated as the product of the tax rate and net income.

Net cashflow

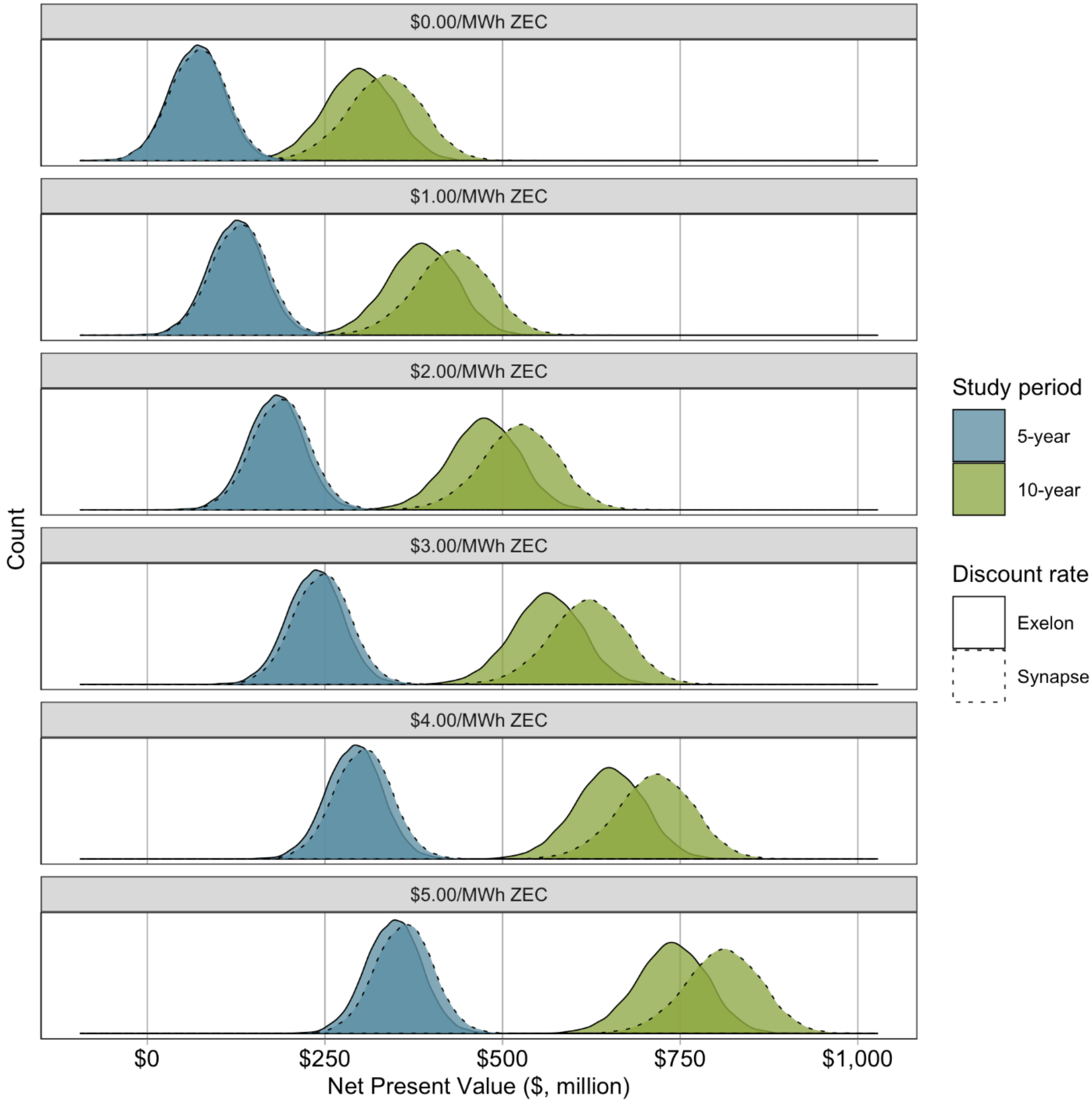
After the model had estimated all of the income and cost parameters, it calculated net cash flow as the difference between revenues and expenses in each year. A positive net cashflow is observed whenever revenues outweigh costs and a negative net cashflow is observed whenever the opposite is true.

Appendix G. Monte Carlo Analysis Results for Braidwood and LaSalle

Synapse evaluated Braidwood and LaSalle separately from Byron and Dresden because Exelon has planned for the imminent retirement of Byron and Dresden, but not Braidwood and LaSalle. Although we present the Braidwood and LaSalle results independently, we applied the same methods and data sources used to quantify the range of possible NPVs for the future operation of Braidwood and LaSalle. The results represent a span of potential future market and operational conditions inclusive of Exelon's expected future expenses, Synapse's forecast of plant revenues, and a range potential variation that is grounded in 10 years of operating experience and market data for Exelon's 11 Illinois nuclear units across six plant sites. We include scenarios (1) with ZEC values ranging from $0–$16.5/MWh, (2) with and without carbon pricing, (3) using 5-year and 10-year study periods, and (4) with the Synapse and Exelon discount rates. Figure 35 and Figure 28 present these NPV cash flows for Braidwood. Results for LaSalle are shown in Figure 37 and Figure 30. Compared to Exelon projections found in its discovery responses, our estimates of NPV are higher, primarily due to the differences in energy and capacity revenues.

