City of Batavia Integrated Resource Plan

DRAFT REPORT UPDATE

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CITY OF BATAVIA

DISCLAIMER

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Key Observations

1. This Integrated Resource Plan (IRP) is intended to help guide the City of Batavia (City, or Batavia) identify actionable near-term strategies and inform longer-term planning efforts to ensure reliability, maximize energy affordability, and meet local and state energy policy requirements.
2. Batavia has experienced no load growth since 2018, and the City's 55-MW supply contract with the Northern Illinois Municipal Power Agency (NIMPA) provides more than enough energy for Batavia's needs. However, the mismatch in electricity supply and demand profile leaves Batavia exposed to volatile prices in the PJM energy and capacity markets.
3. Batavia's demand will likely remain stable over the next two decades, though policy changes, high fossil fuel prices, and increases in industrial demand (either from existing or new customers) could induce electrification and higher demand for electricity.
4. We expect increasing global demand for liquified natural gas (LNG) to drive up natural gas prices and electricity prices in the near term. Capacity prices are projected to increase in the 2030s. The combined effects would leave Batavia exposed to high energy and capacity costs. The projected increase in capacity prices is 3x - 5x higher than historical levels.
5. Based on our projections, Batavia's biggest cost risk will be from capacity market payments. While the 55-MW NIMPA contract largely mitigates its exposure to energy price risk, about half of Batavia's capacity obligation to serve its 85 MW peak load is still exposed. We recommend Batavia to prioritize choosing resources that reduce its reliance on capacity market purchases.
6. Procuring additional generation or storage resources or investing in demand reduction programs could reduce Batavia's exposure to high market prices, particularly for capacity. We evaluated resources that could be suitable given Batavia's location, size, customer makeup, and other parameters.
7. A natural gas reciprocating engine (RECIP) deployed in in the late 2020s (as early as possible) may be the best option for reducing Batavia's exposure to capacity market risk. This finding is robust across different scenarios and assumptions for federal tax credits.
8. We recommend Batavia to explore smart thermostat, Time of Usage (TOU) rates, and electric vehicles (EV) managed charging programs, which can further help to reduce exposure to volatile market prices, especially as the potential participant base grows.
9. We also considered Batavia-specific external factors, including its customer preferences and city and state policies, in drafting recommendations.

The recommended five-year action plan reflects all of above.

Key Terms and Conventions

Watt-hours, Kilowatt-hours, Megawatt-hours, Gigawatt-hours, and Terawatt-hours (Wh, kWh, MWh, GWh, TWh) measure electrical **energy** generation or consumption over time. Electrical energy produced or consumed at a rate of 1 megawatt for one hour is equal to one megawatt-hour of generation or consumption. **Energy consumption** or **energy usage** (sometimes referred to as “sales”), measured in kWh, MWh, GWh, or TWh, refers to the total amount of electrical energy consumed over a given time period. A typical household in the greater Chicago area is estimated to consume ~7 to 9 MWh (7,000 to 9,000 kWh) annually. In the PJM Interconnection, energy is traded in the Energy Market on an hourly basis.

Watts, Kilowatts, Megawatts, Gigawatts, and Terawatts (W, kW, MW, GW, TW) are instantaneous measure of units of power. **Load** or **peak load**, which are measured in MW or GW, refers to the highest single momentary demand for electricity. **Capacity** needed to serve that **load** or **peak load**, is also measured in MW or GW.

Load serving entities, including Batavia, are required to secure enough generation **capacity** to serve their peak load (including capacity reserve margins that are added to a load serving entity’s estimated peak load). PJM procures the needed capacity through annual capacity auctions (**Capacity Market**), called the **Reliability Pricing Model (RPM)**. PJM then allocates the costs of procuring all capacity to individual load serving entities.

PJM Interconnection (PJM), originally the Pennsylvania–New Jersey–Maryland Interconnection, is the regional transmission organization (RTO) serving the Mid-Atlantic and portions of the Midwest, including Commonwealth Edison (ComEd) that serves the greater Chicago area. **PJM** operates the bulk electric system, administers wholesale electricity markets, and determines capacity obligations needed to maintain reliability. As a member of the **PJM** region, Batavia's resource planning is influenced by **PJM** energy prices, capacity obligations, and market rules.

Electric forecasters must plan to meet both sales needs (typically measured in MWh or GWh units) over time and to meet peak loads (typically measured in MW or GW units), and we discuss both units in parallel throughout this report. When referring to both sales and peak loads together, we generally use the term **electricity demand**.

Load forecast refers to projections for electricity demand.

Net Cost of New Entry (Net CONE) is the cost of developing and operating new power generation resources, offset by its anticipated net revenues from the energy and ancillary service markets. In other words, it is the amount of money needed to support new generation capacity. Net CONE is one of the key inputs to determine the expected clearing price for the capacity market under long-term equilibrium conditions.

British Thermal Units (Btu), typically expressed in millions **(MMBtu)**, are units of heat energy. Natural gas prices are often quoted in $/MMBtu, or the cost of the amount of gas required to produce one million Btus of heat if burned.

Scenario represents a set of future conditions reflecting an internally-consistent set of assumptions about Batavia’s electricity demand, natural gas and capacity prices, and resource investment costs.

Case refers to individual drivers comprising each scenario, including electricity demand, natural gas prices, capacity prices, and technology costs.

For simplicity, we assume all years follow the same calendar structure as 2024—specifically, January 1 falls on a Monday in all modeled years.

Key Observation 1a: IRP Objectives

This Integrated Resource Plan (IRP) is intended to help guide the City of Batavia in identifying actionable near -term strategies and informing longer-term planning efforts to ensure reliability, maximize energy affordability, and meet state energy policy requirements. The IRP includes a reference scenario and two additional scenarios representing higher and lower load growth and resulting market prices.

This IRP is intended to serve as a roadmap rather than a fixed blueprint. Illinois' Public Act 104 -0458 requires utilities to review and update the plan approximately every five years, or sooner, if major changes in market conditions, regulations, technology, or customer needs warrant a reassessment.

To inform our selection of the preferred resource portfolio, we calculate the net present value of costs to serve Batavia's bad while pursuing a least-regrets plan (i.e., avoid the portfolios with high-cost risks) for each resource portfolio.

Key Analytical Steps

1. Identify future energy and capacity needs

- Develop load forecast based on Batavia's existing customer base and changes to residential, commercial and industrial (C&I) customer characteristics
- Account for load drivers such as electric vehicle (EV) charging and adoption of distributed energy resources (DERs)

2. Compare costs of alternative resource portfolios

- Project PJM energy and capacity prices at Batavia's location
- Evaluate costs and potential upsides of new solar, wind, battery, and gas RECIP units
- Evaluate costs and benefits of demand-side resources

3. Scenario analysis to evaluate exposure to risks

- Identify key uncertainties (load growth and timing, state legislation and requirements, EV and DER adoption, fuel prices, capacity prices)
- Develop scenarios with internally consistent set of sensitivities

Key Observation 1b: IRP Scenarios

To assess the lifecycle costs and revenues to serve Batavia's load with different supply-side and demand-side resources, we projected prices, consumer behavior, and macroeconomic trends across three scenarios.

Driven primarily by Batavia's load and natural gas market prices, these scenarios represent a range of possible future condit ions Batavia can encounter. Testing the recommendations and assessments in this report across all three scenarios can illustrate how Batavia's potential needs and strategies for meeting them can change across potential future conditions. It also helps validate the robustness of the recommendations and assessments in this report.

Key Variable Definitions Across IRP Scenarios

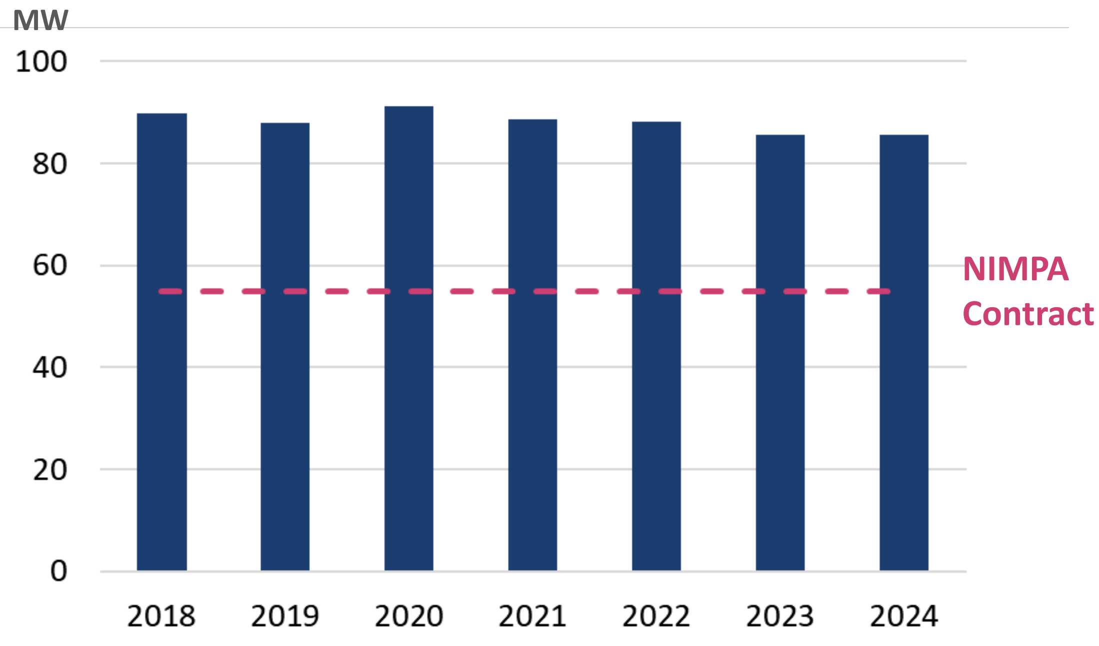
Scenario Name	Load Case	EV Adoption Rates	Rooftop Solar Adoption Rates	Natural Gas Price Case	IMHR* Case	ComEd Capacity Price Case	Technology Cost Trend
Reference	Base	Base	Base	Base	Base	Low	Base
High Market Price	Low	Low	High	High	Low	High	Faster Cost Reduction
Low Market Price	High	High	Low	Low	High	Low	Slower Cost Reduction

Note: Implied Market Heat Rate (IMHR) is an indicator of the relative market prices of electricity and the price of the marginal fuel, which we assume to remain natural gas throughout the foreseeable future (i.e., electricity price divided by natural gas price). Higher IMHR values generally indicate stronger market conditions for gas-fired power generation and can lead to higher energy market revenues, while lower IMHR values indicate weaker market conditions and lower expected revenues.

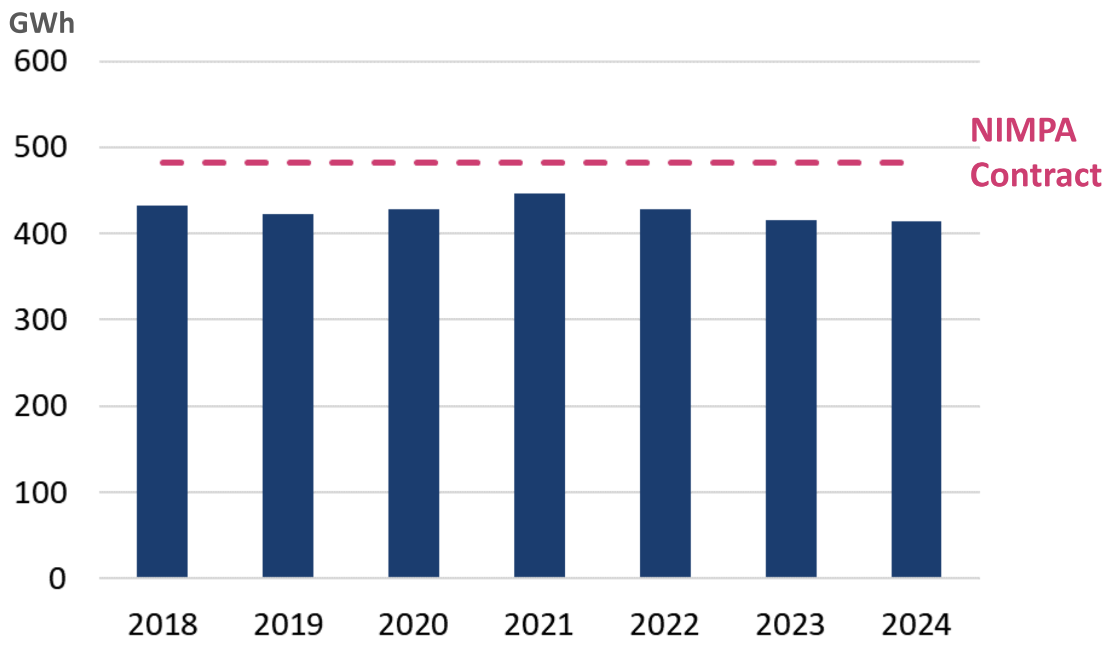
Key Observation 2a: Historical Load Growth

Batavia has experienced no load growth since 2018, and its NIMPA contract provides more than enough supply for Batavia's annual energy needs.
Batavia's 2024 peak load (which represents the highest hourly demand observed during the year) was 85.5 MW, compared to 89.7 MW in 2018.
Similarly, Batavia's annual energy consumption decreased from 432.9 GWh in 2018 to 414.5 GWh in 2024.
The NIMPA contract provides 55 MW (~482 GWh annually) of supply.

Historical Annual Metered Peak Load



Historical Annual Metered Consumption



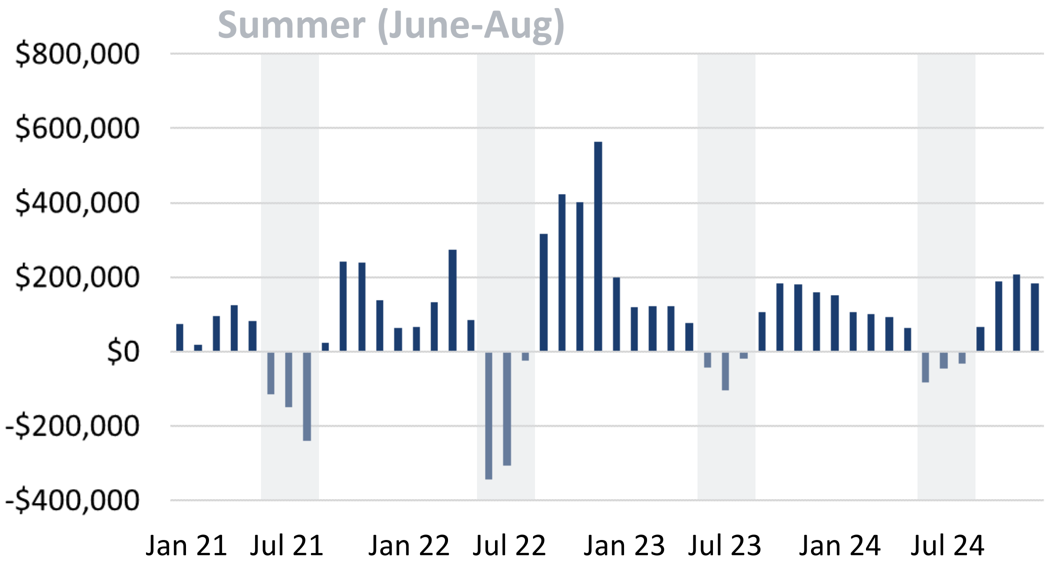
Notes: Also known as "net load" and "net consumption", metered load and metered consumption are net of behind-the-meter generation (e.g., rooftop solar photovoltaic).

Key Observation 2b: Monthly Exposure to Market Prices

A mismatch between the NIMPA supply profile and Batavia's demand profile leaves Batavia exposed to volatile prices of the PJMenergy and capacity markets. Batavia's electricity demand tends to exceed the 55 MW supply provided by the NIMPA contract in hours and months when electricity prices tend to be high (e.g., summer months). To meet the shortfall, Batavia relies on market purchases and incurs net energy costs in those months.

Since 2018, the difference in Batavia's peak load and the 55 MW capacity from the NIMPA contract ranged between 31-35 MW (see previous slide). Batavia pays PJM to cover this capacity shortfall. Any increase in PJM capacity price in the future will magnify Batavia's exposure to capacity market risk.

Batavia Monthly Net Energy Market Revenue (Cost)



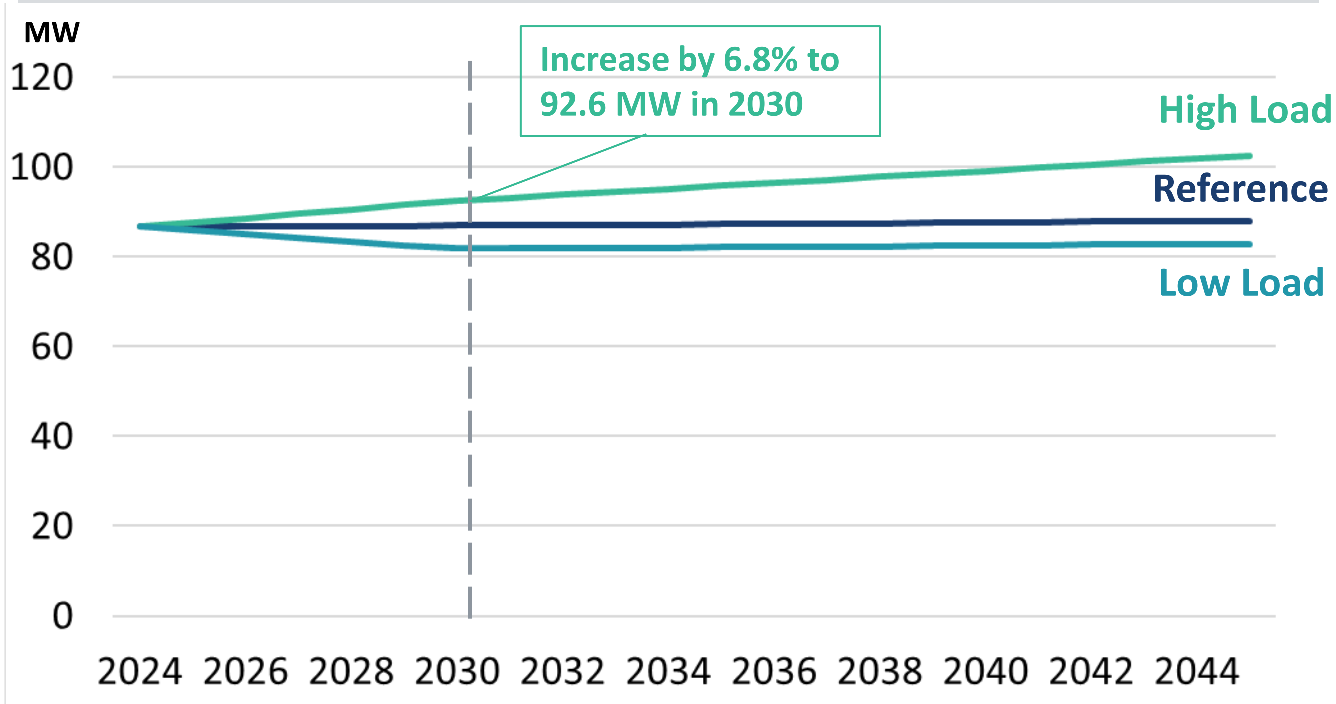
Sources and notes: Reflects energy market purchases and sales net of 55 MW NIMPA contract (in nom. dollars). Calculated using PJM Day-Ahead hourly LMPs at Batavia node from Energy Ventyx, Velocity Suite and Batavia hourly consumption data.

Key Observation 3: Forecasted Load Growth

Batavia's load will likely remain stable over the next two decades, though policy changes, high fossil fuel prices, and increases in industrial load (either from existing or new customers) could induce electrification and higher demand for electricity. In the High Load case, we find that Batavia's gross system load could increase by 6.8% to 92.6 MW by 2030 and exceed 100 MW by 2045.

This load forecast does not include the 50 MW data center, which is currently under development. Batavia plans this new data center to be served through market purchases with all costs being paid by the data center.

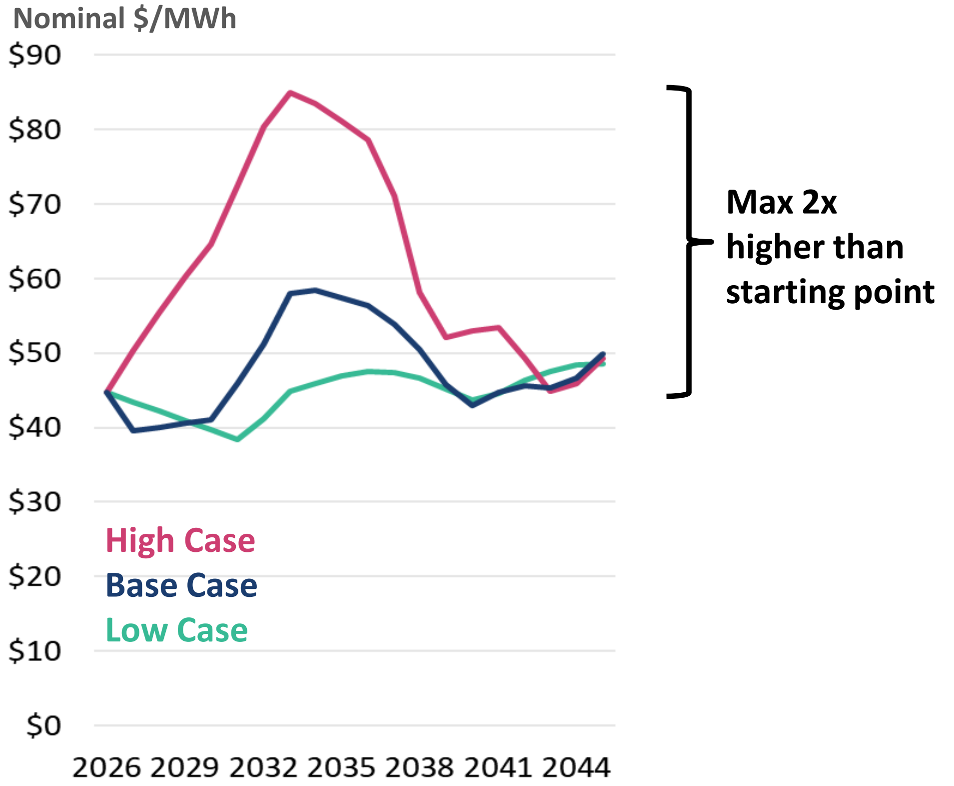
Batavia Gross Load Cases (2024-2045)



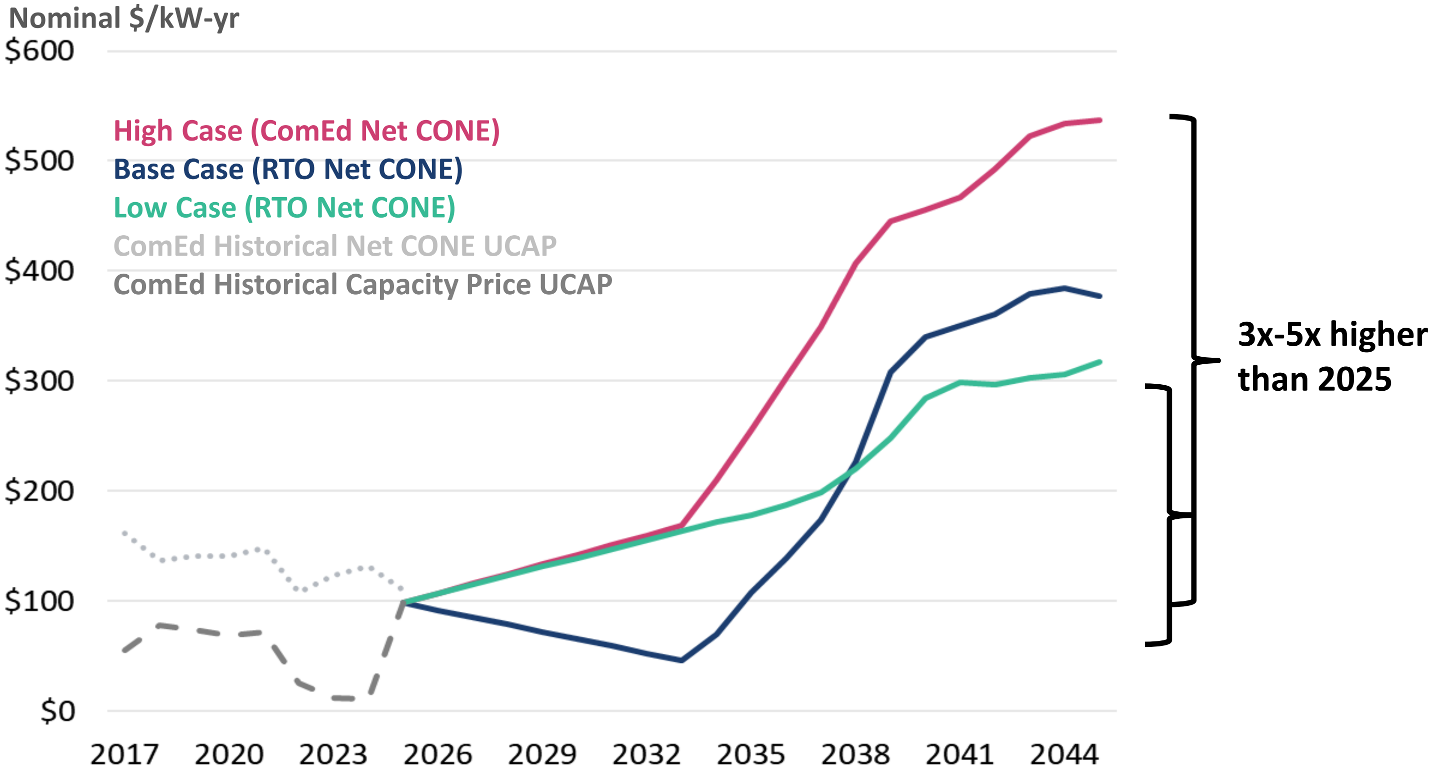
Key Observation 4: Market Price Outlooks

We expect increasing global demand for liquified natural gas (LNG) to drive up natural gas prices and energy prices in the near term. Capacity prices are projected to increase in the 2030s as energy prices fall and gas prices continue to rise. The projected increase in capacity prices by 2045 is 3x - 5x higher than recent levels in nominal dollars. The combined effects would leave Batavia exposed to high energy and capacity costs.

All-Hour Average Northern IL Hub Electricity Prices



Batavia Capacity Prices

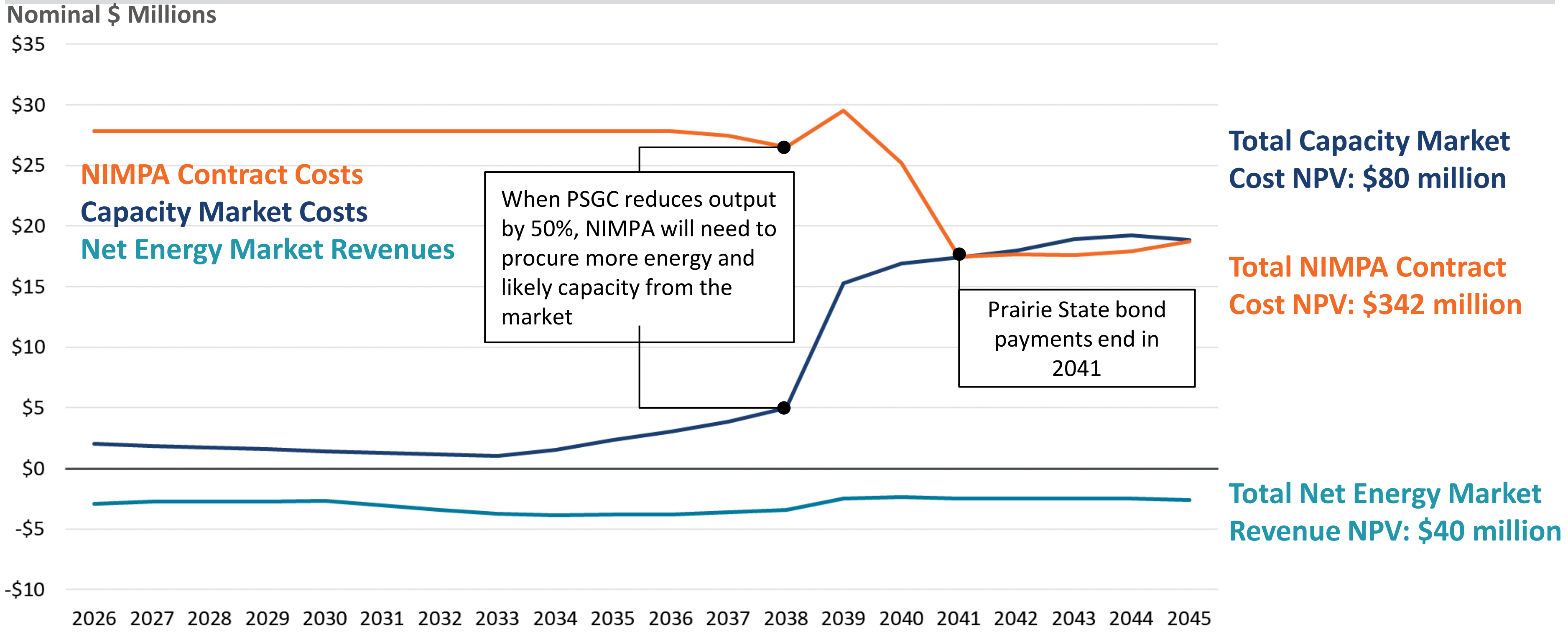


Notes: Rising gas prices and lower energy prices will reduce the profits gas fueled generators make in the energy market, leading to a higher Net Cost of New Entry (CONE). We assume Net CONE will define capacity prices that is the additional revenue needed from the capacity market for these generators to recover costs.

Key Observation 5: Batavia's Net Cost (Reference Case)

Based on our projections, Batavia's biggest cost risk will be from capacity market payments, which will increase as PJM capacity prices are expected to increase (see previous slide). The City's 55 MW NIMPA contract reduces its exposure to energy price risk.

Batavia Projected Energy and Capacity Procurement Costs (Revenues) 2026-2045, Reference Scenario



Notes: Capacity market costs reflect Batavia's capacity market payments for load net of 55 MW from the NIMPA contract through 2038 and 27.5 MW from the NIMPA contract from 2039-2045. NIMPA contract costs reflect Prairie State bond payments and passed-through O&M expense. Net energy market revenue is the difference between the cost of energy purchased to meet Batavia's demand and revenues from sales of the 55 MW of energy received under the NIMPA contract.

Key Observation 6: Supply-Side Resource Options

Procuring additional generation or storage resources or investing in demand reduction programs could reduce Batavia's exposure to high market prices, particularly for capacity. We evaluated resources that could be suitable given Batavia's location, size, customer makeup, and other parameters.

Supply-Side Resource Selections for Detailed Consideration

Technology	Use Case	Key Considerations
4-Hour Battery	Capacity and energy hedge	Batteries reduce Batavia's exposure to volatile energy market prices by discharging during peak hours, but charging costs reflect losses and may be volatile if charging from the grid.
Standalone Solar	Energy (and partial capacity) hedge	Non-emitting; zero marginal cost; but output is variable (wind has high capacity factor)
Standalone Wind		
Solar + 4-Hour Battery	Capacity and energy hedge	Can reduce exposure to high energy and capacity market prices by shifting renewable energy to peak periods
Natural Gas RECIP	Capacity and energy hedge	Flexible supply, relatively low upfront costs but GHG emitting; can be configured to burn clean fuels to enable continued capacity market participation post-2045 when Climate and Equitable Jobs Act (CEJA) regulations phase out natural gas-fired generation

Resource Portfolio Evaluation Factors

Evaluation Factor	Description	Batavia's Preference
1. Ownership Structure	Owned vs. Contracted	Flexible
2. Resource Location	In city/county/state/PJM/ outside of PJM	Prefer local
3. Resource Diversity	One versus multiple resources	Well-balanced, diversified portfolio
4. Hedging Policy	Max short and long positions allowed	No formal policy; prefer to not "play" in market
5. Time to Connect	Prioritize resources that can be built and connected quickly	N/A (NIMPA Contract still has 20+ years)
6. Timing	When to acquire resource	N/A (NIMPA Contract still has 20+ years)
7. Technology Maturity	Appetite for established vs. emerging technology	Prefer proven/reliable technology

Notes: Not all resource options considered in this IRP are shown above. Technologies that were screened out prior to detailed evaluation are discussed in Section 6 Supply-Side Options (page 64).

Key Observation 7a: Batavia's Net Cost Across Portfolios

A natural gas reciprocating engine (RECIP) deployed in in the late 2020s (as early as possible) may be the best option for re ducing Batavia's exposure to capacity market risk. This finding is robust across different assumptions about the availability of federal tax credits.

Total Present Value of Cost to Serve Batavia's Electricity Demand Under Six Resource Portfolios With Cost-Minimizing Online Dates, Reference Scenario

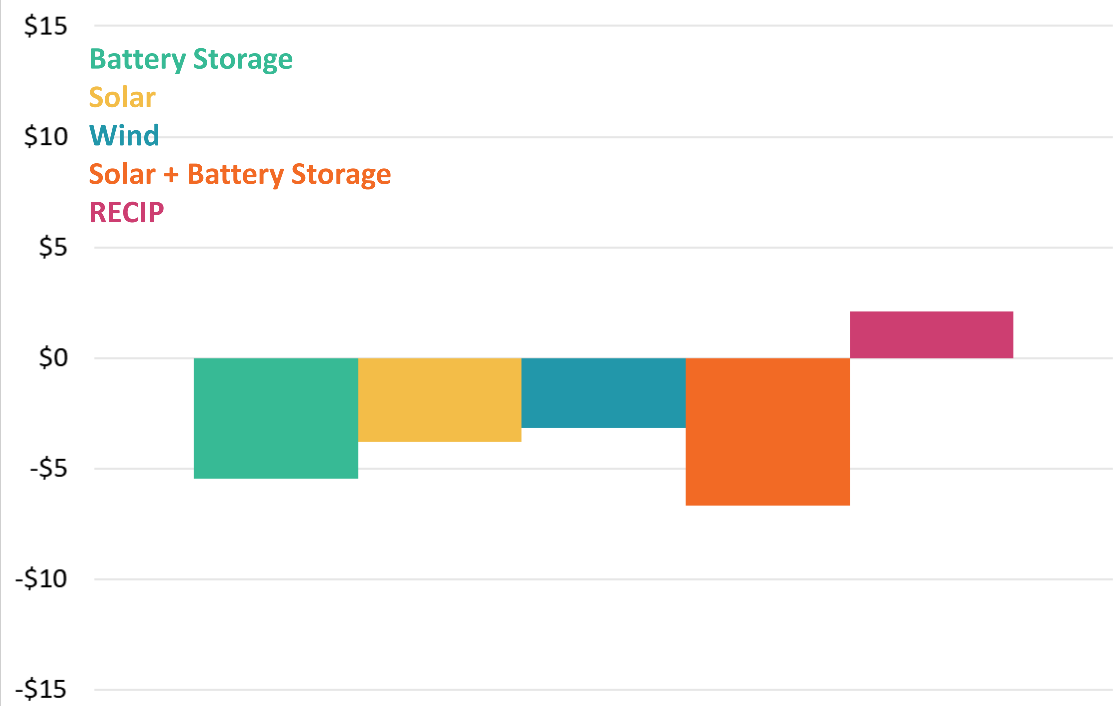
2025$ thousands		Portfolio 1: Status Quo	Portfolio 2: 10MW BESS	Portfolio 3: 10MW Solar	Portfolio 4: 10MW Wind	Portfolio 5: 10MW Solar, 7.8MW BESS	Portfolio 6: 10MW RECIP
Optimal Online Date			2042	2045	2045	2042	2035
Resource Costs							
Capital Costs	[1]	$0	$2,654	$416	$749	$3,620	$8,446
Fixed O&M Costs	[2]	$0	$886	$116	$239	$807	$4,967
Dispatch Costs	[3]	$0	$555	$0	$0	$433	$6,782
Tax Credits	[4]	$0	$0	$0	$0	$0	$0
Total Resource Costs	**[5] = SUM([1]:[4])**	**$0**	**$4,095**	**$532**	**$987**	**$4,859**	**$20,195**
Resource Revenues							
Gross Energy Market Revenues	[6]	$0	-$1,649	-$451	-$648	-$3,091	-$9,488
Capacity Market Revenues	[7]	$0	-$2,597	-$64	-$241	-$2,299	-$14,733
Total Resource Revenues	**[8] = [6] + [7]**	**$0**	**-$4,246**	**-$515**	**-$890**	**-$5,390**	**-$24,221**
Load Costs							
NIMPA Costs	[9]	$342,153	$342,153	$342,153	$342,153	$342,153	$342,153
Energy Market Costs	[10]	-$39,705	-$39,705	-$39,705	-$39,705	-$39,705	-$39,705
Capacity Market Costs	[11]	$80,177	$80,177	$80,177	$80,177	$80,177	$80,177
Total Load Costs Net of NIMPA Contract	**[12] = [9] + [10] + [11]**	**$382,626**	**$382,626**	**$382,626**	**$382,626**	**$382,626**	**$382,626**
Net Cost of Serving Load	**[13] = [5] + [8] + [12]**	**$382,626**	**$382,475**	**$382,643**	**$382,724**	**$382,095**	**$378,601**
Savings from Portfolio 1			**$151**	**-$17**	**-$98**	**$531**	**$4,025**
Percent Difference from Portfolio 1			**0.0%**	**0.0%**	**0.0%**	**0.1%**	**1.1%**

Key Observation 7b: Batavia’s Net Cost Across Scenarios

In light of recent tax credit policy developments, a natural gas RECIP deployed in the late 2020s (as early as possible, see slide 24) is the best option for reducing Batavia’s exposure to both energy and capacity market price risk. The **total** cost savings of each new resource option relative to Portfolio 1 (Status Quo) in Net Present Value (NPV) over 20-year study period are summarized below.

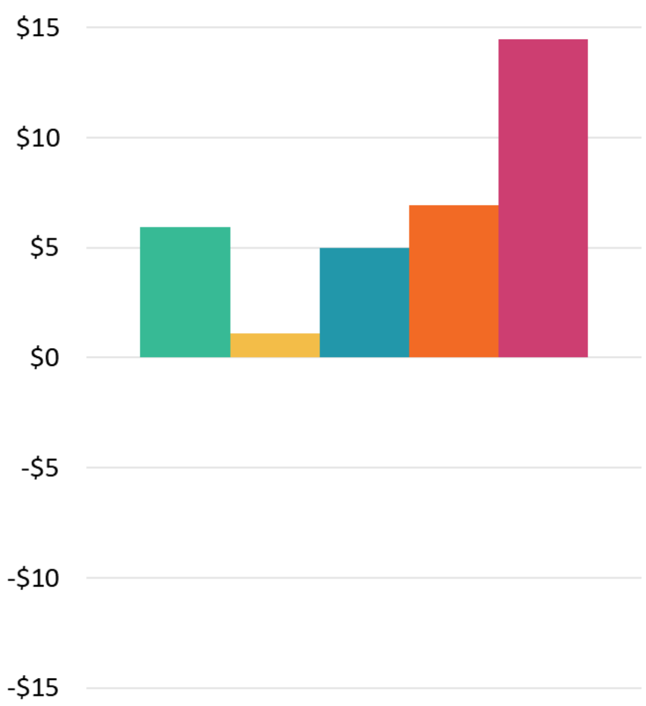
Reference Scenario Savings for a 2030 Resource Deployment

Total 2025$ Millions in Present Value



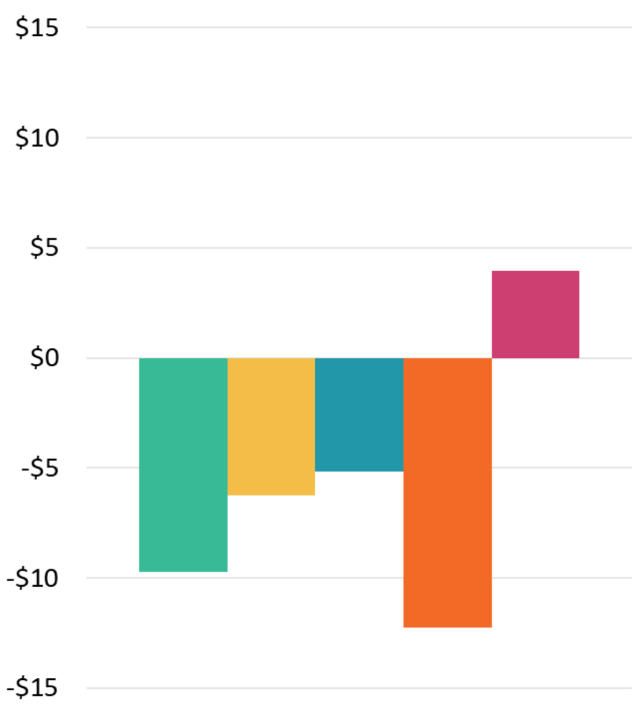
High Market Price Scenario

Total 2025$ Millions in Present Value



Low Market Price Scenario

Total 2025$ Millions in Present Value



Notes: Negative values indicate increased costs. High Market Price and Low Market Price results assume 2030 resource deployment dates.

Key Observation 8a: Demand-Side Resource Options

We recommend Batavia to explore smart thermostat, TOU rates, and EV managed charging programs to further help to reduce exposure to volatile market prices, especially as the potential participant base grows.

Summary of Demand Side Resource Options Modeled

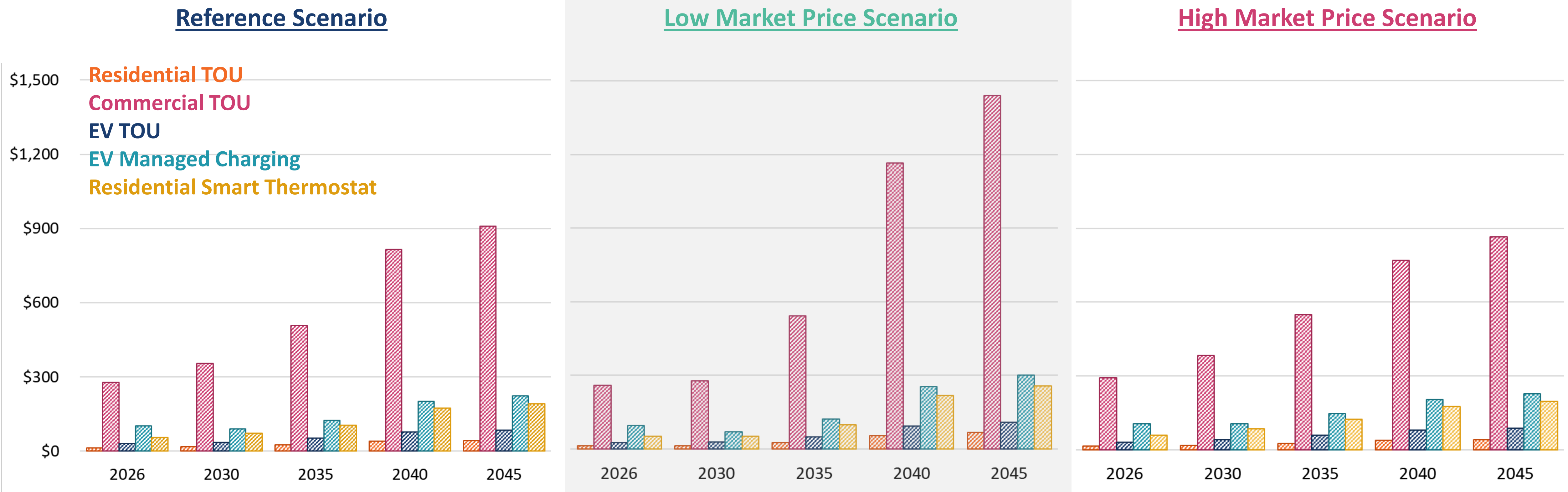
DSR Program	Description	Customer Segment	Primary Grid Impact	Modeled Benefit ($/Participant-Year, 2030)	Adoption Potential
TOU Pricing	Time-of-use electricity pricing	Residential	Load Shifting	$17	Moderate
		Commercial	Load Shifting	$354	High
EV TOU Pricing	Time-of-use specific to EV charging	EV Customer	Load Shifting	$36	Low (current), growing
EV Managed Charging	Utility-optimized EV charging schedules	EV Customer	Load Shifting	$90	Low (current), growing
Smart Thermostat	Programmable/automated thermostat for Summer cooling	Residential	Load Reduction	$73	High

Notes: TOU and Smart Thermostat programs are modeled to target the summer months, when Batavia's system peaks.