Our Monte Carlo analysis indicated that the LaSalle and Braidwood plants would not require subsidies to ensure NPV cashflow during the period 2021–2025, as indicated by our results for scenarios without carbon pricing. For the no-ZEC subsidy simulations, the bottom 5th percentile of outcomes for Braidwood and LaSalle were all positive in the 5-year analysis at the Exelon discount rate. No subsidies were required to support either plant when we expanded the Monte Carlo study period to the timeframe 2021-2030, as all simulations for both plants resulted in positive NPV cash flows. Additionally, the scenario with carbon pricing resulted in positive NPVs under the 2021–2025 study period for LaSalle and Braidwood in all simulations.

Figure 27. Braidwood net present value cash flow, Baseline Scenario—Monte Carlo simulations



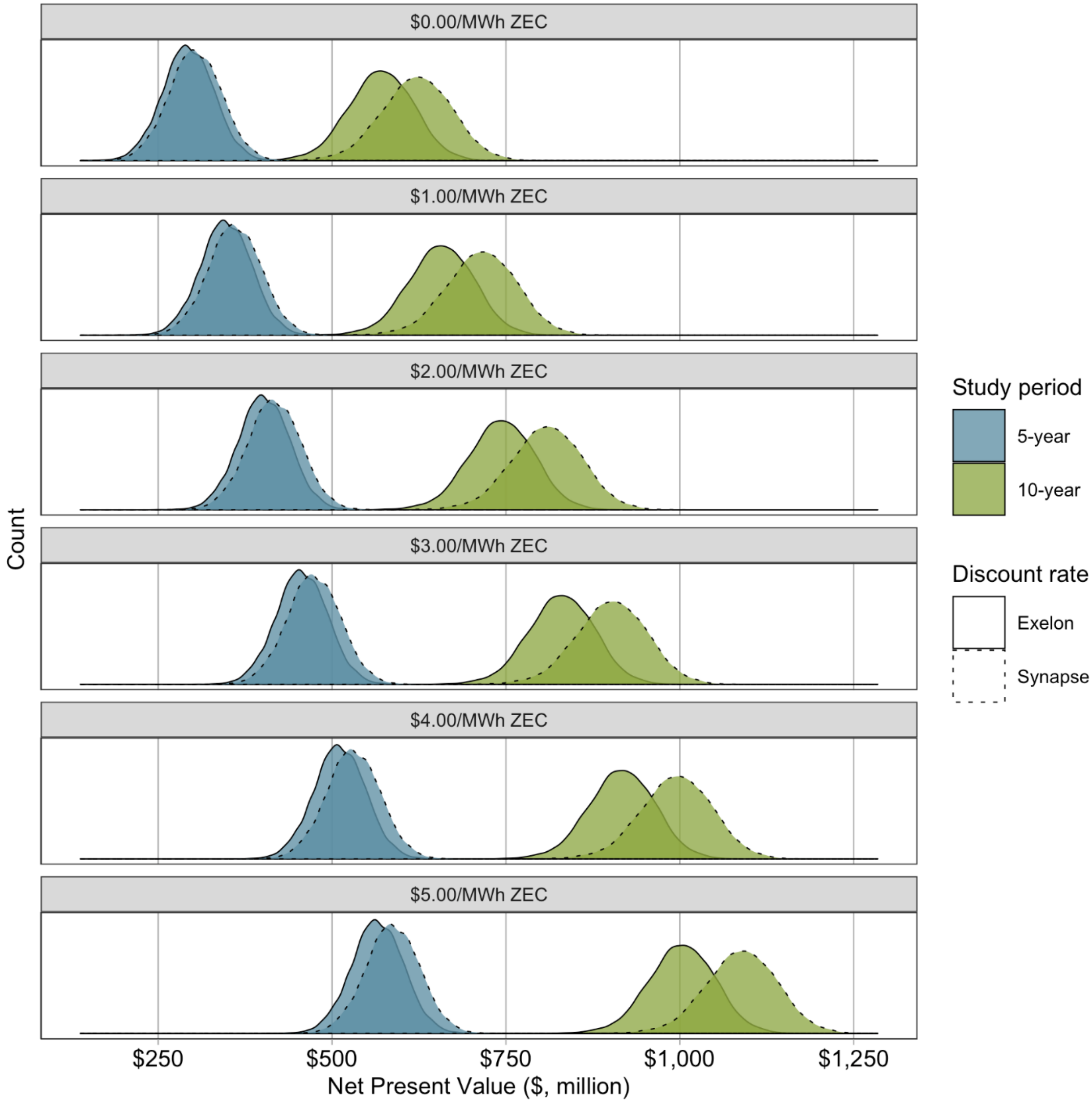
Source: Synapse Energy Economics model—Monte Carlo analysis using Exelon expense forecast with adjustments, Synapse energy and capacity revenues forecast (Synapse internal production cost and capacity expansion model), and uncertainty distributions derived from historical market and operational data.