Key Observation 8b: Demand-Side Resource Benefits

Demand-side programs that Batavia should prioritize will depend on specific program costs, including upfront investments into necessary infrastructure (e.g., IT hardware and software), customer incentives, and labor costs; customer interests; and the City's organizational capacity.

Benefit Modeling Results ($/Participant-Yr)



Key Observation 9a: Legislative Requirements on IRP

Our analysis that began in January 2025 aimed to satisfy the requirements set forth in the Municipal and Cooperative Electric Utility Transparent Planning Act, enacted as part of the Clean and Reliable Grid Affordability Act (SB 25, Public Act 104-0458). These legislations require municipal electric utilities to develop, publicly post, and periodically update an Integrated Resource Plan (IRP). The IRP must evaluate long-term electric resource needs and outline near-term implementation actions, with consideration of cost, reliability, environmental impacts, resilience, and transparency. The table below summarizes the key legislative requirements and where they are addressed in this IRP.

Summary of Requirements and Corresponding IRP Sections

Key Requirement	Summary	Relevant IRP Section
Planning Horizon	Evaluate resource needs over a long-term planning horizon.	Section 4: Batavia Load Forecast
Load Forecast	Include a range of load forecast reflecting expected demand, electrification, distributed energy resources (DERs), and demand-side management (DSM) impacts.	Section 4: Batavia Load Forecast
Evaluation Criteria	Analyze options based on cost, reliability, environmental impact, and resilience.	Section 6: Supply-Side Option
Resources Considered	Evaluate supply-side options, demand-side programs, power purchases, and DERs.	Section 6: Supply Side Option and Section 7: Demand Side Option
5-Year Action Plan	Must include a detailed plan for the next 5 years, identifying specific steps the utility intends to take.	Section 8: Five-Year Action Plan
Transparency	Publish the IRP and supporting materials on the City's website in accordance with applicable accessibility requirements and provide access to underlying data and methodologies	Draft and updated report provided for public review

Key Observation 9b: Batavia Customer Preferences

A customer survey carried out in May 2025 indicated that Batavia's electric customers prioritize affordability and reliability over decarbonization when considering Batavia's electric portfolio. Written feedback emphasized the need to align energy policy with household financial realities.

- Survey results indicated that 73% of electric customers (both in absolute number of survey respondents and when survey responses were adjusted for City demographics) were not willing to pay more than a 10% premium on their electricity bills to support the City's decarbonization goals.
- When asked to allocate 100 points across priorities including energy affordability, reliability, decarbonization, and equity/innovation issues, Batavia customers allocated twice as many points to affordability and reliability (60 points) than to decarbonization and environmental goals (30 points).

Our analysis aimed to present several resource options with various cost and environmental tradeoffs. We screened out supply options that would increase Batavia's emissions intensity relative to relying on market purchases.

Batavia Customer Survey Results on Cost Sensitivity

To what extent would you be willing to pay a premium on your electricity bill to support a portfolio that improves the city's environmental impacts (e.g., lower carbon emissions, improved air quality)?	Percent of Data	Weighted Percent of Data
I am not willing to pay any more for environmental improvements.	37.7%	38.8%
I am willing to pay up to 5% premium on my bill.	19.4%	19.3%
I am willing to pay 5–10% premium on my bill.	16.1%	14.9%
I am willing to pay a 10-15% premium on my bill.	6.4%	5.5%
I am willing to pay more than a 15% premium on my bill for environmental benefits.	5.0%	3.7%
I'm not sure / need more information.	15.5%	17.8%

Notes: "Weighted Percent of Data" column adjusts raw survey results based on City demographics.

Key Observation 9c: Batavia Energy Policy

In September 2025, Batavia's City Council passed an energy policy directing the Batavia Municipal Electric Utility to "implement an energy portfolio, and associated infrastructure upgrades, to support the goal of reducing community-wide greenhouse gas emissions to 25% below 2019 levels by 2030 and achieve carbon neutrality by 2050."

- Given the City's purchased power contract with NIMPA, PSGC will generate the energy under the contract and the City is obligated to purchase it or default on the contract. Thus, no GHG reduction is possible by 2030.
- Batavia's energy policy does not discuss implementation timing or emissions reductions by sector (e.g., transportation, heating, electricity, etc.). For example, transportation electrification could increase electric sector emissions, while decreasing economy-wide emissions, usually at a lower cost than solely focusing on electric utility sector decarbonization.
- Without further details, developing a five-year plan (as required by Public Act 104-0458) to meet the City's 2030 policy goals is not realistic as of today.

Batavia's energy policy lays out the City's investment policies:

- "Energy efficiency and demand-side programs will be prioritized in the near term as both cost-effective first steps, and to support Greenest Region Compact implementation, before significant new capacity additions are made."
- "The Batavia Municipal Electric Utility will seek portfolio diversity, phased procurement, and contracts for large-scale resources."

Reflected in the draft IRP.

- "Local grid modernization and internal upgrades will be pursued aggressively to improve local reliability and reduce connection timelines for distributed and utility-scale resources."

To be addressed in resiliency study.

Outside of Batavia, recent changes in the political, market, and regulatory environment reduce the economic attractiveness ofcleaner resource options.

- Federal tax credits for renewable generation are facing accelerated phase-outs. Storage technology tax credits are likewise facing restrictions related to stringent component sourcing rules.

Key Observation 9d: Cost Premium of Cleaner Portfolios

This draft IRP aims to strike a balance between meeting Batavia's environmental goals and minimizing customer bill impacts (see footnote). The IRP aims to present several resource options with various cost and environmental tradeoffs.

- Portfolio 6 with a 10 MW RECIP would lower customer bills and overall emissions relative to Portfolio 1, which relies on market purchases.
- Choosing low or zero emissions technologies (Portfolios 2-5) over Portfolio 6 could increase Batavia customer costs by $3.5-4.1 million over 20-years in the Reference Scenario.

The Five-Year Action Plan recommends deploying demand-side resource programs to reduce Batavia's total electricity consumption (and thereby greenhouse gas emissions) and customer bills (through incentives and/or time-of-use pricing).

We plan to address updates, including to the five-year action plan, in the final IRP scheduled to be released in 2026.

Cost Premium of Low-GHG Emitting Portfolios Over Portfolio 6 (RECIP)

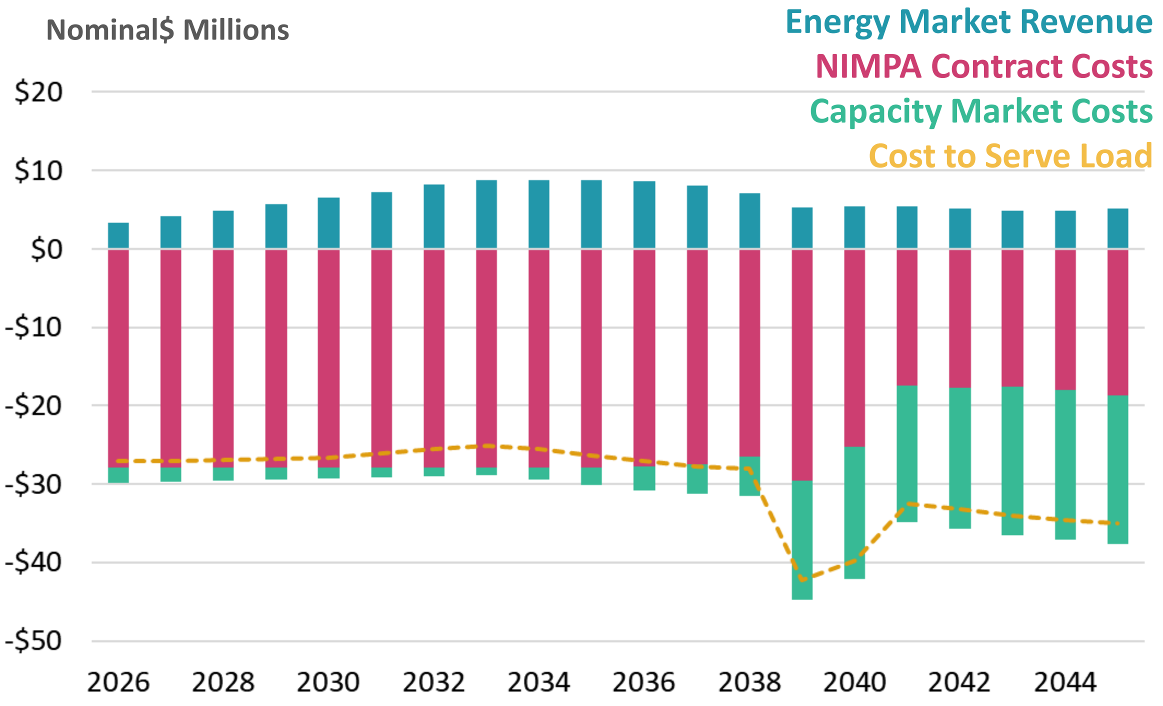
2025$ thousands		**Portfolio 6: 10MW RECIP**	**Portfolio 2: 10MW BESS**	**Portfolio 3: 10MW Solar**	**Portfolio 4: 10MW Wind**	**Portfolio 5: 10MW Solar, 7.8MW BESS**
Reference Scenario	Net Cost of Serving Load	$378,601	$382,475	$382,643	$382,724	$382,095
	Cost Premium Over RECIP		**+$3,874**	**+$4,042**	**+$4,123**	**+$3,494**
High Market Price Scenario	Net Cost of Serving Load	$352,493	$361,267	$365,329	$362,495	$359,101
	Cost Premium Over RECIP		**+$8,774**	**+$12,835**	**+$10,002**	**+$6,607**
Low Market Price Scenario	Net Cost of Serving Load	$435,085	$439,465	$439,237	$439,356	$439,486
	Cost Premium Over RECIP		**+$4,380**	**+$4,152**	**+$4,271**	**+$4,401**

Notes: Optimal online years from left to right: Reference Scenario: 2035, 2042, 2045, 2045, 2042; High Market Price Scenario: 2028, 2031, 2034, 2030, 2032; Low Market Price Scenario: 2028, 2045, 2045, 2045, 2045. The RECIP proposed in Portfolio 6 has lower emissions than the average PJM generation fleet. Relative to Portfolio 1, which relies on market purchases, all Portfolios are expected to reduce emissions associated with serving Batavia's electric load.

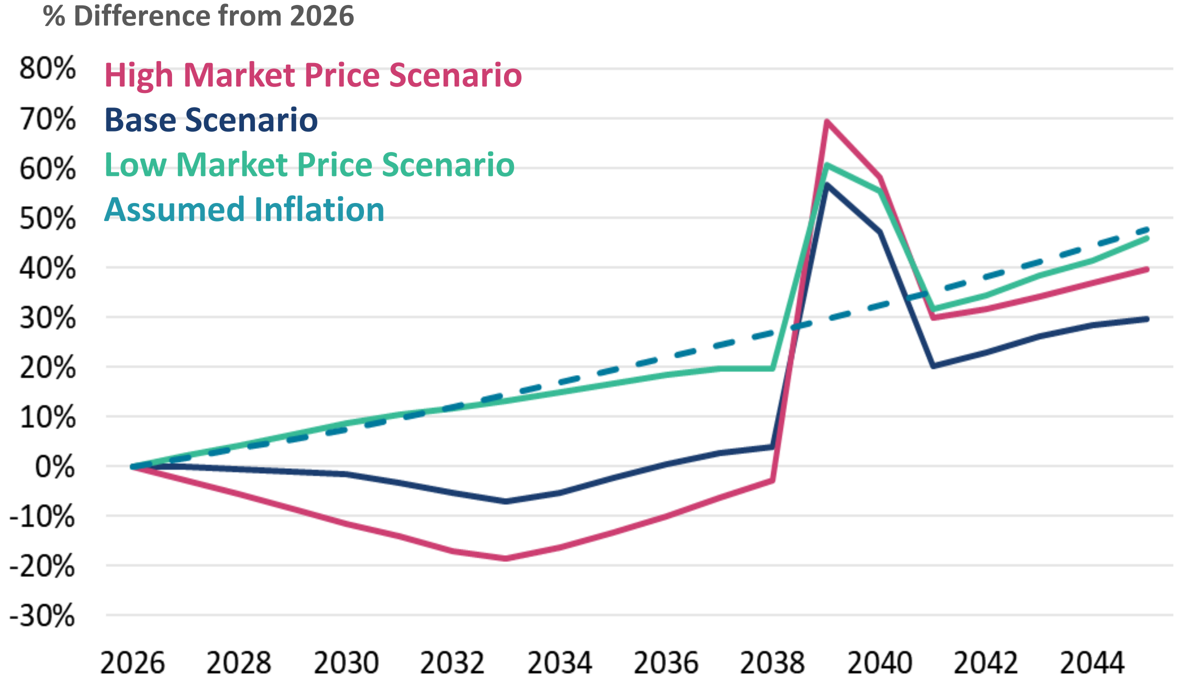
Key Observation 9e: Bills Expected to Grow Over Time

In the long run, customer bills will grow over time, regardless of portfolio or scenario. The cost-to-serve components show that increasing capacity market costs drive future bill growth, while Batavia benefits from net energy sales under its NIMPA contract in the 2030s before these benefits are gradually offset by rising costs.

Batavia Cost to Serve Over Time (Base Scenario)



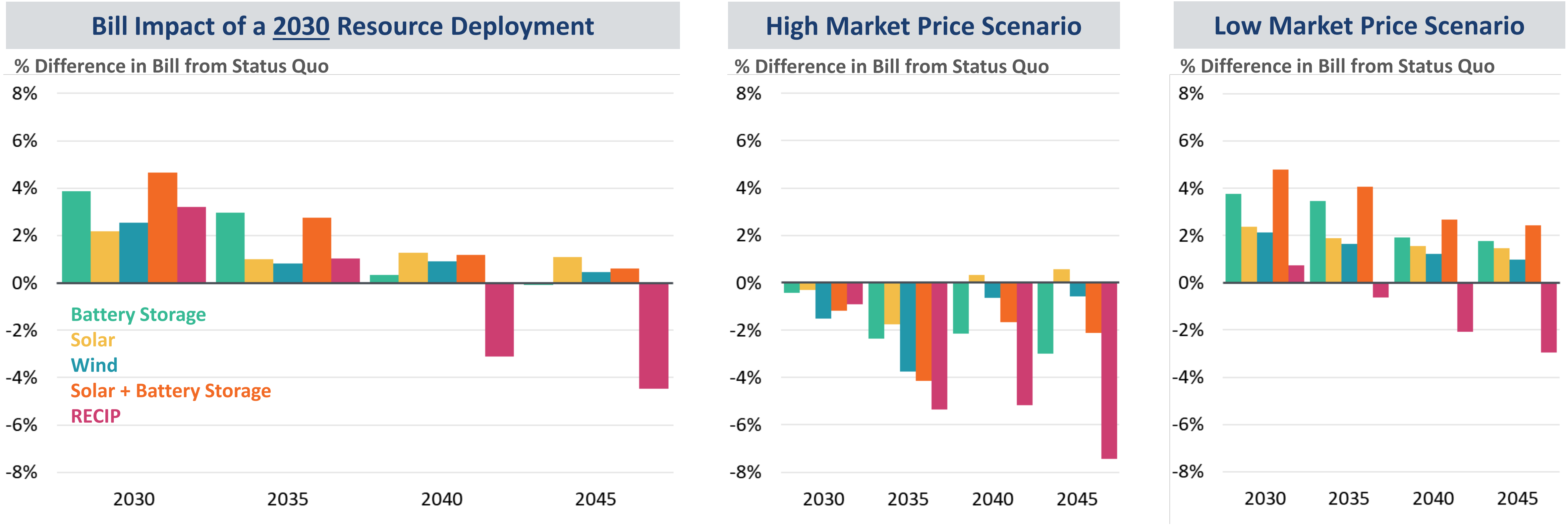
Average Bill Over Time (Status Quo)



Notes: Inflation forecast from EIA, 2025 Annual Energy Outlook, GDP Chain-Type Price Index. Bill increases after 2038 are primarily driven by rising PJM capacity prices. Lower financing costs associated with the NIMPA contract partially offset these increases. Figure on the left shows costs as negative values and partially offset by Energy Market Revenues (positive values).

Key Observation 9f: Bill Impacts Over Time from Cleaner Portfolios

While customer bills would initially increase after any resource is deployed, only the RECIP will reduce customer bills in la ter years relative to the status quo. Most cleaner portfolios will continue to increase cost to ratepayers once operational.



Notes: All percentages are relative to status quo. High Market Price and Low Market Price results assume 2030 resource deployment dates.

Key Observation 10: Five-Year Action Plan Timeline

We recommend that Batavia focus on building its capacity to respond to emerging market and policy conditions over the next five years.

	Year 1	Year 2	Year 3	Year 4	Year 5
Market/Policy Monitoring	Throughout this period, City should continue monitoring market and policy developments, including energy and capacity prices, resource costs, tax credit policy, environmental regulations, and programs, grants, loans, or tax benefits that are potentially available to help support resource procurement. Update economic analysis of different resource options as appropriate.				
System Upgrades	Evaluate hardware and software upgrades needed to support supply- and demand-side resources and incoming data center.	Initiate procurement of hardware and software upgrades enabling demand-side programs			Evaluate upgrading system information and control technologies to automate demand-side program calls through DERMS.
Supply-Side Resources	Issue RFIs for supply-side resources, focusing on RECIP procurement.	Initiate limited procurement of supply-side resources (e.g., 1-5 MW RECIP) to gain operational and market participation experience. Consider renewables or storage procurement, costs permitting.	Complete any necessary interconnection, testing, and initialization procedures for supply-side resource. Begin operating resource in PJM energy and capacity markets.		Evaluate procurement of additional supply-side resources based on experience with trial resource, market price evolution, policy developments, demand growth, and other factors.
Supply-Side / Demand-Side Resources	Work toward policy consensus on supply- and demand-side resources with City stakeholders.				
Demand-Side Resources	Initiate outreach campaign to recruit demand-side program participants, focusing on industrial customers.	Pilot demand-side programs with manual event calls, focusing on C&I customers.	Continue gaining experience with demand-side program participation. Continue outreach efforts to socialize programs and increase participation.		Evaluate adjustments to demand-side program portfolio based on load growth, customer participation, and program costs.
Demand-Side Resources		Review initial demand-side program data and survey participants to evaluate program effectiveness, participation patterns, and potential program improvements.			

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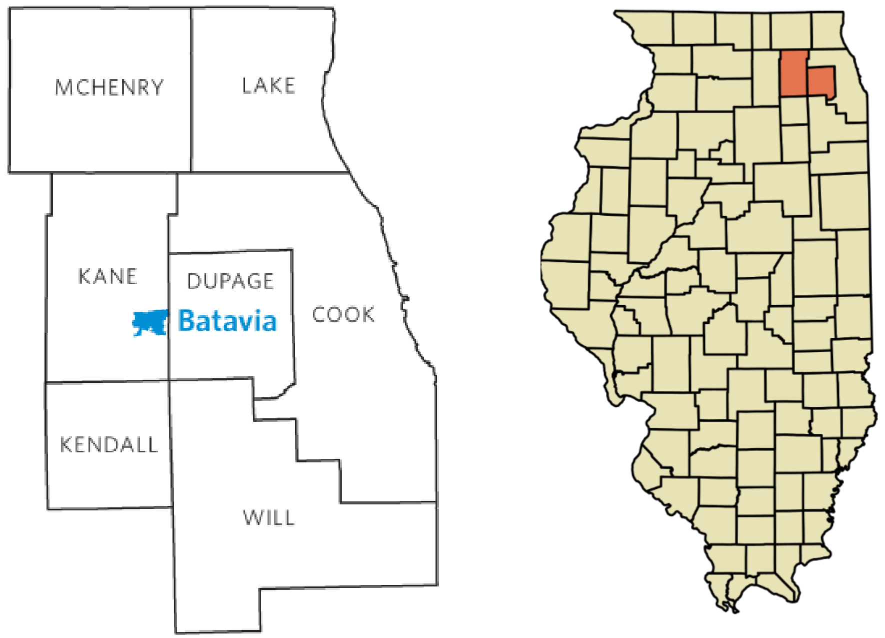
Introduction

Established in 1833, the City of Batavia is located in the greater Chicago area and has a population of roughly 26,000. The City's municipal electric utility serves 10,000 customers, across the residential, commercial, and industrial sectors*. In 2024, the peak electric demand was 87 MW (on August 5th), and the total annual energy consumption exceeded 414 GWh. The City owns and operates its own electric system, which interconnects to broader bulk power system operated by the PJM regional transmission organization (RTO). The City's service territory is 10 square miles.

The City meets electricity demand through a contract with the Northern Illinois Municipal Power Agency (NIMPA) and purchases in the PJM energy and capacity markets. Batavia's NIMPA contract entitles it to a 55 MW of firm, round-the-clock energy through NIMPA's partial ownership stake in the coal-fired Prairie State Generating Center (PSGC). This contract obligates Batavia to pay for PSGC bond payments and pass-through variable costs through 2041, regardless of the facility's operating status.