Figure 28. Braidwood expected net present value cash flow, Baseline Scenario—Monte Carlo simulations ($,million) [5th–95th percentile]

ZEC	10-Year Study Period Monte Carlo NPV Results		5-Year Study Period Monte Carlo NPV Results	
($/MWh)	Synapse Discount Rate	Exelon Discount Rate	Synapse Discount Rate	Exelon Discount Rate
0.0	334 [245 - 417]	297 [215 - 375]	72 [7 - 136]	69 [7 - 131]
0.5	381 [293 - 465]	341 [259 - 419]	101 [36 - 165]	97 [34 - 159]
1.0	429 [340 - 513]	385 [303 - 463]	130 [65 - 194]	125 [62 - 187]
1.5	476 [388 - 561]	429 [347 - 507]	159 [94 - 223]	153 [90 - 215]
2.0	524 [435 - 608]	473 [391 - 551]	188 [122 - 253]	180 [117 - 242]
2.5	572 [483 - 656]	517 [435 - 596]	217 [151 - 282]	208 [145 - 270]
3.0	619 [530 - 704]	561 [479 - 640]	246 [180 - 311]	236 [173 - 298]
3.5	667 [578 - 752]	605 [523 - 684]	275 [209 - 340]	264 [200 - 326]
4.0	715 [625 - 799]	649 [567 - 728]	304 [237 - 369]	291 [228 - 354]
4.5	762 [673 - 847]	694 [611 - 773]	333 [266 - 398]	319 [255 - 382]
5.0	810 [720 - 895]	738 [655 - 817]	361 [295 - 427]	347 [283 - 410]
5.5	858 [768 - 943]	782 [699 - 861]	390 [324 - 456]	375 [311 - 438]
6.0	905 [815 - 991]	826 [743 - 905]	419 [352 - 485]	402 [338 - 466]
10.0	1,286 [1,195 - 1,372]	1,179 [1,095 - 1,259]	651 [583 - 718]	624 [559 - 689]
16.5	1,905 [1,812 - 1,994]	1,752 [1,666 - 1,834]	1,027 [957 - 1,096]	985 [918 - 1,051]

Source: Synapse Energy Economics model—Monte Carlo analysis using Exelon expense forecast with adjustments, Synapse energy and capacity revenues forecast (Synapse internal production cost and capacity expansion model), and uncertainty distributions derived from historical market and operational data.

Figure 29. LaSalle net present value cash flow, Baseline Scenario—Monte Carlo simulations



Source: Synapse Energy Economics model—Monte Carlo analysis using Exelon expense forecast with adjustments, Synapse energy and capacity revenues forecast (Synapse internal production cost and capacity expansion model), and uncertainty distributions derived from historical market and operational data.

Figure 30. LaSalle expected net present value cash flow, Baseline Scenario—Monte Carlo simulations ($, million) [5th–95th percentile]

ZEC	10-Year Study Period Monte Carlo NPV Results		5-Year Study Period Monte Carlo NPV Results	
($/MWh)	Synapse Discount Rate	Exelon Discount Rate	Synapse Discount Rate	Exelon Discount Rate
0.0	622 [538 - 703]	570 [492 - 646]	303 [240 - 365]	293 [232 - 353]
0.5	668 [584 - 750]	613 [536 - 689]	332 [268 - 394]	320 [260 - 380]
1.0	715 [631 - 797]	657 [579 - 732]	360 [297 - 422]	348 [287 - 407]
1.5	762 [678 - 843]	700 [622 - 775]	388 [325 - 451]	375 [314 - 435]
2.0	808 [724 - 890]	743 [665 - 819]	417 [353 - 479]	402 [341 - 462]
2.5	855 [771 - 937]	786 [708 - 862]	445 [382 - 508]	429 [368 - 489]
3.0	902 [817 - 984]	830 [751 - 906]	474 [410 - 536]	456 [395 - 516]
3.5	949 [864 - 1,031]	873 [794 - 949]	502 [438 - 565]	484 [422 - 544]
4.0	995 [910 - 1,077]	916 [838 - 992]	530 [466 - 593]	511 [450 - 571]
4.5	1,042 [957 - 1,124]	959 [881 - 1,036]	559 [495 - 622]	538 [477 - 598]
5.0	1,089 [1,003 - 1,171]	1,003 [924 - 1,079]	587 [523 - 650]	565 [504 - 626]
5.5	1,135 [1,050 - 1,218]	1,046 [967 - 1,122]	616 [551 - 679]	593 [531 - 653]
6.0	1,182 [1,096 - 1,264]	1,089 [1,010 - 1,166]	644 [580 - 707]	620 [558 - 680]
10.0	1,556 [1,469 - 1,639]	1,435 [1,355 - 1,512]	871 [806 - 935]	838 [775 - 899]
16.5	2,162 [2,074 - 2,247]	1,997 [1,916 - 2,076]	1,240 [1,173 - 1,306]	1,191 [1,127 - 1,254]

Source: Synapse Energy Economics model—Monte Carlo analysis using Exelon expense forecast with adjustments, Synapse energy and capacity revenues forecast (Synapse internal production cost and capacity expansion model), and uncertainty distributions derived from historical market and operational data.

Appendix H. CARBON PRICE SCENARIO

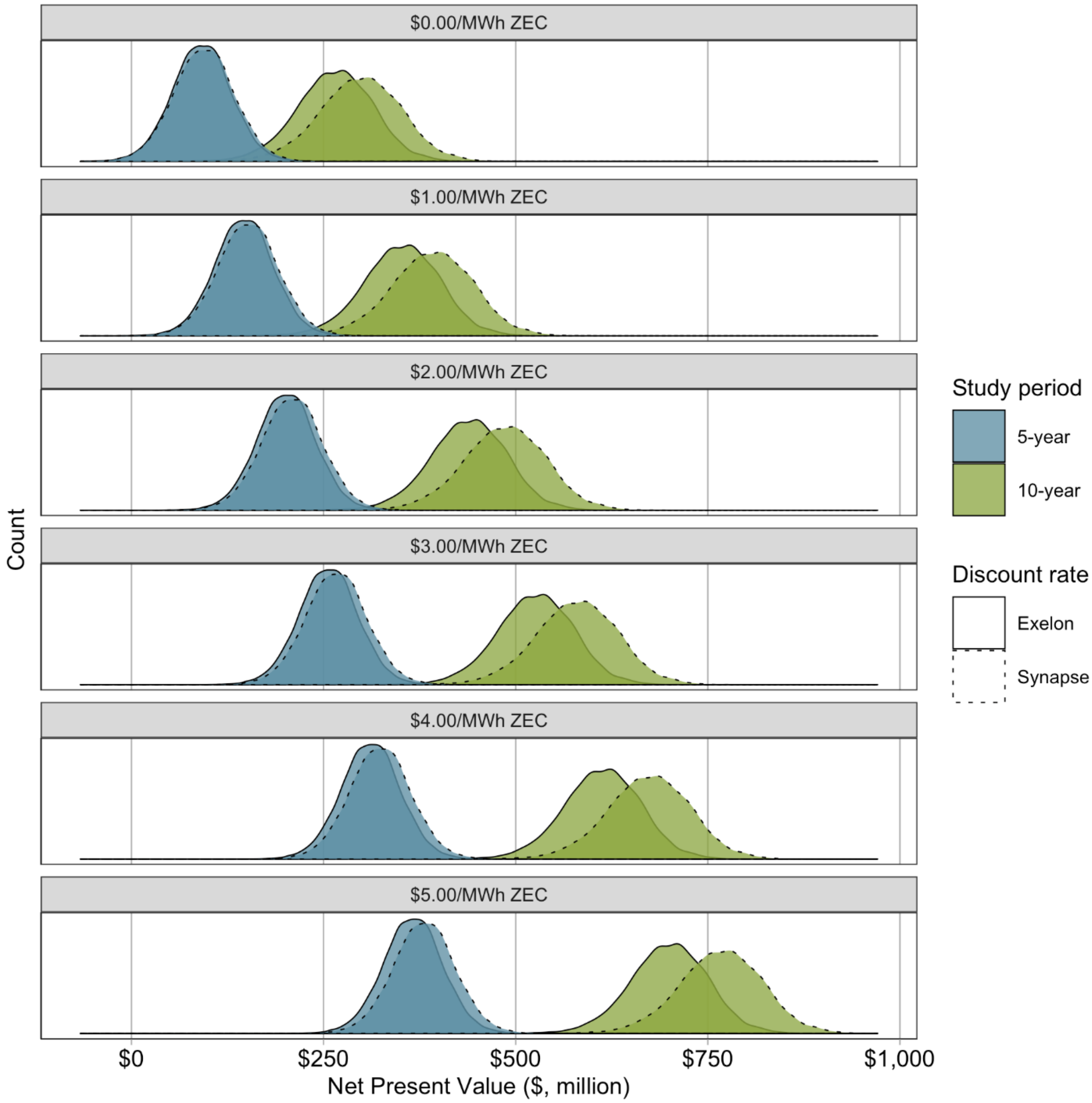
This appendix includes Monte Carlo results for a carbon pricing scenario. The scenario assumes carbon pricing at values similar to Illinois entering RGGI, a program which places a price on carbon through a regional cap-and-trade system. Figure 32 through Figure 38 and Figure 31 through Figure 37 below provide detailed plant-level results under this scenario.

Adding carbon pricing at values similar to RGGI is expected to result in a positive NPV for Byron, although Dresden's NPV remains negative. Byron has positive NPVs in 99 percent of simulations with a ZEC value of $0/MWh in the 5-year analysis with the Exelon discount rate. Adding a ZEC price of $2.5/MWh (in addition to carbon pricing) results in a positive 5-year NPVs for 95 percent of simulations for Dresden. No subsidies were required to support Byron and Dresden when we expanded the Carbon Price Scenario to a 10-year study period.[104]

[104] Dresden Unit 2 was still assumed to retire in 2029 under the Carbon Price Scenario, which may skew the 10 -year analysis.

Byron

Figure 31. Byron net present value cash flow, Carbon Price Scenario—Monte Carlo simulations



Source: Synapse Energy Economics model—Monte Carlo analysis using Exelon expense forecast with adjustments, Synapse energy and capacity revenues forecast (Synapse internal production cost and capacity expansion model), and uncertainty distributions derived from historical market and operational data.