The City engaged Brattle to develop this integrated resource plan (IRP) in response to Illinois legislation (Public Act 104-0458) requiring all load serving entities in the state to conduct regular long-term resource planning efforts.

Location of Batavia in Kane and DuPage Counties, Illinois



Source: Wikipedia and Community Data Snapshot Municipality Series.

Notes: As a municipal utility, Batavia is not subject to FERC Form 1 filing requirements applicable to investor-owned utilities. Information presented in this IRP was compiled from City operational and financial records, available public power filings (including EIA 861), NIMPA information, and equivalent planning data sources. FERC Form 412 has not been filed in recent years due to administrative and budgetary constraints.

Resource Planning Process

This Integrated Resource Plan (IRP) is intended to help guide the City of Batavia in identifying actionable near -term strategies and informing longer-term planning efforts to ensure reliability, maximize energy affordability, and meet local and state energy policy requirements. The IRP includes a Reference scenario and two additional scenarios representing higher and lower load growth and resulting market prices.

To inform our selection of the preferred resource portfolio, we calculate the net present value of costs to serve Batavia's bad while pursuing a least-regrets plan (i.e., avoid the portfolios with high-cost risks) for each resource portfolio and scenario. Resource recommendations prioritize system reliability and cost in accordance with City's residents' preferences expressed in a recent stakeholder survey.

City engaged stakeholders in a March 2025 stakeholder meeting to set the direction for the IRP and did so again in September 2025 to solicit feedback on the IRP analytical approach, findings, and recommendations. The IRP process is the first of four studies and will inform subsequent infrastructure resiliency, cost of service, and rate design studies, the results of which will feed back to adjust IRP recommendations as needed. These ongoing studies are designed to prepare Batavia to provide reliable and cost-effective service in the light of an evolving power system.

Key Analytical Steps

1. Identify future energy and capacity needs

- Develop load forecast based on Batavia's existing customer base and changes to residential, commercial and industrial (C&I) customer characteristics
- Account for load drivers such as electric vehicle (EV) charging and adoption of distributed energy resources (DERs)

2. Compare costs of alternative resource portfolios

- Project PJM energy and capacity prices at Batavia's location
- Evaluate costs and potential upsides of new solar, wind, battery, and gas RECIP units
- Evaluate costs and benefits of demand-side resources

3. Scenario analysis to evaluate exposure to risks

- Identify key uncertainties (demand growth and timing, EV and DER adoption, state legislation and requirements, fuel prices, capacity prices)
- Develop scenarios with internally consistent set of sensitivities

IRP Legislative Requirements

Public Act 104-0458 requires municipal electric utilities to initiate an integrated resource planning process on or before January 1, 2027, and publish a preliminary Integrated Resource Plan (IRP) by January 1 of the following year. The IRP must evaluate long-term electric resource needs and outline near-term implementation plans, with a focus on cost, reliability, resilience, environmental impacts, and transparency. The table below summarizes the key legislative requirements and where they are addressed in this IRP.

Summary of Requirements and Corresponding IRP Sections		
Key Requirement	**Summary**	**Relevant IRP Section**
Planning Horizon	Evaluate resource needs over a long-term planning horizon.	Section 4: Batavia Load Forecast
Load Forecast	Include a range of load forecast reflecting expected demand, electrification, distributed energy resources (DERs), and demand-side management (DSM) impacts.	Section 4: Batavia Load Forecast
Evaluation Criteria	Analyze options based on cost, reliability, environmental impact, and resilience.	Section 6: Supply-Side Option
Resources Considered	Evaluate supply-side options, demand-side programs, power purchases, and DERs.	Section 6: Supply Side Option and Section 7: Demand Side Option
5-Year Action Plan	Must include a detailed plan for the next 5 years, identifying specific steps the utility intends to take.	Section 8: Five-Year Action Plan
Transparency	Publish the IRP and supporting materials on the City's website in accordance with applicable accessibility requirements and provide access to underlying data and methodologies	Draft and updated report provided for public review

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System Overview

The City of Batavia owns and operates its electric distribution system, which includes 6 substations, approximately 38 Miles of 15kV lines, 19 miles of 34kV overhead distribution lines, and 57 miles of 12kV and 9 miles of 34kV underground cables. In addition, Batavia's electric transmission system consists of approximately 10 miles of lines and a 138 kV bulk power supply line that delivers energy into the City's network*. Voltage is stepped down at City-owned substations to serve local distribution loads.

While Batavia maintains full ownership and operational control over its substations and distribution infrastructure, it does not own high-voltage transmission lines beyond the delivery point.[*1]

The City's electric utility serves residential, commercial, and industrial customers. The table below summarizes the customer composition and each customer class's contribution to energy use and peak demand in as of December 2024.[*2]

Characteristics of Different Customer Classes (2024)

Customer Class	Customer Count	Annual Energy Use (GWh)	Peak Demand (MW)
Residential	10,020	88	28
Commercial	1,369	131	19
Industrial	11	142	33
Market-Based	1	42	7

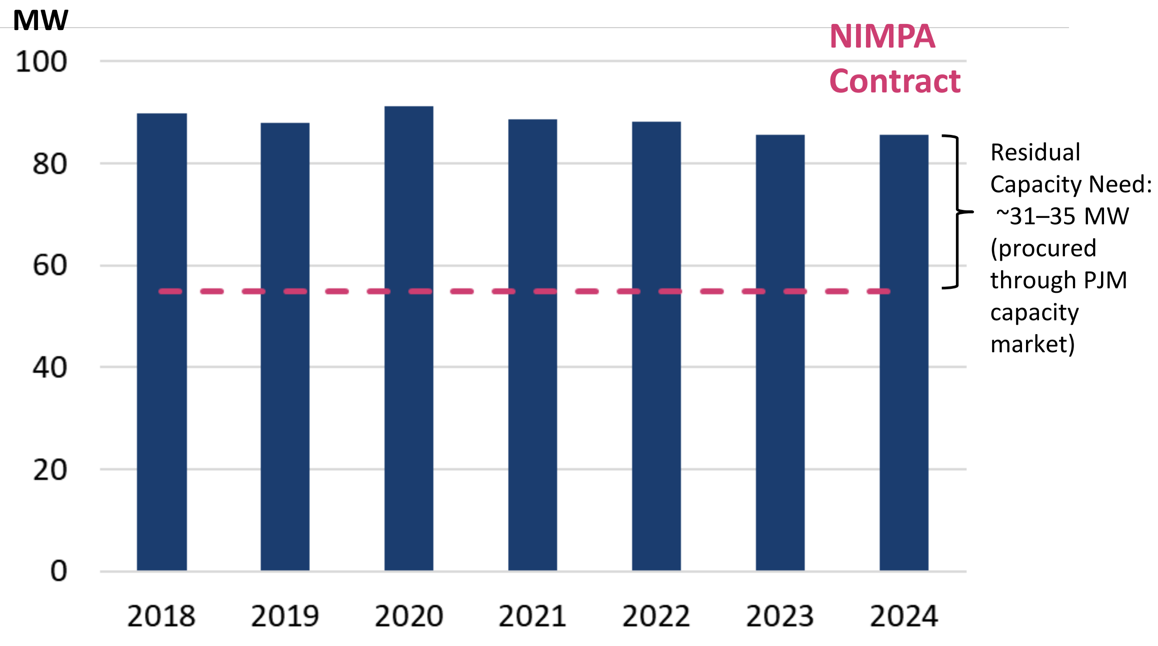
Notes:
*1: The facilities described are primarily distribution system assets associated with the utility's role as a distribution provider and load-serving entity, rather than bulk transmission paths. No formal contingency analysis was performed. Apart from the initial system buildout, no major transmission expansion projects (>$1 million) were identified.
*2: Based on sales data, which could differ from metered data.

Historical Load Growth

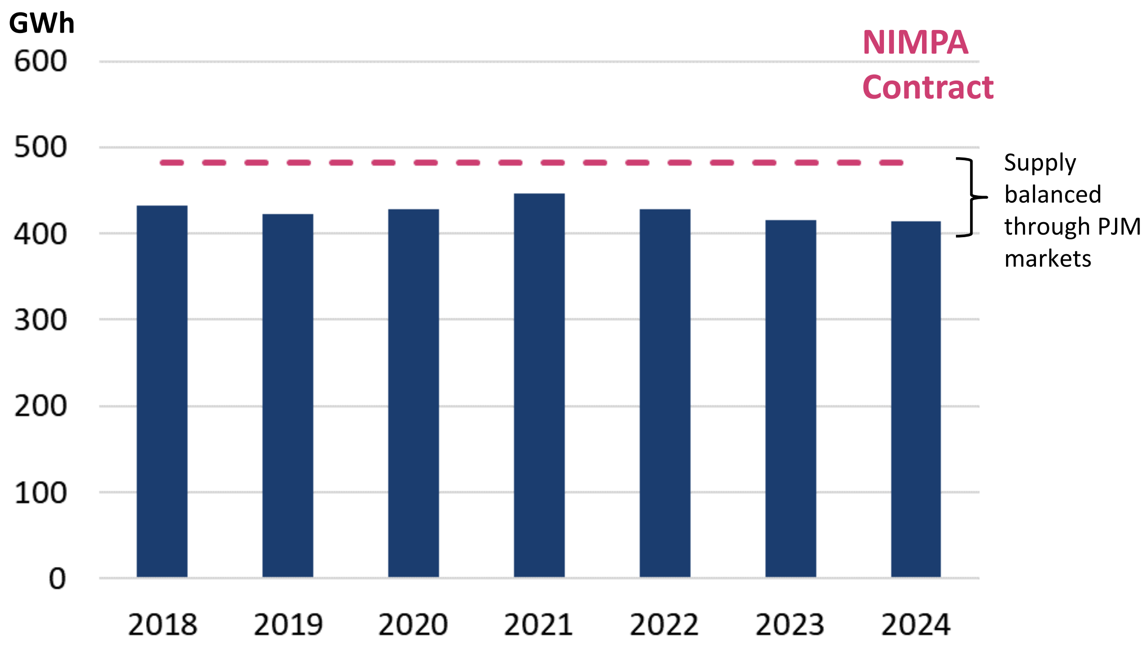
Batavia has experienced no load growth since 2018, and its current NIMPA supply contract provides more than enough supply for Batavia's annual energy needs. Batavia's 2024 peak load was 85.5 MW, compared to about 89.7 MW in 2018. Similarly, Batavia's annual energy consumption decreased from 432.9 GWh in 2018 to 414.5 GWh in 2024. For comparison, the NIMPA contract provides 55 MW (482 GWh) in supply.

For reference, Batavia's population grew by 2.6% between 2010 and 2023, or about 0.16% per year (according to CMAP).

Historical Annual Metered Peak Load



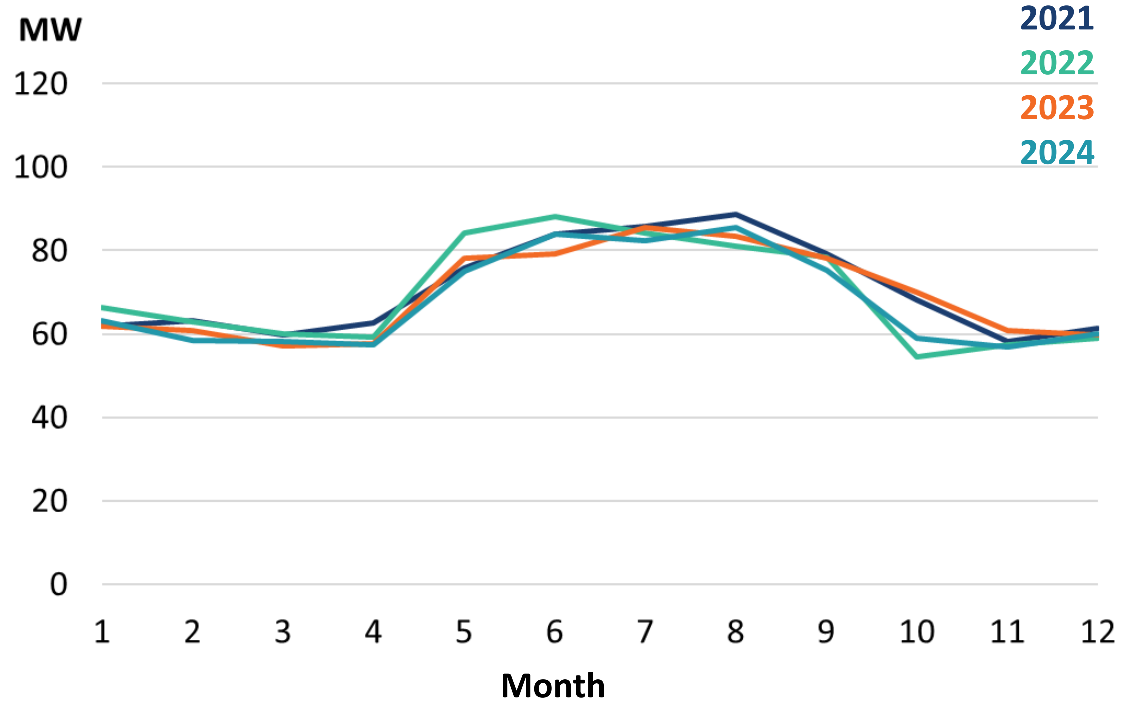
Historical Annual Metered Consumption



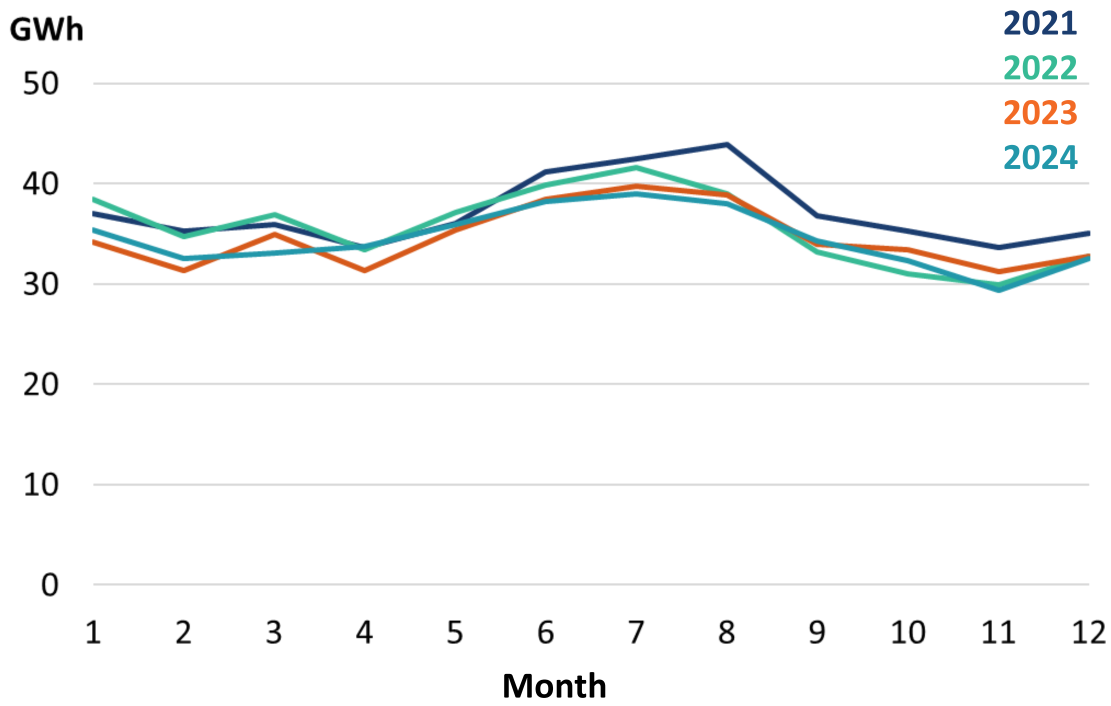
Seasonality of Batavia's Demand

Batavia's electric load exhibits a clear seasonal pattern, with both peak demand and energy consumption increasing during the summer months. There has been no sustained growth in system load in recent years. Between 2021 and 2024, monthly peak demand consistently ranged between approximately 80 and 95 MW, with peak months alternating between June, July, and August depending on the year. Total monthly energy consumption during this period remained within a relatively narrow range, with summer usage rising modestly before declining in the fall and winter.

Historical Peak Load by Month



Historical Consumption by Month



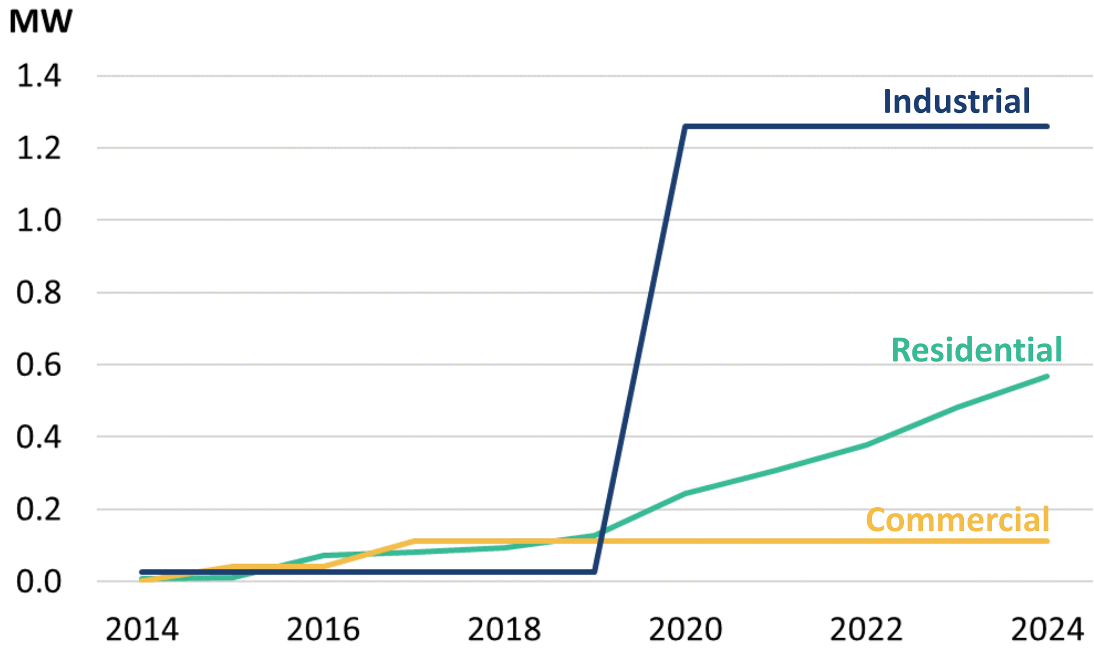
Source: Data provided by Batavia.

Batavia Historical Distributed Solar and EV Count

As of 2024, Batavia has 1.9 MW of distributed solar capacity, which represents just over 2% of the system net peak load. Residential distributed solar capacity has increased steadily since 2014, but commercial and industrial solar growth has been inconsistent, with flat installed solar capacity since 2017 and 2020, respectively. The majority (1.3 out of 1.9 total MW) of distributed solar belongs to industrial customers and specifically Suncast, who installed a 1.2 MW system in 2020.

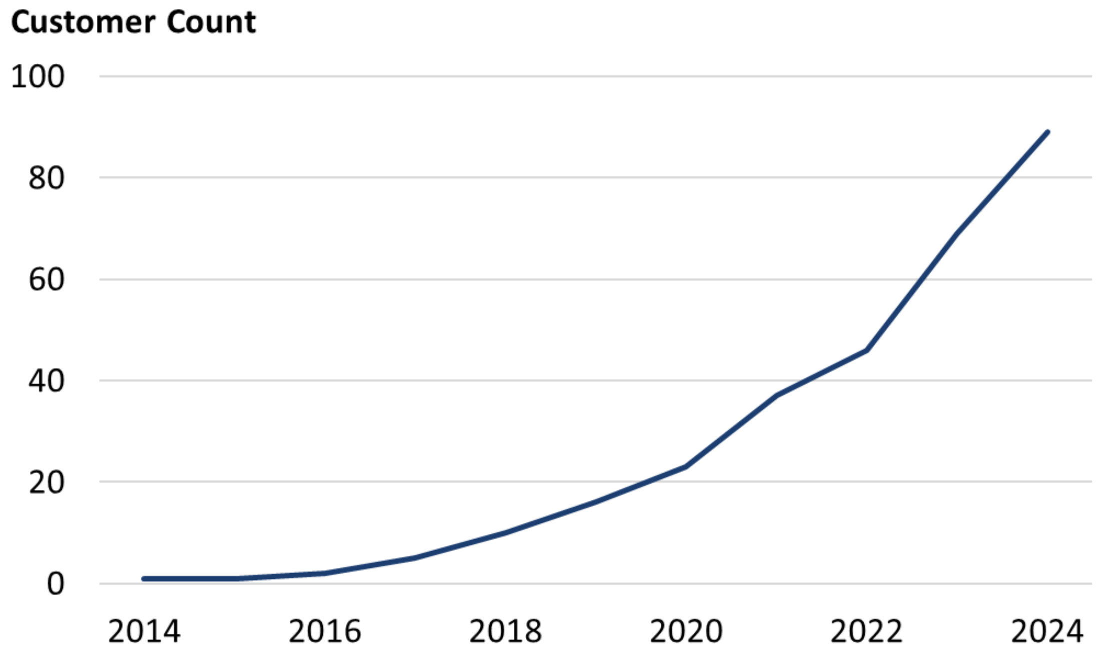
Batavia has few EVs but uptake has been steadily rising since 2014. It was estimated that as of 2024, Batavia had 89 EV customers, totaling about 1 MW of capacity.

Batavia Historical Distributed Solar Capacity



Source: Data provided by Batavia. Solar capacity reported in AC MW.