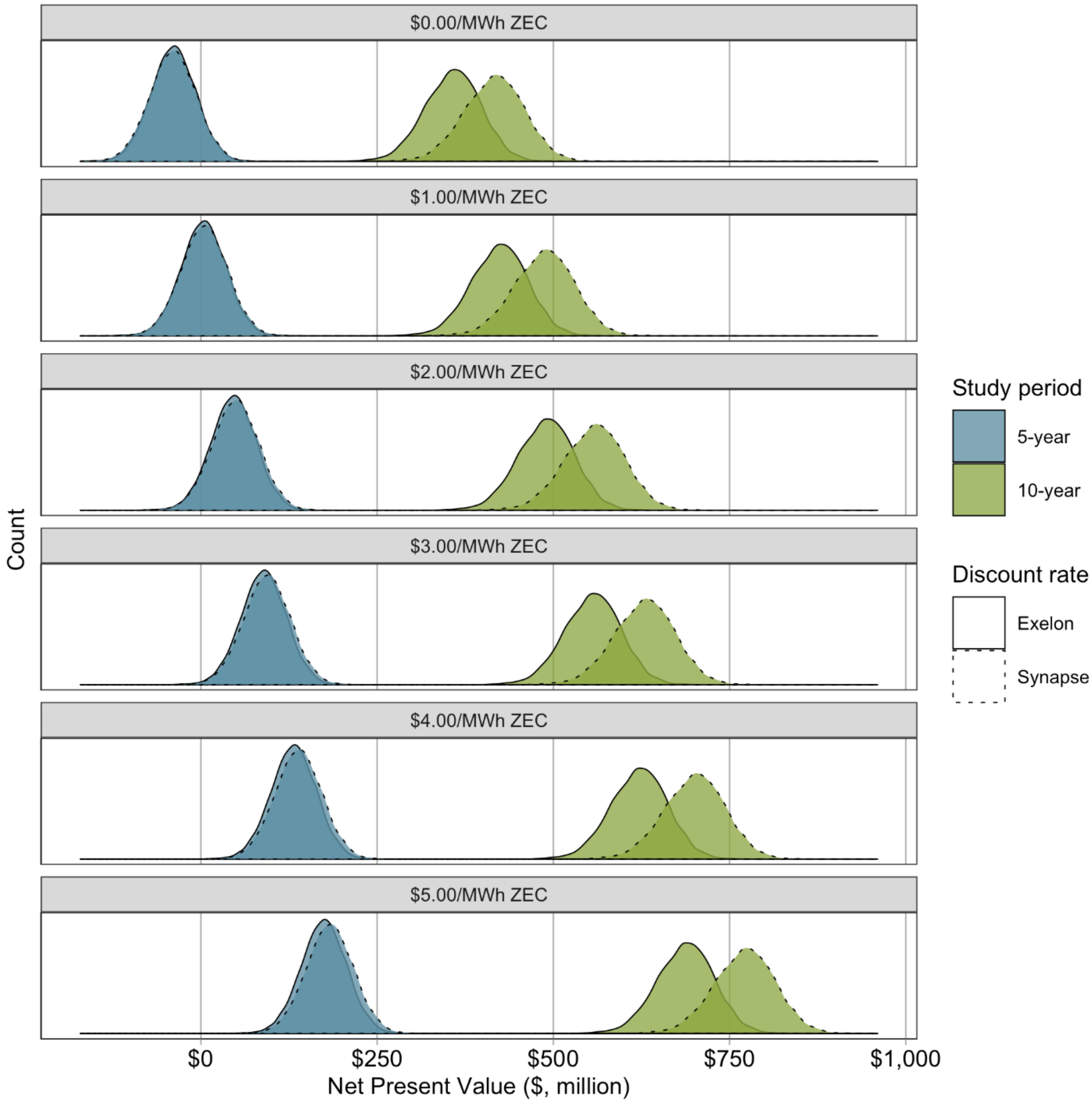
Figure 32. Byron expected net present value cash flow, carbon pricing scenario—Monte Carlo simulations ($, million) [5th–95th percentile]

ZEC	10-Year Study Period Monte Carlo NPV Results		5-Year Study Period Monte Carlo NPV Results	
($/MWh)	Synapse Discount Rate	Exelon Discount Rate	Synapse Discount Rate	Exelon Discount Rate
0.0	298 [207 - 383]	264 [181 - 343]	94 [29 - 159]	91 [28 - 153]
0.5	345 [254 - 430]	308 [225 - 387]	123 [57 - 187]	119 [56 - 181]
1.0	391 [301 - 477]	351 [268 - 430]	151 [86 - 216]	146 [83 - 208]
1.5	438 [348 - 524]	395 [312 - 474]	180 [115 - 245]	174 [110 - 236]
2.0	485 [395 - 571]	438 [355 - 518]	209 [143 - 274]	201 [138 - 263]
2.5	532 [441 - 618]	482 [398 - 561]	237 [172 - 302]	229 [165 - 291]
3.0	579 [488 - 665]	525 [442 - 605]	266 [200 - 331]	256 [193 - 319]
3.5	626 [535 - 712]	569 [485 - 649]	295 [229 - 360]	284 [220 - 346]
4.0	673 [582 - 759]	612 [529 - 692]	323 [257 - 389]	311 [247 - 374]
4.5	720 [629 - 806]	656 [572 - 736]	352 [286 - 418]	339 [275 - 401]
5.0	767 [676 - 853]	699 [615 - 779]	381 [314 - 447]	366 [302 - 429]
5.5	814 [723 - 900]	743 [659 - 823]	409 [343 - 475]	394 [330 - 457]
6.0	861 [769 - 947]	786 [702 - 867]	438 [372 - 504]	421 [357 - 484]
10.0	1,236 [1,144 - 1,324]	1,134 [1,049 - 1,216]	667 [600 - 734]	641 [576 - 705]
16.5	1,847 [1,752 - 1,936]	1,699 [1,613 - 1,782]	1,040 [971 - 1,108]	998 [932 - 1,064]

Source: Synapse Energy Economics model—Monte Carlo analysis using Exelon expense forecast with adjustments, Synapse energy and capacity revenues forecast (Synapse internal production cost and capacity expansion model), and uncertainty distributions derived from historical market and operational data.

Dresden

Figure 33. Dresden net present value cash flow, Carbon Price Scenario—Monte Carlo simulations



Source: Synapse Energy Economics model—Monte Carlo analysis using Exelon expense forecast with adjustments, Synapse energy and capacity revenues forecast (Synapse internal production cost and capacity expansion model), and uncertainty distributions derived from historical market and operational data.

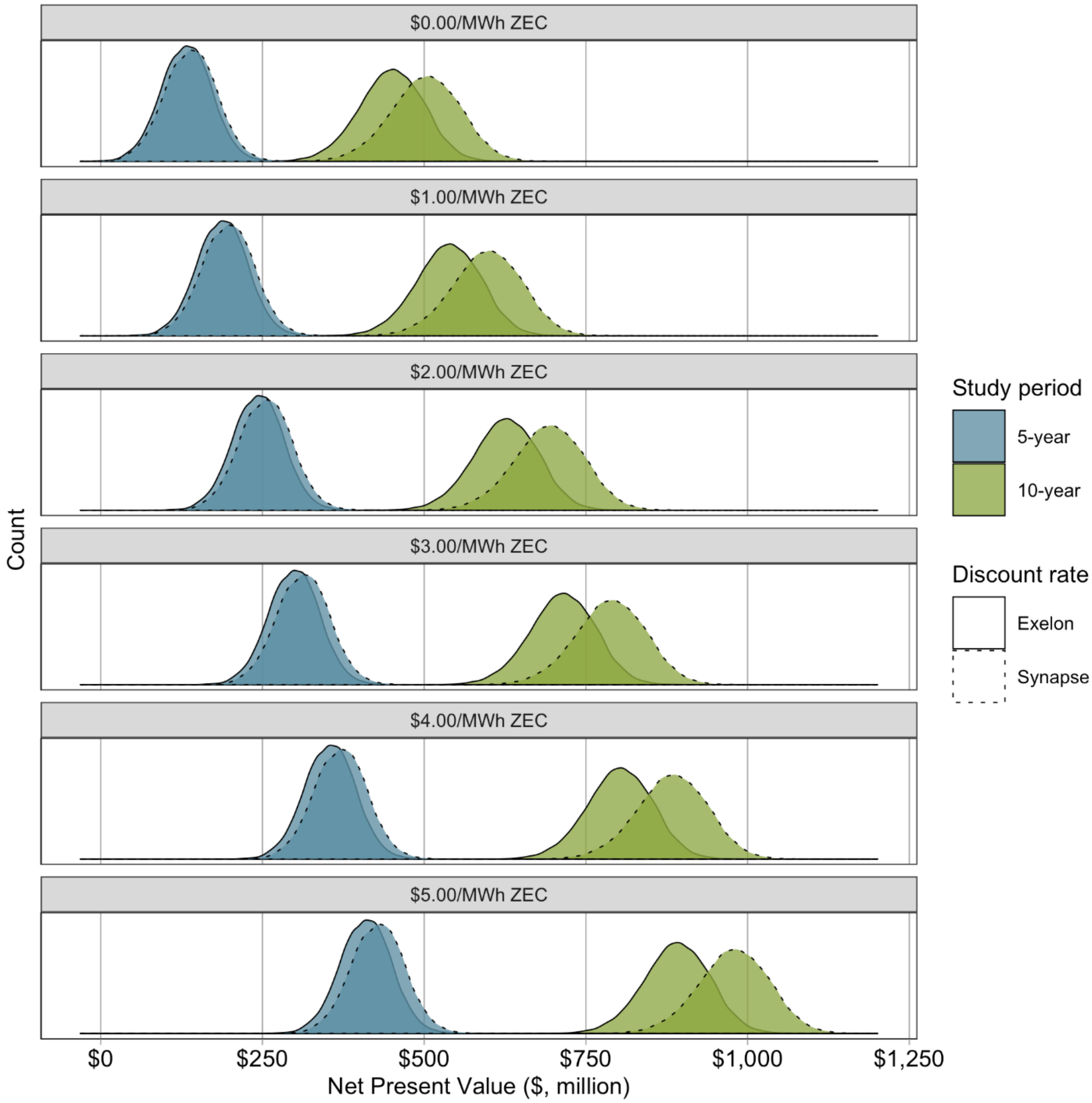
Figure 34. Dresden expected net present value cash flow, carbon pricing scenario—Monte Carlo simulations ($, million) [5th–95th percentile]

ZEC	10-Year Study Period Monte Carlo NPV Results		5-Year Study Period Monte Carlo NPV Results	
($/MWh)	Synapse Discount Rate	Exelon Discount Rate	Synapse Discount Rate	Exelon Discount Rate
0.0	416 [344 - 485]	357 [290 - 421]	-40 [-95 - 14]	-39 [-92 - 13]
0.5	451 [379 - 520]	390 [323 - 454]	-18 [-73 - 37]	-18 [-71 - 34]
1.0	487 [414 - 556]	423 [356 - 488]	5 [-50 - 59]	4 [-49 - 56]
1.5	523 [450 - 592]	456 [389 - 521]	27 [-28 - 82]	25 [-28 - 77]
2.0	558 [485 - 627]	489 [422 - 554]	49 [-6 - 104]	46 [-7 - 99]
2.5	594 [521 - 663]	522 [455 - 587]	71 [16 - 126]	68 [14 - 120]
3.0	629 [556 - 698]	555 [488 - 620]	94 [38 - 149]	89 [36 - 141]
3.5	665 [592 - 734]	588 [521 - 653]	116 [61 - 171]	110 [57 - 163]
4.0	700 [627 - 770]	621 [553 - 686]	138 [83 - 193]	132 [78 - 184]
4.5	736 [663 - 805]	654 [586 - 719]	160 [105 - 216]	153 [99 - 206]
5.0	771 [698 - 841]	687 [619 - 752]	183 [127 - 238]	174 [121 - 227]
5.5	807 [733 - 877]	720 [652 - 786]	205 [149 - 260]	196 [142 - 249]
6.0	842 [769 - 912]	753 [685 - 819]	227 [171 - 283]	217 [163 - 270]
10.0	1,127 [1,052 - 1,198]	1,018 [949 - 1,083]	405 [348 - 461]	388 [333 - 441]
16.5	1,589 [1,513 - 1,661]	1,447 [1,377 - 1,514]	694 [636 - 752]	665 [609 - 720]