Batavia Historical EV Customer Count



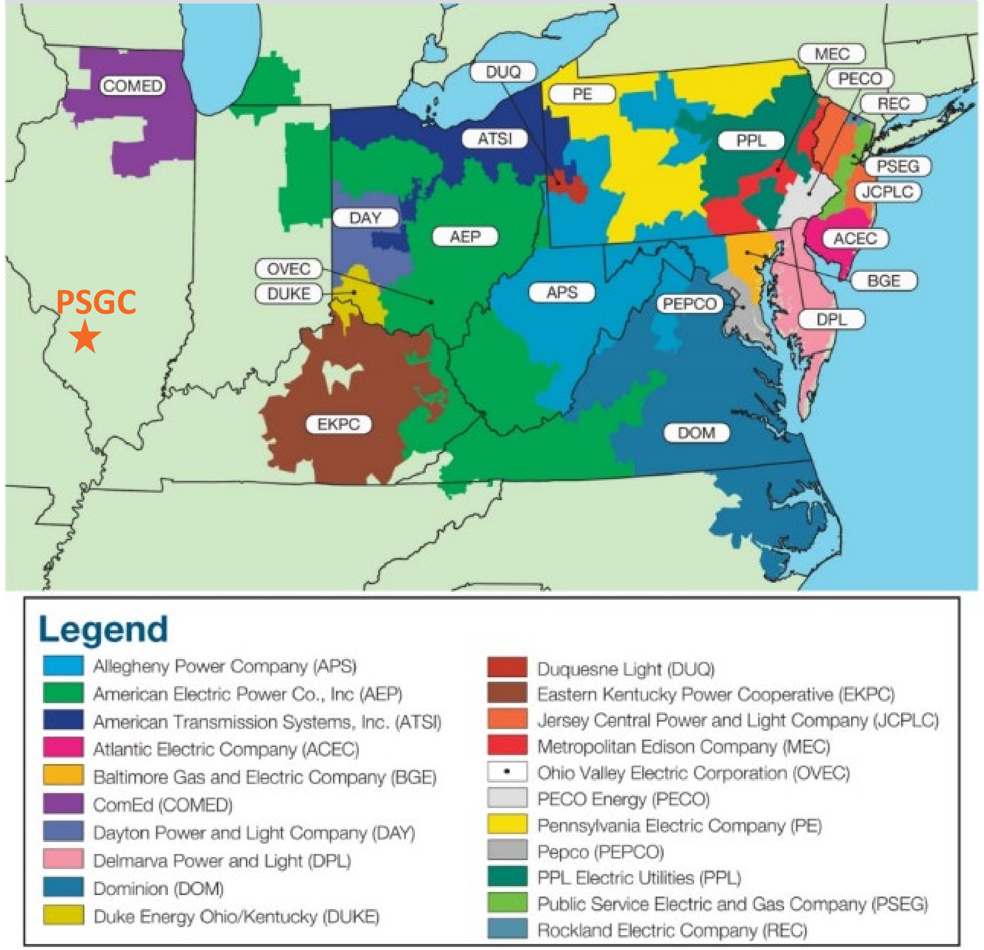
Note: The actual count of EVs as of June 2026 is 591.

Batavia and PJM Markets: 1/2

Batavia participates in the PJM wholesale electricity market, which covers 13 states from the Midwest to the Mid-Atlantic.

- Batavia relies on its NIMPA contract to meet the majority of the City's electricity demand (see next slide). During periods in which Batavia's electricity demand is less than its supply from the NIMPA contract, the City can sell that excess generation and earn a revenue.
- On the other hand, in periods when Batavia's electricity demand exceeds the amount of energy guaranteed under the NIMPA contract, the City has to purchase additional energy from the PJM market.
  - The price the City pays reflects both the cost of generating electricity and the cost of moving it from the generator to Batavia (i.e., Locational Marginal Price, or LMP).
  - The LMP (in $/MWh) at a given time is set by the cost of the most expensive generator operating at that time.

PJM Footprint



Source: Monitoring Analytics, 2024 Annual State of the Market Report for PJM, March 13, 2025.

Batavia and PJM Markets: 2/2

Batavia purchases **capacity** every year to cover its peak load and reserve margin[1].

- PJM's capacity market pays power plants a retainer for their ability to cover peak demand when it arises, even if they don't always generate.
- The capacity price (in $/MW-day or $/kW-year) is set by the most expensive resource to clear PJM's capacity market auction.

PJM has both system-wide and local reliability requirements. There are 27 Locational Deliverability Areas (LDAs) that can be separated and/or nested based on differences in generation, load, and import capability (i.e., transmission). Batavia is part of the ComEd LDA, which encompasses all the Illinois utilities in PJM.

- A "nested" LDA structure is used to reflect the relatively complex transmission topology and capability across the PJM system, in which successively smaller LDAs can procure capacity locally or from larger "parent" LDAs.
- Local capacity procurement requirements can be met through local supply and imports. Import capability is subject to available transmission capacity.
- When an LDA or parent LDA is resource-constrained, meaning that there is not enough supply within the LDA and further does not have the transmission capacity for additional imports from other LDAs, the price in that LDA can increase above the system price.
- Whether a sub-region is modeled as an LDA is determined by comparing the import limit of an LDA (also known as Capacity Emergency Transfer Limit, or CETL) to the amount of capacity that needs to be imported into the LDA to meet the reliability criterion (known as Capacity Emergency Transfer Objective, or CETO).
- A region is modeled as an LDA if CETL < 1.15 CETO, or had a locational price adder in any of three immediately preceding auctions.

Notes: 1: PJM has recently been discussing changes to the RPM. See Appendix C for further details.
PJM's Reliability Pricing Model ("RPM") incorporates reserve margin and LOLE-based reliability planning assumptions in establishing regional capacity procurement targets. RPM outcomes do not guarantee that the region clears above PJM reliability thresholds in every delivery year. The IRP analysis reflects Batavia's PJM reliability obligations by incorporating capacity market purchases for projected capacity shortfalls. Batavia does not currently conduct standalone capacity sales transactions outside of PJM and the NIMPA arrangement.

The NIMPA Contract : 1/3

Batavia is a member of NIMPA, which partially owns the Prairie State Generating Campus (PSGC) in Washington County, IL. NIMPA was created in 2004 to develop energy resources for Batavia, Geneva, and Rochelle in Illinois.

In 2007, NIMPA agreed to develop Prairie State Energy Campus (PSEC), which includes a two-unit 1,600 MW coal-fired generation plant (800 MW per unit) with an adjacent mine and coal reserves.

NIMPA is a partial owner of PSGC, and signs contracts with its members, including Batavia, to provide them with energy and capacity benefits.

In exchange for 55 MW of firm, 24/7 energy, Batavia's costs include:

- Payments on bonds used to finance PSGC's construction
- PSGC operating and maintenance costs, including fuel costs and administrative expenses
- PSGC's capacity market revenue is used to offset Batavia's energy purchase price.

Batavia's contract with NIMPA was approved on October 19, 2006 and will last for 50 years, or until NIMPA no longer holds ownership in PSGC.

Batavia's NIMPA Contract Costs (2021-2024)

		2021	2022	2023	2024
NIMPA Debt Service Costs	$MM	$14	$14	$14	$14
NIMPA Non-Debt Costs	$MM	$11	$14	$17	$13
Total NIMPA Contract Cost	**$MM**	**$26**	**$28**	**$32**	**$28**
NIMPA Contracted Energy	MWh	481,800	481,800	481,800	483,120
NIMPA Contract Costs per MWh	**$/MWh**	**$53.72**	**$58.75**	**$65.86**	**$57.67**

Source: Provided by the City of Batavia. NIMPA Contracted Energy = 55 MW x 8760 h/year (8784 in leap years). Table excludes Prairie State capacity revenues.

Due to CEJA regulations, PSEC is planned to reduce output by 50% at the end of 2038. After that, the NIMPA contract grants Batavia the right to replacement power purchased from the market at the market rate.

The NIMPA Contract : 2/3

Prairie State Energy Campus ("PSEC") is a two-unit coal-fired generation facility located in Washington County, Illinois and jointly owned by multiple public power agencies, including Northern Illinois Municipal Power Agency ("NIMPA" or the "Agency").

PSEC has an approximate nameplate capacity of 1,582 MW, with NIMPA holding an ownership interest of approximately 7.6%. Batavia does not own PSEC but receives rights to approximately 55 MW of firm energy and capacity benefits through its long-term NIMPA power purchase contract.

PSEC Unit 1 achieved commercial operation in June 2012 and Unit 2 achieved commercial operation in November 2012. Under CEJA, Prairie State is subject to emissions reduction requirements, including a targeted 45% reduction in emissions by 2038. The long-term compliance pathway, future operating configuration, and retirement timing of the units remain subject to evaluation by the plant owners and NIMPA.

PSEC remains an important component of Batavia's long-term resource position, providing access to dispatchable energy and capacity while also exposing the City to risks associated with fuel costs, operational performance, environmental compliance requirements, and long-term debt recovery obligations associated with the facility.

Prairie State Energy Campus Overview

Category	Summary
Ownership and Structure	Jointly owned by multiple public power agencies; NIMPA ~7.6% (120MW)
Commercial Operation (COD)	Unit 1: June 2012; Unit 2: November 2012
Useful Life & Retirement	Under CEJA, subject to a 45% emissions reduction target by 2038; future operations remain under evaluation
Capacity (Nameplate UCAP)	~1,582 MW
Annual Generation (GWh)	~12,500 GWh (2023); Batavia ~482 GWh/year contracted
Operational Performance	Capacity factor: **87.3%**; Availability: **89.3%**; Forced outage: **5.6%**

Notes: PSEC generated approximately 12,500 GWh of electricity in 2023 based on publicly available operational reporting. Batavia's contracted entitlement is approximately 482 GWh annually.
Publicly available accredited capacity (UCAP), maximum output ratings, and facility depreciation schedules were not separately identified.

The NIMPA Contract : 3/3

The City of Batavia does not own any generating facilities. Batavia receives power from a generating facility through a Power Sales Agreement ("PSA") with NIMPA (the "Agency"). The PSA requires Batavia to pay its respective share of all costs of the Prairie State Project to the Agency, including debt service, whether the Project is operating or operable or its output is suspended, interrupted, interfered with, reduced or curtailed or terminated in whole or in part. Such payments are not subject to any reduction, whether by offset, counterclaim, recoupment or otherwise, and are not conditioned upon the performance or nonperformance of the Agency or any other person under the Power Sales Agreement or any other agreement for any cause whatsoever.

The NIMPA contract was approved in 2006 and extends for 50 years, or until NIMPA no longer maintains ownership interests in PSEC. Because the contract is long-term and tied to NIMPA's shared ownership and debt recovery obligations associated with PSEC, early termination of the contract is not expected to be economically feasible. Accordingly, this IRP primarily evaluates incremental resources and market purchases that complement Batavia's existing NIMPA contract.

Under CEJA-related emissions reduction requirements, Batavia's future replacement power needs may be addressed through market purchases and/or incremental resource additions evaluated in this IRP.

Batavia/NIMPA Contract & Obligations

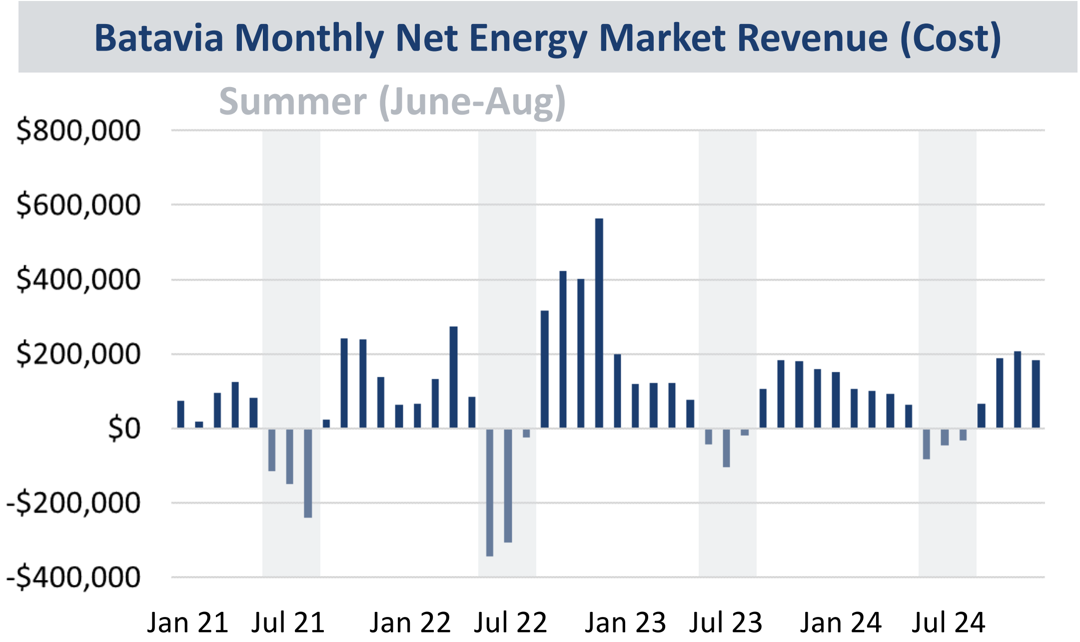
Category	Summary
Ownership Position	No Batavia-owned generation assets; ~55 MW power purchase via NIMPA (48.83%)
PPA Terms	Approved 2006 for 50-year term
Capacity Obligation (PJM)	NIMPA purchase offsets a portion of Batavia's PJM capacity obligation
Cost Responsibilities	Allocated share of PSEC debt service and project costs, including fuel, O&M, and administrative expenses
Replacement Feasibility	Long-term binding obligation; IRP evaluates incremental resources and market purchases

Notes: Batavia does not currently conduct standalone capacity sales transactions outside of the NIMPA arrangement and participation in PJM markets.
Capital expenditures (defined broadly as "Costs of Acquisition and Construction") are treated as part of the Project's overall cost structure. Capital costs are socialized to the city and the other Project participants as part of "Total Costs" (including operations, maintenance, capital additions, debt service, and related financing) and recovered through ongoing payments to the Agency. Capital contributions are made monthly to advance fund future capital costs as part of Total Costs. Capital costs made by Prairie State are paid by the Agency through Project participants (including the city) paying their share of those costs through monthly payments to the Agency. If debt is required to fund capital costs, the debt would be issued by the Agency and billed to Project participants (including the city) as part of the Total Costs of the Project. No capital expenditures in excess of $1,000,000 at existing generation facilities is expected.

Batavia's Exposure to PJM Energy and Capacity Markets

While the NIMPA contract provides energy and capacity services for Batavia to serve the City's customers, the mismatch in PSGC's generation profile and Batavia's system demand profile leaves Batavia exposed to volatile prices in the PJM energy and capacity markets. Historically, Batavia's electricity demand has exceeded the 55 MW supply provided by the NIMPA contract in hours and months when electricity prices tend to be high (e.g., summer months). To meet the shortfall, Batavia relies on market purchase and incurs a net energy cost.

Since 2018, the *difference* in Batavia's peak load and the 55 MW capacity from the NIMPA contract ranged between 31-35 MW. To cover capacity shortfall (including capacity reserve margins) , Batavia acquires additional capacity from the PJM market. Therefore, any increase in PJM capacity price in the future will magnify Batavia's exposure to the capacity market.



Sources and notes: Reflects energy market purchases and sales net of 55 MW NIMPA contract (in nom. dollars). Calculated using PJM Day-Ahead hourly LMPs at Batavia node from Energy Ventyx, Velocity Suite and Batavia hourly consumption data.

Planning Environment

Several factors will impact Batavia's ability to provide reliable and affordable electric service for the City's customers.

- **Load growth.** Accelerating electrical load due to data center deployment, electrification, and organic growth of the economy increase market prices for capacity and energy, potentially increasing the cost of Batavia's market procurements. Batavia is expecting to interconnect a new 50 MW data center load*, which can strain the City's infrastructure or increase customer costs if not managed through planning and rate design.
- **Increasing natural gas prices.** Natural gas-fired generation serves much of the US electrical demand. Increasing demand for US exports of liquefied natural gas (LNG) and accelerating load growth can increase the demand for natural gas, pushing its price up. Additionally, depletion of the lowest-cost natural gas wells and geopolitical tensions with natural gas-exporting nations such as Russia can contribute to rising natural gas prices. These factors create cost risk for Batavia's market purchases of energy from PJM or generation from gas-fired resources.
- **PJM market volatility.** Recent delays in PJM's capacity market auctions have resulted in substantial capacity price jumps, increasing the cost of providing reliable electricity service for Batavia's customers.
- **Supply chain tightness.** Global supply chains for generation technologies, components, and raw materials have increased the costs and reduced the availability of generating resources. These conditions may increase PJM capacity prices and the cost of Batavia's supply-side resource procurements.
- **Federal policies.** Shifting tax credit availability for renewable resources can reduce the economic attractiveness of new resource options Batavia can use to hedge against energy and capacity market price volatility. Further, evolving tariffs and other import duties act to increase the cost of generating resource procurements.
- **State policies.** The Climate and Equitable Jobs Act (CEJA) sets ambitious decarbonization and fossil fuel phase-out requirements for Illinois utilities. These policies can affect the cost of Batavia's market purchases, its NIMPA generation contract, and the resources Batavia can use to hedge against market price risk. Illinois' relatively progressive climate policies can be at odds with federal policies, reducing Batavia's compliance options and increasing its costs to serve customers.

This resource plan considers how these factors could evolve over time and the steps Batavia can take to minimize its cost and reliability risk.

Note: *The proposed data center is expected to procure power through the PJM wholesale market and is not assumed to be served by Batavia's existing power supply resources.

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Overview of Load Forecast Development

A central component of the IRP, load forecast provides a projection of Batavia's future energy and capacity needs*. Our load forecast provides hourly estimates of Batavia's load over the time period from the present to 2045.

How Batavia's system load changes over time will determine the level that the City will be exposed to energy and capacity market price volatility. This will in turn influence the potential need for resource additions to mitigate such volatility while meeting expected load changes.

Changes in Batavia's total system load will depend on changes to the City's "native load" as well as modifiers such as distributed solar capacity, electric vehicle (EV) charging load, end-use electrification, and industrial load.

- "Native load" refers to Batavia's gross load, which includes changes in electricity demand due to population changes or economic activity. It excludes EV charging load and load reductions due to distributed solar generation.

In this study, we provide separate forecasts for gross load, or the total electricity demand on the system, and net load, defined as the gross load less the contributions by non-dispatchable resources (e.g., renewable resources) and behind-the-meter (BTM) distributed energy resources. In formula:

- Gross load = Native load + EV charging load + Incremental end-use electrification + Incremental industrial load
- Net load = Native load + EV charging load + Incremental end-use electrification + Incremental industrial load – Distributed solar contributions to load

Each of the variables on the right side of the equation (e.g., native load, EV charging load, etc.) are referred to as individual forecast "subcases"

We developed an hourly load forecast to assess overall energy and capacity needs and evaluate intraday variability in load. This hourly forecast informs the design of the resource portfolio by identifying the operational capabilities needed to serve this load, such as ramping capabilities, flexibility, and compatibility with intermittent generation patterns.

Notes: This IRP represents Batavia's first formal long-term load forecasting and integrated resource planning effort. Accordingly, no prior IRP load forecasts are available for comparison against realized system load.

Key Load Contributors

The table below summarizes the methods used to develop the individual subcases of the final hourly load forecast.

Forecast Subcase	Notes
Native Load	Native load is projected to remain flat in future years, based on expected load growth in neighboring jurisdictions, including ComEd and Ameren Illinois.
EV charging load	Forecast is based on growth in the number of EVs expected in the neighboring ComEd jurisdiction. We use EV charging profiles sourced from NREL data to forecast hourly EV contributions to system load.
Incremental end-use electrification	Forecast is based on survey of current Batavia customers, who indicated no expectations of significant end-use electrification (outside of what is captured in our analysis of EV charging load).
Incremental industrial load	Forecast is based on survey of current and potential Batavia customers, who indicated no significant load growth in the near term. The new 50-MW data center load is not included in this load forecast because it is under development at the time of this analysis and is anticipated to be supplied exclusively from wholesale market purchases. We will evaluate the impact of this load in the final version of the IRP.
Distributed solar contributions to load	Forecast is based on expected growth of distributed solar in the neighboring ComEd jurisdiction. In addition, we assume the near-term addition of distributed solar, in line with what is currently planned by Batavia’s industrial customers. We use solar generation profiles from NREL PVWatts to forecast solar generation at the hourly level.

Load Forecast Cases and Subcases used in Build-Up of Cases

In addition to the **Base** load forecast (our base case expectations of future load patterns), we developed separate **High load** and **Low load** cases to test the robustness of the various resource portfolios. Alternative load cases ensure that the preferred resource portfolio is robust to load growth that differs significantly from our expectations, and not exposing Batavia customers to extreme high costs and reliability risks.

Load forecast cases are composed of separate individual forecast subcases of Native Load, Distributed Solar Contributions to Load, and Electric Vehicle Charging Load. Based on Batavia's survey of current customers, incremental end-use electrification and industrial load growth are assumed to have negligible impacts on the final load forecasts. As a result, these subcases are excluded from the development of final load cases.

To construct the **High** and **Low** load forecast cases, we first develop high and low estimates for Native Load, Distributed Solar Contributions to Load, and EV Charging Load. We then combine these estimates in the configurations shown at right to assemble the full set of load forecast cases.

- The **High Solar** (i.e., high capacity of distributed solar) subcase feeds into the **Low Load** case, because high installed solar capacity contributes to a lower net peak, all else equal (vice versa for the **Low Solar** subcase, which feeds into the **High Load** case).
- Because EVs increase the overall electricity demand, the **High EV** (i.e., high volume of EV load) subcase feeds into the **High Load** case (and vice versa for the **Low EV** subcase).