Source: Synapse Energy Economics model—Monte Carlo analysis using Exelon expense forecast with adjustments, Synapse energy and capacity revenues forecast (Synapse internal production cost and capacity expansion model), and uncertainty distributions derived from historical market and operational data.

Braidwood

Figure 35. Braidwood net present value cash flow, Carbon Price Scenario—Monte Carlo simulations



Source: Synapse Energy Economics model—Monte Carlo analysis using Exelon expense forecast with adjustments, Synapse energy and capacity revenues forecast (Synapse internal production cost and capacity expansion model), and uncertainty distributions derived from historical market and operational data.

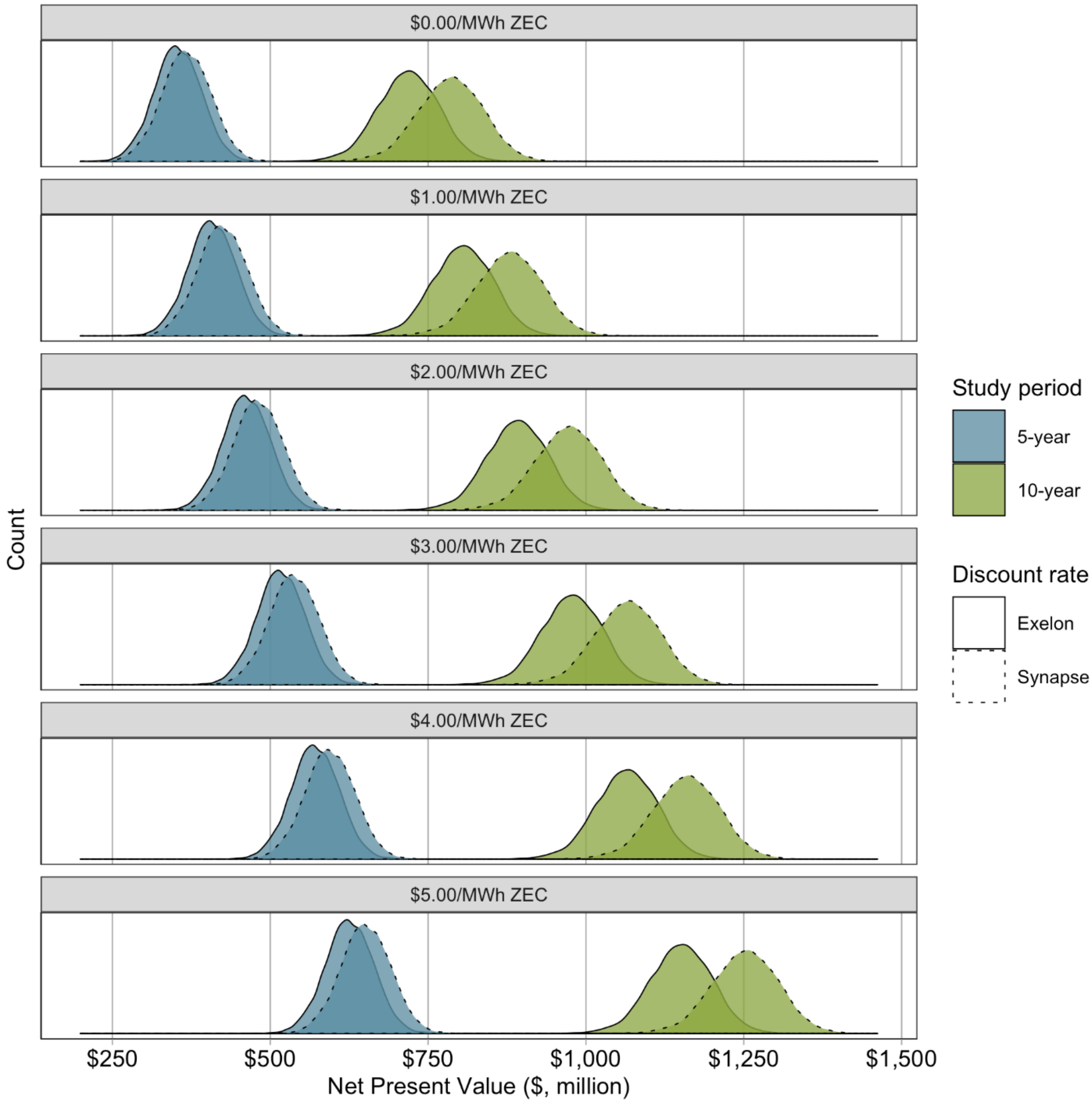
Figure 36. Braidwood expected net present value cash flow, carbon pricing scenario—Monte Carlo simulations ($, million) [5th–95th percentile]