Load Forecast Cases and Subcases

Load Forecast Cases	Individual Forecast Subcases
Base	Base Native Load, Base Solar, Base EV
High	High Native Load, Low Solar, High EV
Low	Low Native Load, High Solar, Low EV

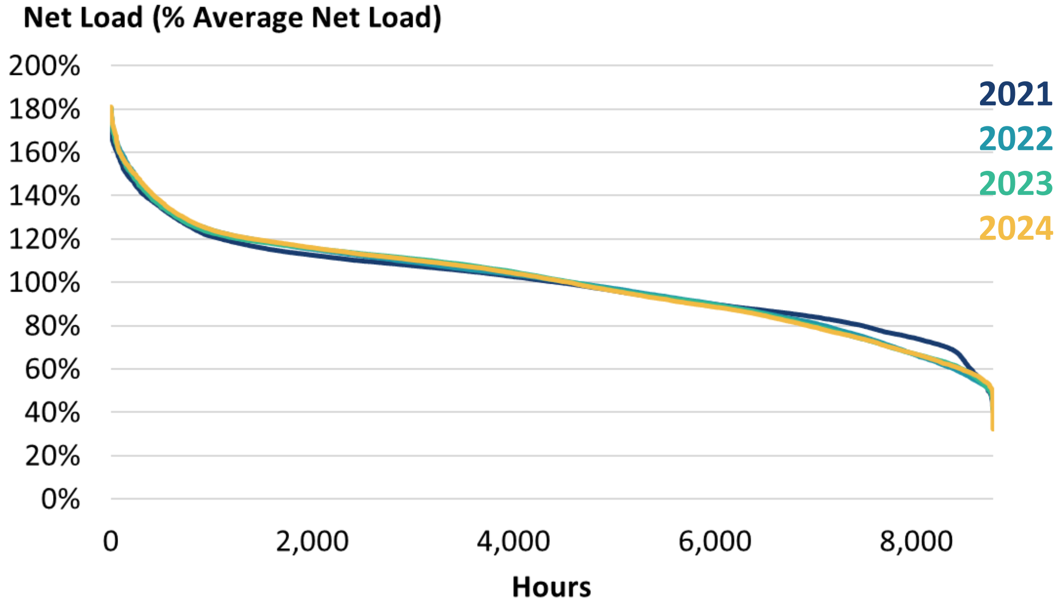
2024 as the Base Year

We developed annual load forecasts using 2024 as the base year. We selected 2024 because it offers the most up-to-date, full-year dataset when the initial analysis was completed in mid 2025. This selection means that the future years' load is based on 2024 load profiles and renewable generation profiles are based on 2024 weather data (to align with prices).

To examine the robustness of our decision to use 2024 as the study year, we analyzed 2021-2024 net load profiles and day-ahead (DA) locational marginal prices (LMPs) at the Batavia pricing node. In general, net load and Day-Ahead LMPs did not vary significantly between the years of 2021 and 2024.

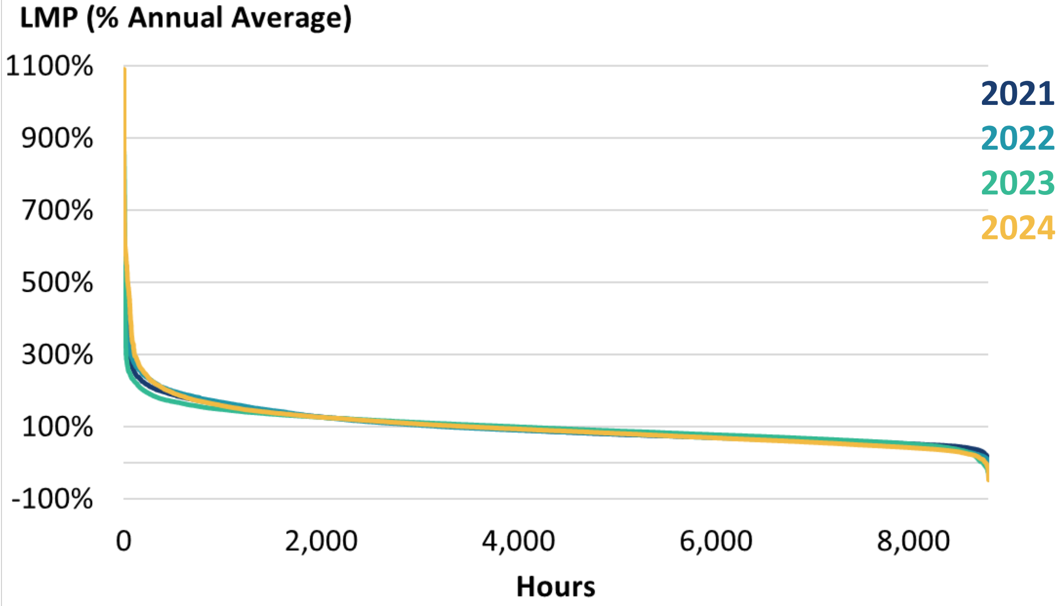
Selection of a representative study year prevents distortions in the future load shape and our subsequent calculations of the cost to serve system load.

Normalized Batavia Net Load Duration Curve



Source: Data provided by Batavia. Increase in 2021 load in hours 6,500 and beyond is due to SunCast's third work shift. Net load expressed as % of avg. net load by year.

Normalized Batavia Node Day-Ahead LMP Duration Curve



Source: Day-Ahead LMPs at Batavia node from Energy Ventyx, Velocity Suite. LMPs expressed as % of avg. LMP by year.

Native Gross Load Subcases

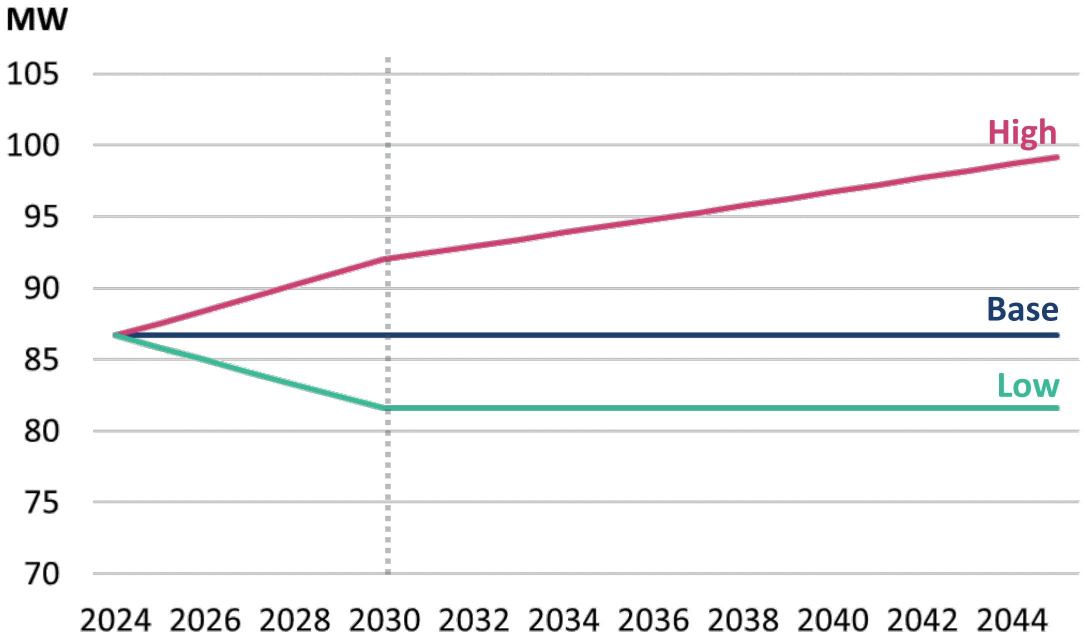
Our forecast of flat load growth in the **Base Native Load** subcase is based on historical and forecasted load in neighboring jurisdictions such as ComEd and Ameren Illinois, who like Batavia have experienced largely flat load in recent years. At the time of the analysis, these jurisdictions do not project significant load growth, outside of planned new data centers and manufacturing load.

Our **High** and **Low** Native Load subcases project significant annual near-term load growth and decline (respectively) before 2030, followed by more moderate changes in load thereafter.

We reconstituted the 2024 native gross load (the starting point for these load forecasts) by adding back the estimated generation from distributed solar and removing the impacts of EV charging load, which is forecast separately.

Load Subcase	Description
High Native Load	1% annual growth until 2030, then growth rate moderates to 0.5% per year until 2045
Base Native Load	Gross load is held at current levels until 2045
Low Native Load	Gross load decreases by 1% per year until 2030 and is then held level until 2045

Batavia Native Load Subcases



Source: 2024 gross load calculated using net load, distributed solar installed capacity, and EV penetration data from Batavia. See following slides for explanation of the calculation of EV and distributed solar contributions to load.

Distributed Solar Subcases

Distributed solar growth in the **Base Solar** subcase is based on solar growth projections by customer class in ComEd. In addition, we assume 3 MW of distributed solar additions (1 MW per year) from industrial customers by the end of 2027, in line with these customers' current development plans.

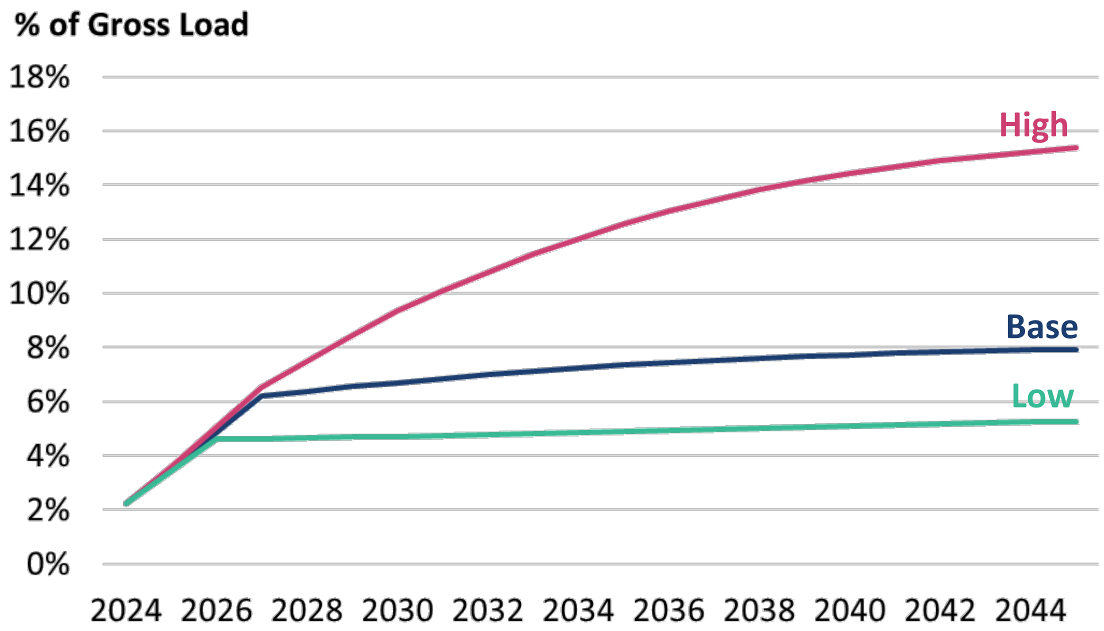
- The **High** and **Low** solar subcases are constructed using Batavia's historical solar growth over different time periods, plus assumed solar additions by industrial customers (2 MW of additions by 2027 in the **Low** subcase, compared to 3 MW by 2027 in the **Base** and **High** subcases)

In all subcases, we first develop forecasts for the annual installed solar capacity and then convert these capacity estimates to hourly data on contributions to load using solar generation profiles from NREL's PVWatts database (assuming Batavia as the installed location).

In the **Base** solar subcase, total installed capacity of distributed solar increases to 7.0 MW by 2045, or 7.9% of gross peak load. This means that if all solar was producing at its max volume during the peak hour, it would be able to serve nearly 8% of load. Actual generation may be lower due to tree shading, the angle of the sun, and misaligned timing of peak load and maximum irradiation potential.

In the **High** and **Low** solar subcases, distributed solar capacity is projected to increase to 12.7 MW and 5.4 MW by 2045, representing 15.4% and 5.3% of gross load, respectively.

Distributed Solar Installed Capacity As % of Gross Peak Load



Source: Capacity in the **Low Solar** subcase is reported as a percentage of gross load from the **High Load** case (and vice versa for solar capacity in the **High Solar** subcase), see Load Forecast Cases and Subcases used in Build-up of Cases for additional detail on cases and subcases.

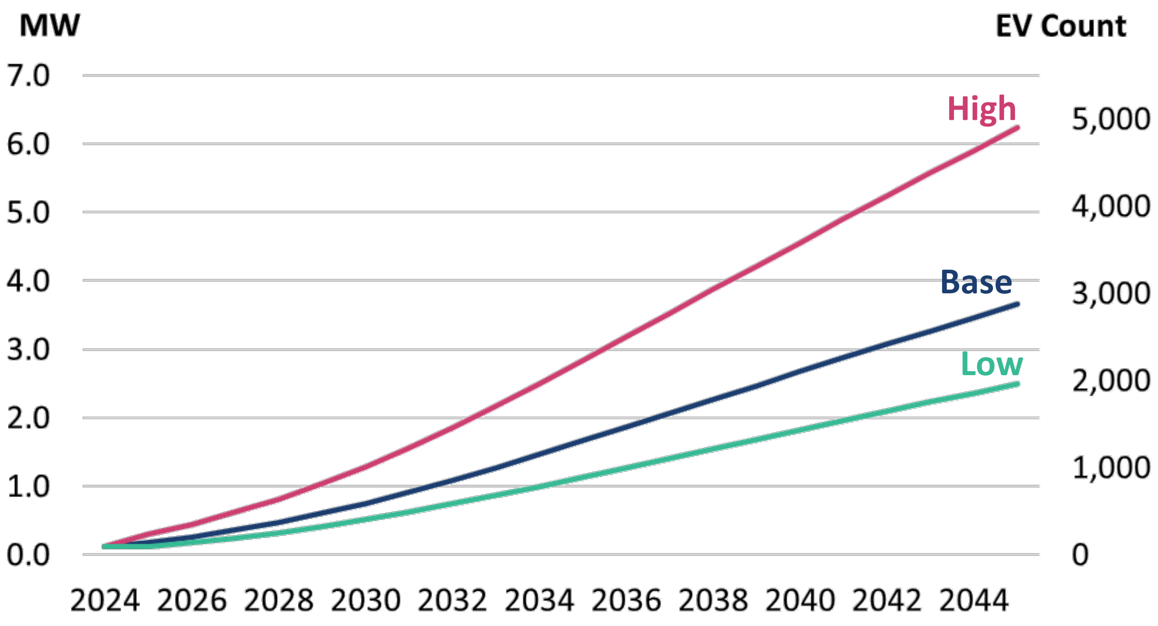
EV Charging Load Subcases

We used a two-step process to develop forecasts of EV contributions to system load. First, we project the growth in the number of total EVs in Batavia. We then multiply the number of EVs by hourly charging profiles from NREL's EV Infrastructure Toolbox to estimate load impacts, while also accounting for differences in EV type, charging locations (workplace versus home), and weekday versus weekend charging behavior.

Total EV adoption is projected to reach 15% by 2045 in the **Base EV** subcase, adding 3.2 MW to the peak load in 2045 (or 3.7% of gross peak). The bulk of charge load falls during evening hours and occurs after the periods of highest load (i.e., the afternoon).

Subcase	Description
High EV	• Assumed linear growth to achieve 25% EV adoption by 2045 • EV share by 2030: 5% (923 EVs)
Base EV	• Growth rates based on projections in ComEd (equivalent to 15% EV adoption by 2045) • EV share by 2030: 3% (541 EVs)
Low EV	• Assumed linear growth to achieve 10% EV adoption by 2045 • EV share by 2030: 2% (369 EVs)

EV Count and Contribution to System Load (MW)



Sources and notes: See appendix for additional detail on EV forecast methodology.

Projected Net System Load – 24 Hour Load Shape

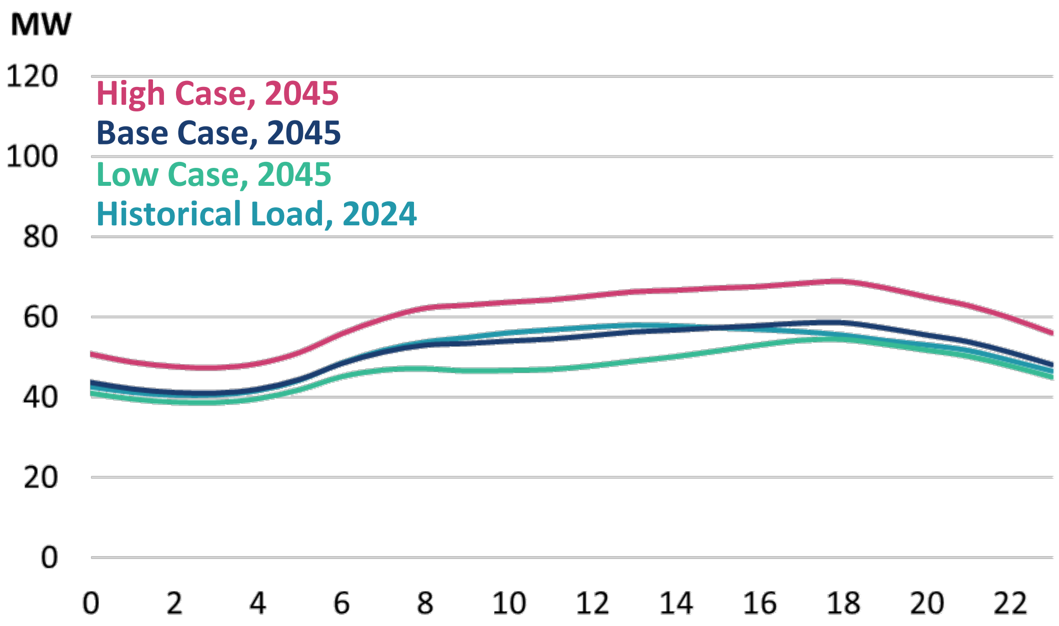
Increases in distributed solar penetration and EV charging load are forecasted to have small impacts on overall system load shape. Load shape remains consistent across cases.

In 2024, Batavia's diurnal load shape was largely flat, with a gradual ramp-up in the morning hours and a modest peak in the early afternoon. Both gross and net peak occurred in the afternoon of August 5th (2PM gross peak; 3PM net peak), reflecting Batavia's general summer-peaking load pattern, where demand peaks in the afternoon and early evening hours (around 1PM – 7 PM).

In 2045, the final year of the study period, load shape is similar, but the net peak period is shifted slightly later into the evening hours (3 – 8 PM), which can be attributed largely to the increased solar generation during the early afternoon. Similar to 2024 historical data, gross peak in 2045 occurs on August 5th at 3PM*, but the overall net peak occurs earlier in the summer (June 17th at 6 PM), when solar irradiation (and therefore solar generation) is lower than the August levels, leading to a higher net peak

While the increase in solar capacity is predicted to have a small impact on overall net load shape and peak hours, the growing number of EVs is expected to increase system load but not expected to dramatically change the peak period –many of these EVs will be charged during overnight hours, and not when the system load will be the highest.

Batavia 2045 Net Load Forecast, Annual Average by Hour (Weekday Only)



Notes: Figure above shows the projected annual average net load by hour in 2045 across all weekday hours. Data in teal shows the historical annual average net load by hour in 2024. See appendix for comparison of weekday and weekend load shape.

* For simplicity, we fix the calendar so the days of week for each date remain the same across years (e.g., if 1/1/2024 is a Monday, then Jan. 1st is treated as a Monday in each year) for our analysis.

Projected Gross and Net System Load

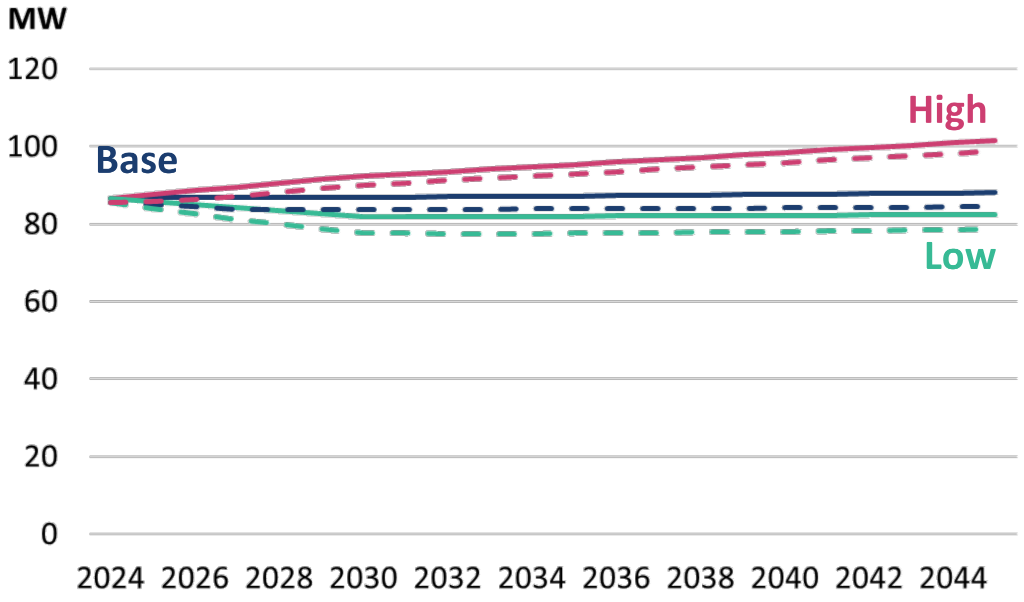
By 2045, system gross load and net load are projected to reach 88.0 MW and 84.6 MW in the **Base** case, 101.6 and 98.8 MW in the **High** case, and 82.5 MW and 78.6 MW in the **Low** case.

Despite increases in EV charging load, we expect that Batavia's overall net and gross peak load will not grow significantly during the study period, due to flat expectations of native load and the growth of distributed solar capacity.

Since Batavia's system load is not expected to experience significant growth, it is not necessary to procure new resources to meet this load growth. However, Batavia will continue to be exposed to market prices. If load does indeed grow (such as under the **High** Load case), then the exposure to market prices will increase and may incentivize new resource additions. Such exposure can be mitigated by the addition of a new resource, as discussed in later sections.

It is important to note that this analysis does not account for the potential addition of a 50 MW data center in Batavia, because planning for this data center was in early stages at the time of analysis. While the data center load is expected to be served through market purchases with all upfront costs for interconnection being paid by the data center, our final IRP analysis will model the potential cost and reliability implications of this data center.

Batavia Gross Load (Solid) and Net Load (Dotted) Projections



Notes: **High** Case refers to **High Native Load Subcase + Low Solar Subcase + High EV Subcase**. **Low** Case refers to **Low Native Load Subcase + High Solar Subcase + Low EV Subcase**. See Load Forecast Cases and Subcases used in build-up of Cases for additional detail on cases and subcases. Net load refers to Batavia's demand after reductions from behind-the-meter resources like rooftop solar.

Summary Load Forecast Results

We developed an hourly load forecast to understand how Batavia's gross and net system load will change over time. The load forecast results help inform how Batavia can most cost-effectively meet customers' demand for electricity. In addition to the **Base** case forecast, we also developed separate **High** and **Low** load cases to test various resource portfolios' robustness.

To assemble these load forecasts, we created separate forecasts of the following drivers and modifiers of load (referred to as "subcases" in this analysis): "Native" load (gross load, excluding EV charging load and distributed solar load reductions, which are forecast separately); distributed solar contributions to load; EV charging load; end-use electrification; and industrial load growth. Incremental electrification and load growth are not projected to change significantly during the study period, based on survey results from current Batavia customers.

The increased penetration of distributed solar and EV charging load will shift the net peak period slightly later in the day, into the late afternoon and early evening hours (roughly HB 3PM – 8 PM). Similar to 2024, the load during peak hours will be moderately higher than that in the shoulder hours, with the load shape not exhibiting a significant ramp-up or ramp-down period. The overall gross peak occurs in the afternoon hours of August 5th in both 2024 and the 2045, because the largest modifier of the gross load shape (that is to say, the largest of the modifiers considered in this study), EV charging load, mainly affects overnight system load (and not load during the peak period). The increased capacity of distributed solar will trigger a shift of the net peak period from August 5th to earlier in the summer (June 17th at 6 PM) when solar irradiation and generation are lower. Under the **Base** case forecast, the gross peak and net peak are expected to both remain similar to current levels—gross load grows slightly from 86.7 MW in 2024 to 88 MW in 2045, and net peak decreases slightly from 85.5 MW in 2024 to 84.6 MW in 2045.

Due to the lack of significant changes to load and the final load shape, there is no need to procure new resources to match load growth and/or changes in load shape, and the exposure to market price volatility is expected to remain similar to current levels. However, this analysis does not consider the potential development of a 50 MW data center because the project was in the early stages of planning at the time of analysis. The data center load is expected to be served through market purchases with all costs being paid by the data center. The final IRP study will evaluate the implications of this potential load addition. Should load grow significantly, like under the **High** load case, exposure to market prices (and price volatility) will increase and may incentivize the addition of new resources in Batavia.

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Overview

To serve its customers' electricity demand, Batavia relies on market purchases and its NIMPA contract, which gives Batavia the right to 55 MW of the capacity and energy output of Prairie State Generating Station.

- The NIMPA contract is a hedge against high energy and gas prices, but Batavia is still exposed to the highest energy prices when demand exceeds the size of the contract. When PSGC reduces output by 50% in 2038, NIMPA will replace half of the contracted amount with potentially more expensive market purchases.
- Reliance on market purchases of energy and capacity creates cost risk for ratepayers. Batavia has experienced high energy and capacity market prices in the last three years.

PJM energy prices depend on natural gas prices because natural gas-fired generation is often the marginal resource. We assume this dynamic will hold in the future because new coal resources are unlikely to be built and unless PJM system fully decarbonizes (i.e., transition to a generation portfolio that completely excludes carbon emitting assets), natural gas generation would likely continue to be marginal. Our energy price outlook is based on natural gas price outlooks combined with implied market heat rate (IMHR) outlooks derived from recent market forwards and public price forecasts. The IMHR is a measure of the average efficiency of the marginal generating unit, assuming it is natural gas-fired, and is indicative of the relationship between natural gas prices and energy prices.

- We expect gas prices to increase in the short term as the demand for liquefied natural gas (LNG) increases, driving up energy prices. High load growth outpacing generation additions will put less efficient (more expensive) natural gas-fired generation on the margin more frequently, thereby increasing the IMHR and exerting upward pressure on energy prices.
- On the other hand, increasing deployment of low and zero variable-cost resources like renewables to meet CEJA requirements would displace the most expensive natural gas-burning resources from the supply stack, lowering the IMHR and creating downward pressure on energy prices.

We use forecasted gas, energy, and capacity prices to estimate the potential cost increases of Batavia's future market transactions and evaluate the potential hedging value of supply- or demand-side resource additions. We developed three scenarios to help Batavia weigh its risks and hedging strategies under various possible market evolutions.

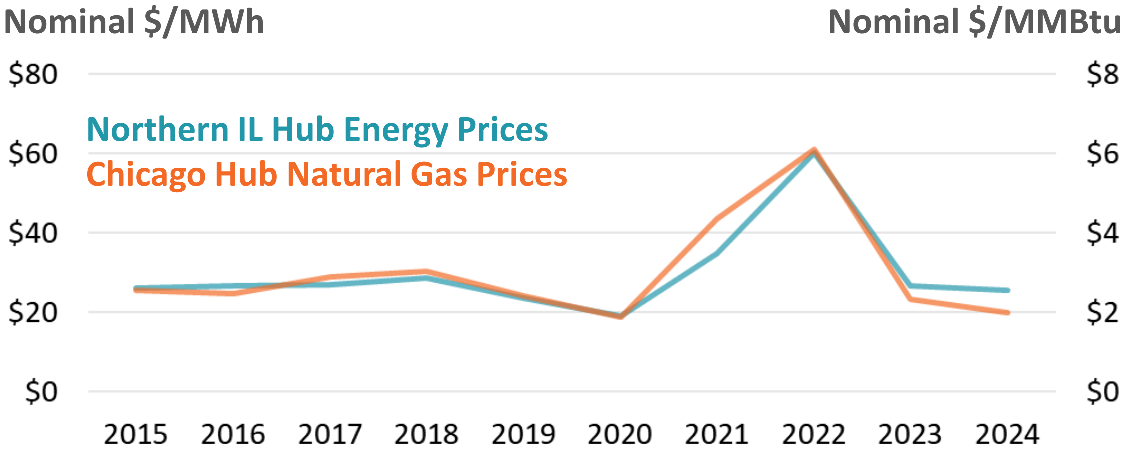
Notes: The IRP analysis relied on publicly available data sources, excel-based calculations, and transparent analytical methodologies. No proprietary computer models subject to restricted access were used.

Historical Energy Prices

Batavia relies on the PJM energy market to purchase energy when its net load is greater than supply from the 55 MW NIMPA contract, which typically happens during high-priced evening hours. Batavia's participation in the energy market means that its energy expenditures, which are passed through to ratepayers, can vary meaningfully with peak energy market prices.

- Between 2015-2020, average annual energy prices have consistently been between $25-30/MWh, creating predictability in Batavia's energy market expenditures. However, energy price volatility in 2021-2022 more than doubled the per-MWh cost of Batavia's market purchases relative to 2019.
- In the PJM market, energy prices are closely correlated with natural gas prices. Energy prices are set by the marginal, or most expensive unit needed to serve electrical demand, which is often a natural gas-fired resource.
- The spike in energy prices in 2022 correlated with a spike in natural gas prices caused by Russia's full-scale invasion of Ukraine.

Historical Energy and Natural Gas Prices, 2015-2024



Note: Northern IL Hub Energy Prices and Chicago Hub Natural Gas prices are an average of monthly prices from S&P Capital IQ.

Relationship of Energy Prices And Natural Gas Prices: 1/2

The relationship between energy and the marginal fuel (fuel used for the marginal generation) prices (energy price divided by the natural gas price) is referred to as the implied market heat rate ("IMHR").

- IMHR is a similar concept to "fuel mileage of a car" (miles per gallon) but for a fleet (i.e., all generators/cars that are part of the market), rather than individual generators/cars.
- Using IMHR simplifies the analysis because it helps take out the impact of changes in the marginal fuel price.
  - IMHR will maintain the merit order of generators.
- Natural gas is considered the marginal fuel for most deregulated energy markets in the U.S., including PJM which Batavia is part of.
  - In other words, energy prices is expected to be highly correlated to natural gas prices.
- The IMHR depends on the balance between generation supply and demand.
  - The IMHR generally increases when demand grows or lower cost generation capacity decrease (e.g., due to retirements).
  - The IMHR generally decreases when lower cost generation capacity is added (this can also be through imports into the region) while load remains unchanged.
  - Thereby, the IMHR increases if demand growth outpaces the net additions of low-cost supply (either efficient thermal generation or zero marginal cost renewables). If net-additions of low-cost generation capacity outpaces load growth or if the import transfer capability increases for a region, the IMHR would decrease.
- Given the above, studying IMHR helps understand how energy market prices would change, as the resource mix and load evolve.

Relationship of Energy Prices And Natural Gas Prices: 2/2

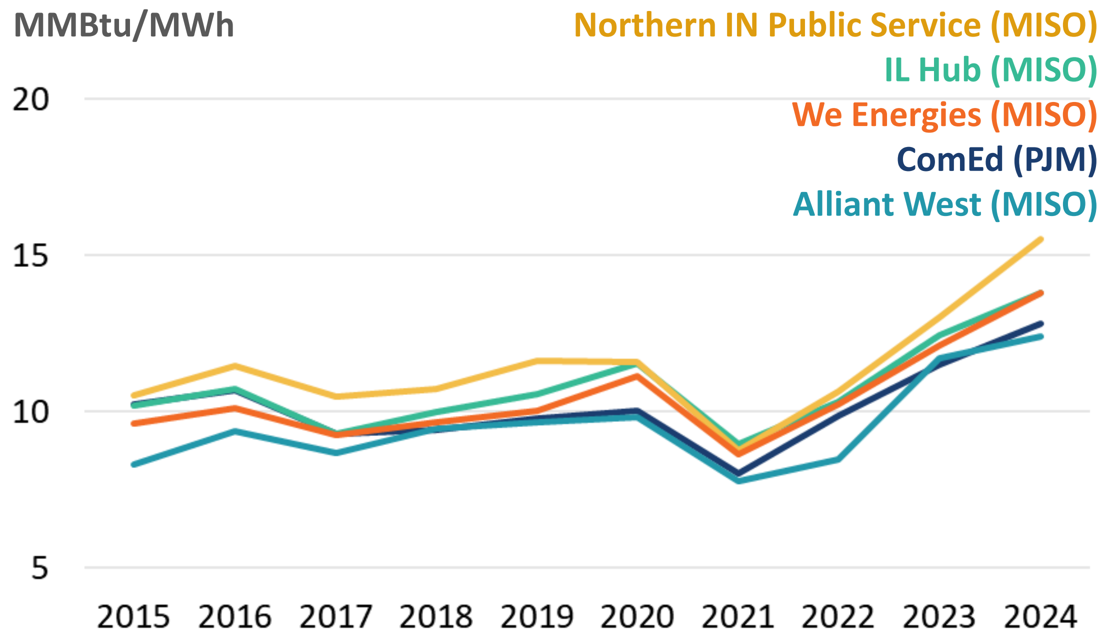
The IMHR in PJM's ComEd region (where Batavia is located) has remained steady between 2015-2022, with similar trends in neighboring parts of the Midwest Independent System Operator (MISO) market.

- ComEd shows lower IMHR compared to its neighbors (except Alliant West in wind-rich Iowa). Constellation Energy's nuclear plant fleet located within the ComEd service territory is likely contributing to this.

The future of ComEd energy prices remains uncertain.

- Since 2022, the ComEd region's IMHR has been increasing as load growth (much driven by new data centers) has been outpacing additions of efficient generation capacity. The increase in IMHR can increase Batavia's exposure to energy cost risk if it persists in the future. An increase in renewable deployment to meet CEJA regulations could offset the IMHR increases.
- ComEd may face additional upward price pressure if its export demand into MISO grows.

Historical Implied Market Heat Rates in ComEd and Neighbors



Note: Market heat rates derived from energy and natural gas prices from S&P Capital IQ.

Market Price Outlook Development

1

Develop Natural Gas Price Outlooks

Develop the trajectory of future natural gas prices using natural gas forwards and price projections from the EIA's Annual Energy Outlook (AEO). We develop three cases: a **Base Case**, a **High Case**, a **Low Case**.

2

Develop Implied Market Heat Rate Outlooks

Synthesize natural gas and energy forwards with price projections from the AEO to assess how changes in the future generation mix and load will influence the relationship between energy and gas prices in all three cases.

3

Develop Energy Price Outlooks

Combine the market heat rate and natural gas projections from Steps 1 and 2 to develop energy prices in all three cases.

4

Develop Capacity Price Outlooks

Estimate capacity prices, assuming they will reflect the marginal cost of new entry and that resource costs will increase with inflation. Use energy and gas prices to project energy and ancillary services revenues used in the capacity price calculation.

Natural Gas Price Outlooks

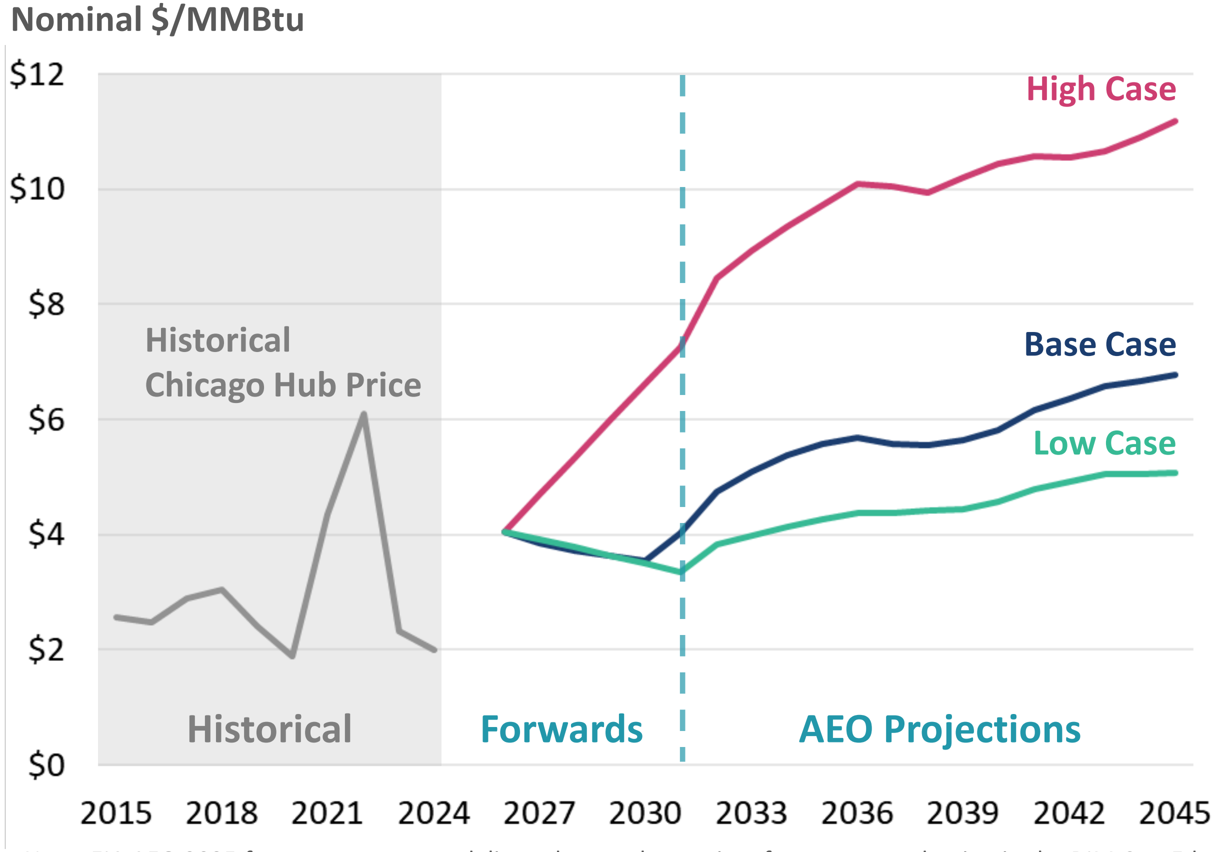
We developed natural gas price outlooks using short-term forwards from MI Forwards (March 2025) and long-term projections from the US Energy Information Administration's (EIA) 2025 Annual Energy Outlook (AEO).

- Market forwards represent traders' expectations for future natural gas prices. Forward prices are set months to years in advance of natural gas delivery and indicate the price that market participants are willing to "lock in" to mitigate potential future price risk.
- The AEO's natural gas prices are based on long-term market modeling done by the EIA to serve as a broadly accepted universal reference point for system planning and hedging purposes.

The AEO projects a rapid natural gas price increase in the 2030s due to rapid growth of demand for liquefied natural gas (LNG) and the exhaustion of the most cost-effective wells. This increase would push electricity prices up in the mid-2030s, potentially increasing Batavia's exposure to high electricity prices (though the NIMPA contract provides a partial hedge).

- Our **Base Case** assumes forward prices through 2030 and adopts the AEO Reference case natural gas forecast thereafter.
- Our **High Case** assumes that low gas supply will push natural gas prices up based on the AEO's "Low Oil and Gas Supply" case.
- Our **Low Case** assumes a higher supply of gas than the Base Case based on the AEO's "High Oil and Gas Supply" case.

Historical And Projected Chicago Hub Natural Gas Prices



Note: EIA AEO 2025 forecast represents delivered natural gas prices for power production in the PJM ComEd LDA, which contains Batavia and the Chicago Hub. Chicago Hub Forwards are from the MI Forward index of real forward prices as of March 2025.

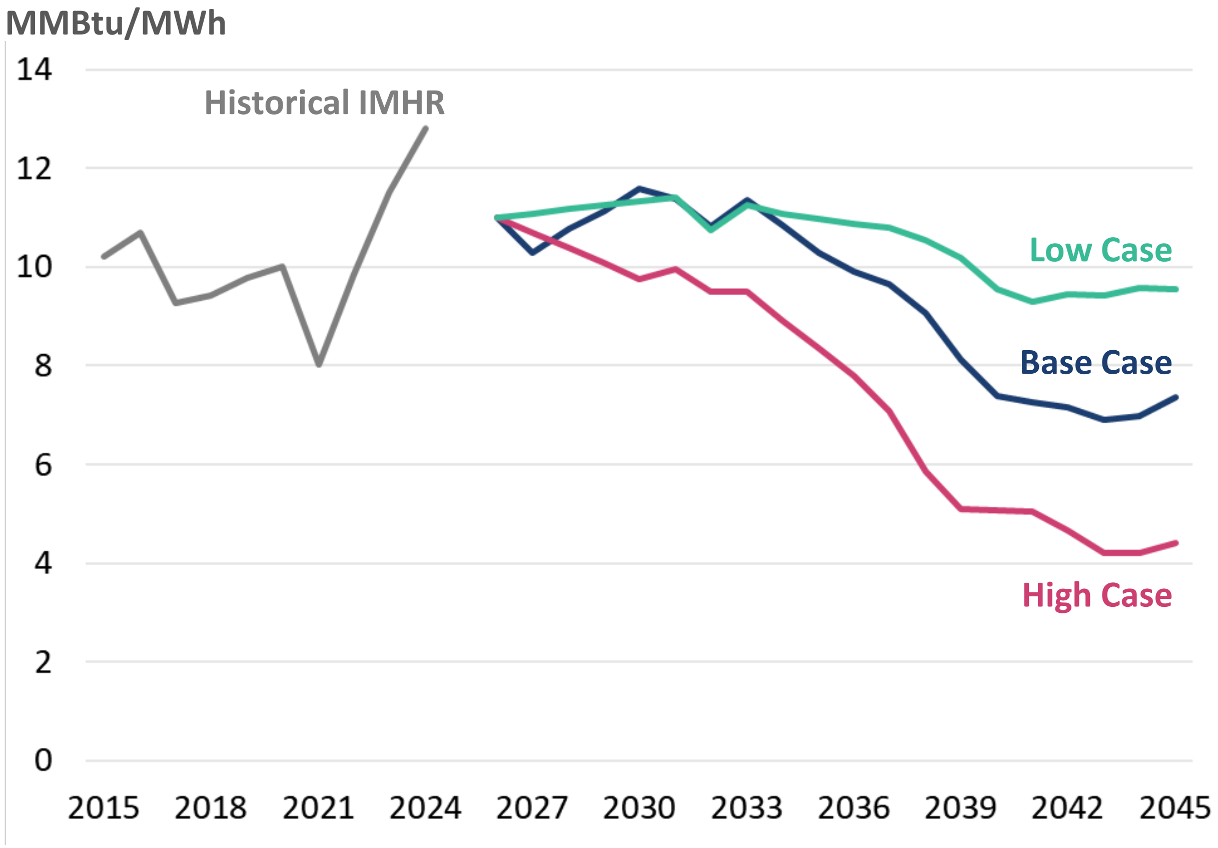
Implied Market Heat Rate Outlooks

We develop IMHR outlooks to capture how the efficiency of the PJM energy market could change over time with retirements of fossil fuel resources and renewable additions. Our outlooks are anchored in electricity and natural gas market forward data (as of March 2025), with modifications based on the EIA AEO's projected trends gas and electricity prices. We later use gas prices and the IMHR to calculate energy prices.

Based on EIA AEO projections, we expect the ComEd IMHR to decrease, reflecting an uptake of renewables and retirement of thermal resources in response to CEJA. This could offset upward pressure on electricity prices from rising gas prices.