ZEC	10-Year Study Period Monte Carlo NPV Results		5-Year Study Period Monte Carlo NPV Results	
($/MWh)	Synapse Discount Rate	Exelon Discount Rate	Synapse Discount Rate	Exelon Discount Rate
0.0	502 [411 - 589]	449 [365 - 529]	139 [72 - 205]	132 [68 - 195]
0.5	550 [459 - 637]	493 [409 - 573]	168 [101 - 234]	160 [96 - 223]
1.0	598 [506 - 684]	537 [453 - 617]	197 [130 - 263]	188 [123 - 251]
1.5	645 [554 - 732]	581 [497 - 662]	226 [159 - 292]	215 [151 - 279]
2.0	693 [601 - 780]	626 [541 - 706]	255 [188 - 321]	243 [179 - 307]
2.5	740 [649 - 828]	670 [585 - 750]	284 [217 - 350]	271 [206 - 335]
3.0	788 [696 - 875]	714 [629 - 795]	313 [246 - 379]	299 [234 - 362]
3.5	836 [744 - 923]	758 [673 - 839]	342 [274 - 408]	326 [262 - 390]
4.0	883 [791 - 971]	802 [717 - 883]	371 [303 - 437]	354 [289 - 418]
4.5	931 [839 - 1,018]	846 [761 - 927]	399 [332 - 466]	382 [317 - 446]
5.0	979 [886 - 1,066]	890 [805 - 972]	428 [361 - 495]	410 [345 - 474]
5.5	1,026 [934 - 1,114]	934 [849 - 1,016]	457 [389 - 524]	437 [372 - 502]
6.0	1,074 [981 - 1,162]	979 [893 - 1,060]	486 [418 - 553]	465 [400 - 530]
10.0	1,455 [1,361 - 1,544]	1,331 [1,245 - 1,414]	718 [648 - 786]	687 [621 - 753]
16.5	2,074 [1,978 - 2,165]	1,905 [1,817 - 1,989]	1,094 [1,023 - 1,164]	1,048 [979 - 1,115]

Source: Synapse Energy Economics model—Monte Carlo analysis using Exelon expense forecast with adjustments, Synapse energy and capacity revenues forecast (Synapse internal production cost and capacity expansion model), and uncertainty distributions derived from historical market and operational data.

Lasalle

Figure 37. LaSalle net present value cash flow, Carbon Price Scenario—Monte Carlo simulations



Source: Synapse Energy Economics model—Monte Carlo analysis using Exelon expense forecast with adjustments, Synapse energy and capacity revenues forecast (Synapse internal production cost and capacity expansion model), and uncertainty distributions derived from historical market and operational data.

Figure 38. LaSalle expected net present value cash flow, carbon pricing scenario—Monte Carlo simulations ($, million) [5th–95th percentile]

ZEC	10-Year Study Period Monte Carlo NPV Results		5-Year Study Period Monte Carlo NPV Results	
($/MWh)	Synapse Discount Rate	Exelon Discount Rate	Synapse Discount Rate	Exelon Discount Rate
0.0	785 [700 - 869]	718 [638 - 795]	367 [303 - 430]	353 [291 - 414]
0.5	832 [746 - 915]	761 [681 - 839]	396 [331 - 459]	380 [318 - 441]
1.0	879 [793 - 962]	804 [725 - 882]	424 [359 - 488]	408 [346 - 469]
1.5	925 [839 - 1,009]	848 [768 - 925]	452 [388 - 516]	435 [373 - 496]
2.0	972 [886 - 1,055]	891 [811 - 969]	481 [416 - 545]	462 [400 - 523]
2.5	1,019 [933 - 1,102]	934 [854 - 1,012]	509 [444 - 573]	489 [427 - 550]
3.0	1,065 [979 - 1,149]	977 [897 - 1,055]	538 [472 - 602]	516 [454 - 578]
3.5	1,112 [1,026 - 1,196]	1,021 [940 - 1,099]	566 [501 - 630]	544 [481 - 605]
4.0	1,159 [1,072 - 1,242]	1,064 [984 - 1,142]	594 [529 - 658]	571 [508 - 632]
4.5	1,205 [1,119 - 1,289]	1,107 [1,027 - 1,185]	623 [557 - 687]	598 [535 - 660]
5.0	1,252 [1,166 - 1,336]	1,150 [1,070 - 1,229]	651 [586 - 715]	625 [563 - 687]
5.5	1,299 [1,212 - 1,383]	1,194 [1,113 - 1,272]	680 [614 - 744]	653 [590 - 714]
6.0	1,346 [1,258 - 1,430]	1,237 [1,156 - 1,316]	708 [642 - 772]	680 [617 - 742]
10.0	1,719 [1,631 - 1,804]	1,583 [1,501 - 1,663]	935 [868 - 1,001]	898 [833 - 960]
16.5	2,326 [2,236 - 2,413]	2,145 [2,062 - 2,226]	1,304 [1,236 - 1,371]	1,251 [1,186 - 1,316]

Source: Synapse Energy Economics model—Monte Carlo analysis using Exelon expense forecast with adjustments, Synapse energy and capacity revenues forecast (Synapse internal production cost and capacity expansion model), and uncertainty distributions derived from historical market and operational data.