- In the **Base Case**, electricity prices increase relative to gas prices through the early 2030s. More renewables come online in the late 2030s in response to high gas prices, resulting in a lower IMHR.
- In the **High Case**, high natural gas prices in the 2030s increase electricity prices, driving increased uptake of renewable generation resources in the mid-late 2030s. As a result, more efficient natural gas-fired resources are marginal more frequently, decreasing the IMHR.
- In the **Low Case**, a high supply of natural gas keeps gas prices low and stable, keeping electricity prices low and reducing the incentive to build renewable generation resources. As a result, the efficiency of the marginal natural gas-fired resource does not decrease as quickly as in the other Cases, slowing the decrease in IMHR.

Historical And Projected Implied Market Heat Rates



Note: Historical IMHRs are derived from monthly average Northern IL Hub energy prices and Chicago Hub gas prices. Forward IMHRs are derived from MI forward index of real forward prices as of March 2025 for Northern IL Hub energy prices and Chicago Hub gas prices.

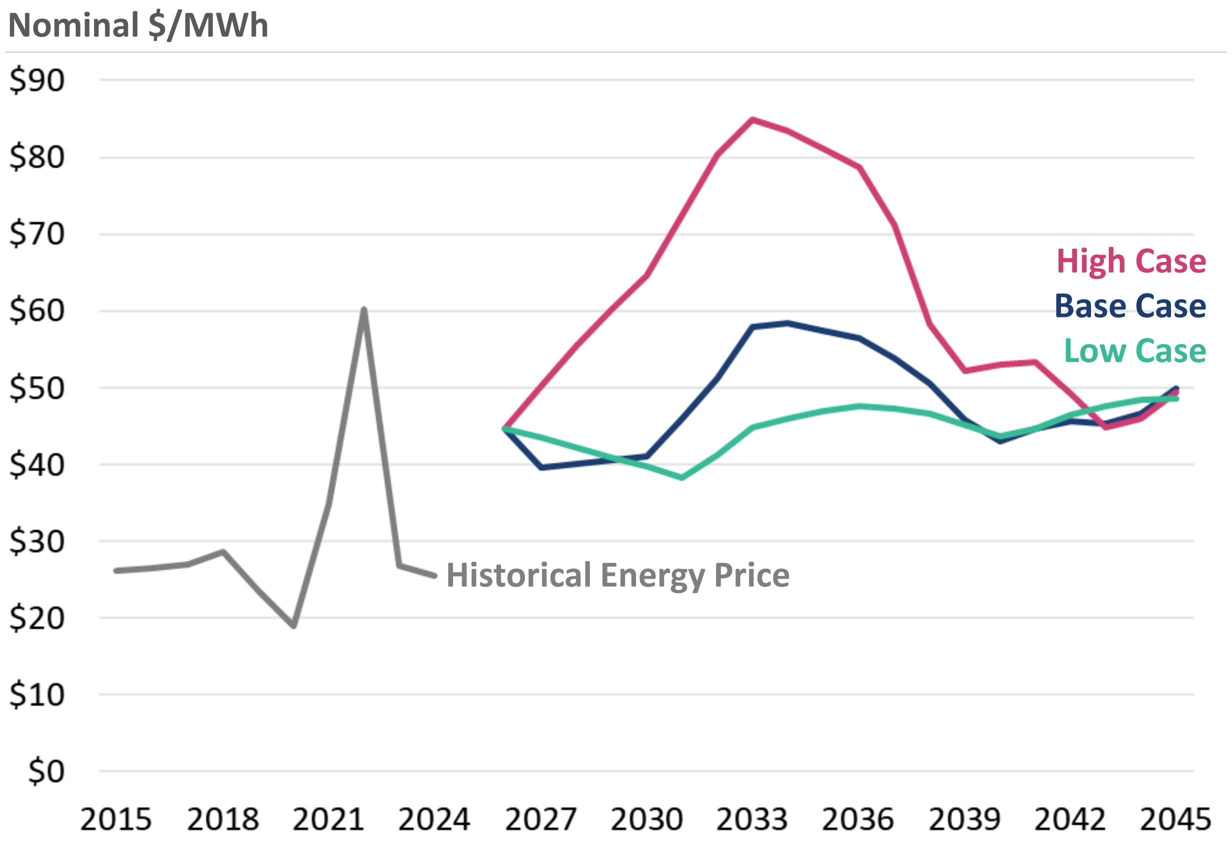
Energy Price Outlooks

We develop energy price outlooks by multiplying our natural gas price and IMHR outlooks together.

In the mid 2030s, rising natural gas prices could cause energy prices to triple relative to 2024 levels, increasing Batavia's cost of energy market purchases. Later, accelerating renewable deployment in response to high electricity prices and anticipation of CEJA's natural gas generation phase-out in 2045 could lower the ComEd IMHR and bring energy prices down.

- In the **Base Case,** a stable IMHR and gas price keeps energy prices flat in the late 2020s/early 2030s before high gas prices increase energy prices in the mid-2030s. In the late 2030s, energy prices decrease due to increased adoption of renewables in response to higher prices.
- In the **High Case**, electricity prices spike in the late 2020s and early 2030s, driven by rapid increases in natural gas prices. In response, more renewables are built in the mid/late 2030s, reducing the cost of generation.
- In the **Low Case**, energy prices remain stable as modest increases in natural gas prices get cancelled out by gradual decreases in IMHR.

Historical And Projected Energy Prices



Note: Developed from projected IMHR and gas prices in each scenario.

Overview of PJM Capacity Market

Capacity price forecasts will help Batavia to evaluate the tradeoffs of relying on market capacity purchases or procuring supply to cover peak demand beyond the NIMPA contract capacity.

Load serving entities like Batavia are required to purchase enough capacity to cover their peak load (including capacity reserve margins) from PJM's capacity market (RPM)[1]. Capacity payments can be thought of as a "retainer" paid by load serving entities to generators to compensate them for their *ability* to cover peak load, even if they do not operate all the time.

- The capacity revenue a resource receives is based on its "unforced capacity" (UCAP), which considers how likely the resource is to be available to cover peak load. UCAP is calculated by adjusting a resource's installed capacity (ICAP) by its Effective Load Carrying Capacity (ELCC, expressed as a percentage), which considers capacity derates and fluctuations in output levels (for variable renewables).
- Batavia must purchase enough capacity in UCAP terms to meet its peak load, adjusted for a reserve margin.

The capacity market is designed to incentivize construction of new generation needed to maintain reliability by covering generators' capital and operating costs that cannot be made up from revenues in the energy and ancillary service markets, or to allow recovery of fixed costs when the market has a surplus of capacity.

- The difference between a new resource's levelized annual costs and its energy and ancillary service revenues is the Net CONE.
- The capacity market is an auction where each resource places a bid for the right to receive a capacity payment. The capacity price that all resources receive is the bid of the *marginal resource*, or the most expensive resource needed to meet total capacity needs.
- PJM's capacity market is conducted within smaller regional "capacity zones." Batavia is in the "ComEd" zone, which consists of most of Northern IL.

Load serving entities can procure capacity outside the market through outright resource ownership or through agreements like the NIMPA contract.

- The NIMPA contract gives Batavia the right to 55 MW of *firm* capacity, reducing its UCAP procurement obligation directly. Batavia must procure its remaining capacity from the market.

Note:[1] PJM has recently been discussing changes to the RPM. See Appendix for further details.

Capacity Price Assumptions

We estimate PJM capacity prices assuming that recently observed market volatility will pass, and that capacity prices will settle at the net cost of new entry (CONE) for a gas-fired combined cycle (CC) or combustion turbine (CT) by 2030. We assume that the capacity price will always be equal to the Net CONE of the lower-cost resource.

- Net CONE = Investment Costs (*Gross* CONE) – Energy and Ancillary Service (E&AS) Revenue Offset.
- We assume that investment costs increase with inflation in all scenarios based on the EIA AEO GDP deflator (average 2.1% annually). From 2026-2045, the GDP deflator indicates that costs will rise by 48%.

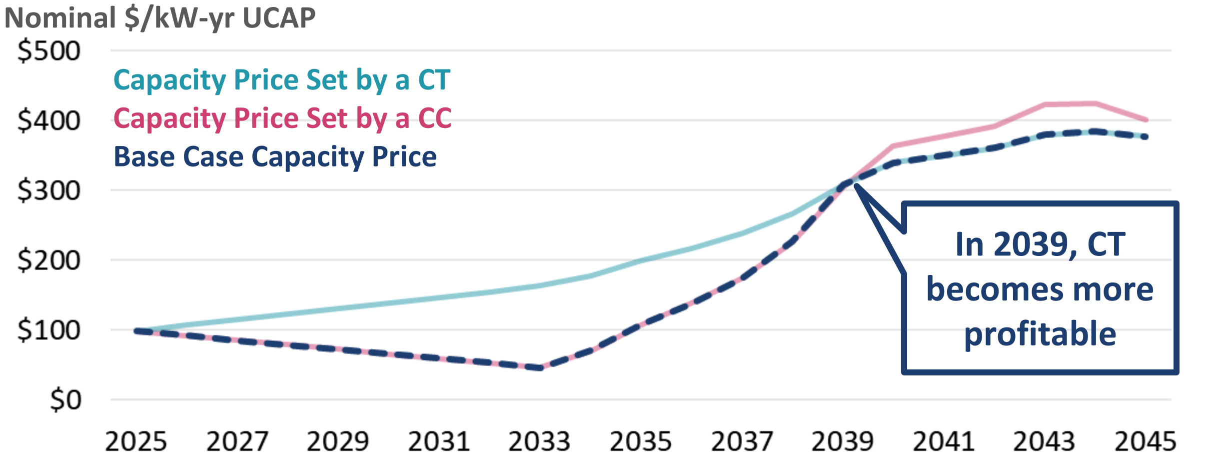
To determine the capacity price, we calculate the E&AS offset using our energy and natural gas price outlooks.

- Since the projected capacity prices depend only on the E&AS offset, capacity price is determined by the **profitability** of the resource, i.e., the difference between energy prices and gas prices.

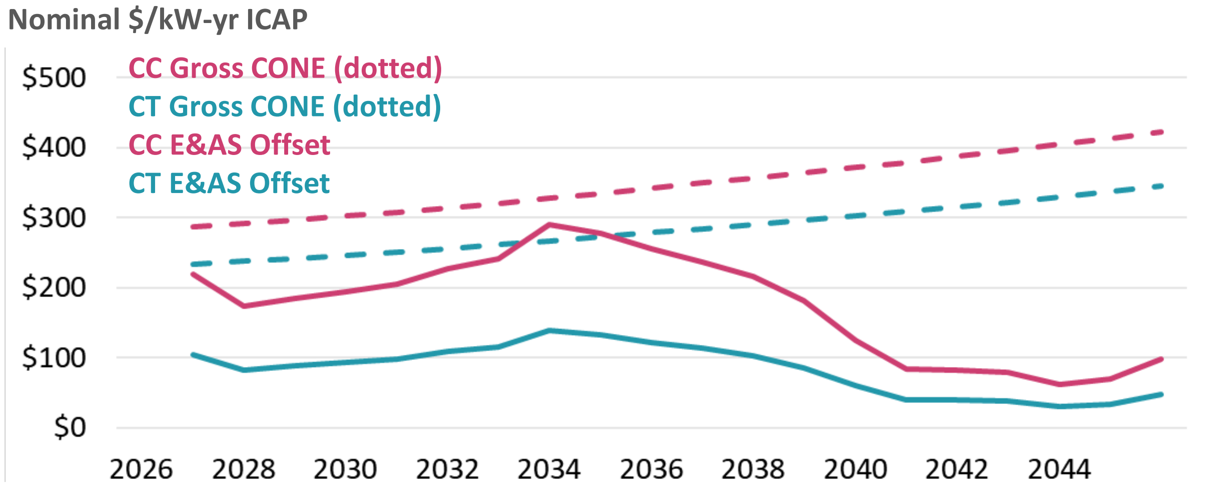
Finally, we assume that, since capacity revenues from Prairie State are passed-through to Batavia via the NIMPA contract, Batavia's capacity procurement obligation is decreased by 55 MW UCAP.

- Post-2028, PSGC's capacity accreditation remains uncertain; even if both units remain in service, operating at reduced output levels may result in lower capacity accreditation. Accordingly, this IRP assumes Batavia's capacity procurement obligation decreases by 27.5 MW UCAP in 2038 (50% of the current reduction).

PJM RTO Capacity Prices By Reference Technology (Base Case)



PJM RTO Capacity Price Components



Capacity Price Outlook

Capacity prices depend on resource *profitability*, which is dictated by the relationship between energy prices and gas prices. Put another way, the IMHR and capacity price have an *inverse* relationship.

In the **Base Case**, electricity prices spike while gas prices increase modestly, decreasing capacity prices from 2026-2033 while increasing the IMHR. After 2033, electricity prices drop while gas prices remain high, decreasing the IMHR and increasing the capacity price.

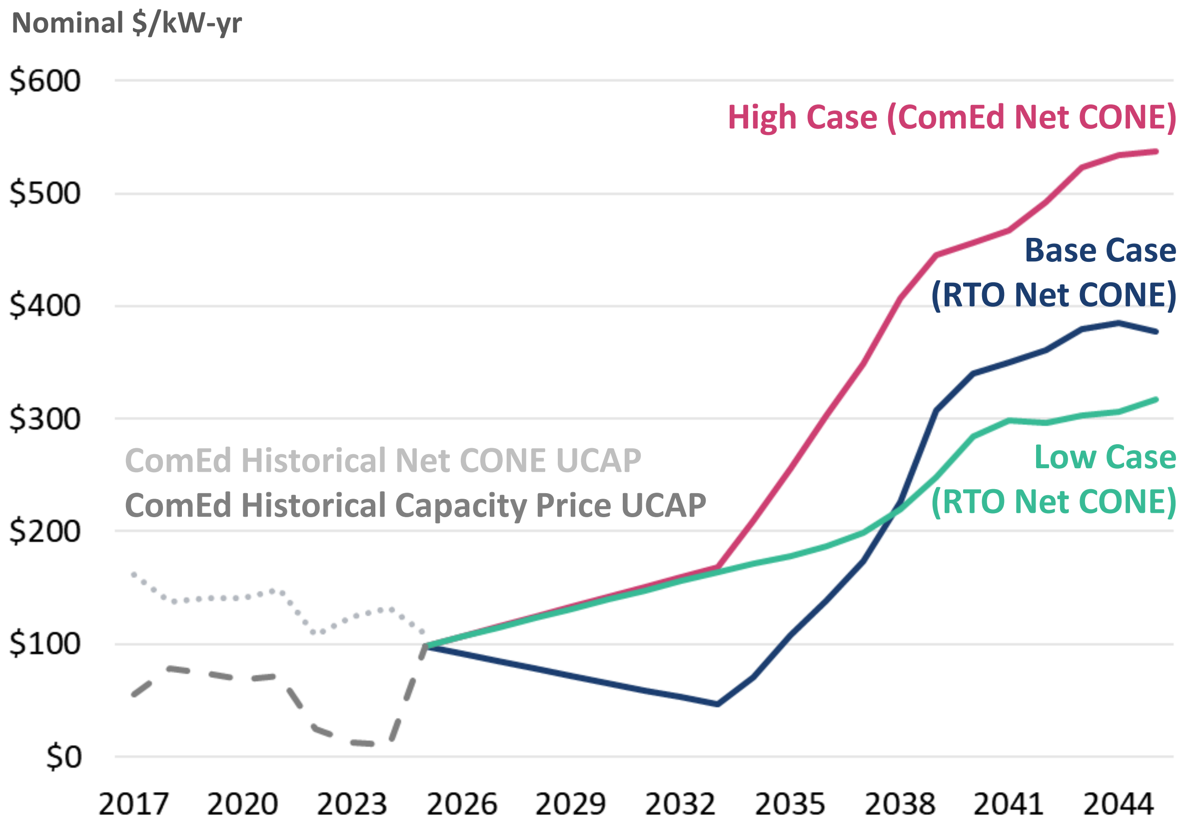
In the **High Case**, capacity prices increase from 2026-2033 since the ComEd Net CONE is higher than the RTO Net CONE, and market prices must increase to reach it. After 2033, electricity prices drop significantly while gas prices increase steadily, causing the capacity price to spike to over 5x what it was in 2025 as the IMHR drops by a similar degree.

- The Net CONE in ComEd is higher than the RTO Net CONE since capital costs are higher and CEJA limits the operating life of new combustion turbine (CT) and combined-cycle (CC) generation resources.

In the **Low Case**, electricity prices decrease faster than gas prices from 2025-2040, increasing the capacity price as the IMHR decreases. After 2033, energy and gas prices increase steadily at similar rates, keeping profitability and thus the capacity price constant through 2045.

In the **high case**, we assume that ComEd price-separates due to resource constraints, meaning that Batavia must pay a higher, ComEd-specific capacity price rather than the PJM-wide capacity price.

ComEd Capacity Price Forecast



Note: Values show capacity prices in unforced capacity (UCAP) terms. This analysis was completed in advance of and thus does not reflect the 2026/27 Base Residual Auction results.

Summary of Market Price Forecasting Results

Forecasted energy prices could double relative to their current levels, increasing Batavia's cost of market purchases.

- High gas prices will also increase Batavia's cost to serve load after PSGC reduces output by 50%, as Batavia will have to pay for a larger volume of market purchase at a higher cost.
- We adopt the EIA AEO assumption that high demand for LNG will be the largest near-term driver of gas prices.

Moreover, the capacity price in the ComEd zone could increase by 3-5x relative to today's levels, potentially increasing costs for Batavia's ratepayers.

- Political and market developments like artificial price caps will affect the ultimate capacity prices, as PJM faces pressure from stakeholders for market reform. Restrictions on capacity prices through out-of-market political actions like price caps effectively put a ceiling on capacity market costs, meaning that Batavia's cost to serve load could be lower than current projections, which are based primarily on market factors.

Batavia's exposure to these market prices will increase after Prairie State Unit 1 reduces output by 50% in 2038, at which point the City will need to procure more energy and capacity from the market. Because capacity prices are expected to have the largest potential impact to Batavia's cost of serving load, hedging these costs should be a priority. Batavia can reduce its exposure to capacity prices in two key ways:

- First, by procuring a supply-side resource, either by ownership or contract, and securing the rights to its capacity;
- Second, by reducing peak load (and thus Batavia's capacity procurement obligation) through demand-side management programs.

Procuring supply-side generation or reducing the need for market purchases through demand-side programs hedges Batavia against high energy prices:

- A supply-side resource gives Batavia access to energy at a lower cost;
- Demand-side programs reduce demand, especially in peak hours, reducing Batavia's exposure to the highest energy prices.

Since capacity prices will likely increase more than energy prices, procuring a supply -side resource that earns more revenue from capacity will allow Batavia to maximize its savings by maximizing that resource's net revenues.

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Resource Portfolio Selection

The combination of the NIMPA contract and market purchases is sufficient to meet Batavia's customer electricity demand, but that strategy exposes Batavia to price risks in increasingly volatile capacity and energy markets. Moreover, Batavia is not protected against unforeseen load growth, a sudden loss of Prairie State generation, or policy changes that restrict Prairie State's ability to generate power.

Adding a new supply-side resource to Batavia's portfolio could help the city reduce its cost of serving load. A supply-side resource could help Batavia meet its energy needs at a lower price relative to market purchase and could reduce exposure to price volatility in the energy and capacity markets by:

- Decreasing Batavia's procurement obligation in the capacity market
- Providing Batavia's customers with energy cost-effectively, especially during high-priced hours (e.g., hot summer days)

Batavia can also sell the resource's output when it is not needed to serve the City's load, earning revenues in the energy market and reducing its overall cost of service.

Because affordability is a key consideration for Batavia, we evaluated candidate resources based on their ability to manage exposure to energy and capacity market volatility. Resource options were also assessed qualitatively against the City's broader planning priorities of resiliency, sustainability, and adaptability.

Resource Portfolio Evaluation Factors and Preferences

Evaluation Factor	Description	Batavia's Preference
1. Ownership Structure	Owned vs. Contracted	Flexible
2. Resource Location	Resource can be sited in City, county, state, , PJM, or outside of PJM	Prefer local
3. Resource Diversity	One versus multiple resources	Well-balanced, diversified portfolio
4. Hedging Policy	Max short and long positions allowed	No formal policy; prefer to not "play" in the market
5. Time to Connect	Prioritize resources that can be built and connected quickly	N/A (NIMPA contract still has 20+ years)
6. Timing	When to acquire resource	N/A (NIMPA contract still has 20+ years)
7. Technology Maturity	Appetite for established vs. emerging technology	Prefer proven/reliable technology

Supply-Side Resource Options Not Considered

We eliminated the following resource options from consideration due to cost, resource availability, technological maturity an d environmental reasons.

Category	Resource Type	Reasons Technology Is Not Considered For Batavia's Portfolio
Natural Gas & Hydrogen	Gas Turbine (Simple- or Combined-Cycle)	Minimum capacity is often larger than Batavia's needs, GHG emitting and will have limited lifespan under CEJA; may require gas pipeline connection
	Gas Resource With Carbon Capture	Nascent technology; high costs and large minimum capacity
	Hydrogen Resource	Nascent technology; high costs; policy uncertainty; may require expensive delivery network
Coal	Coal Steam Turbine	Emitting generation source, will have short lifespan due to CEJA regulations; no new builds
Nuclear	Advanced Nuclear	Nascent technology; high costs
Renewable	Geothermal[1]	Nascent technology; little geothermal resource near Batavia
	Concentrated Solar Power	High costs; local solar resource is relatively small
	Hydropower	Illinois has little remaining untapped hydro resources
Storage	Pumped Hydro Storage	Not topographically viable in Illinois; requires large-scale investments
	Battery/long duration energy storage (Beyond 4-Hour Duration)	Limited use case in PJM/Midwest at the moment (recommend to monitor)
	Flywheels	Low energy (MWh) capacity used for grid balancing, limited use case in PJM
	Compressed Air Storage	Requires geological formations not available near Batavia
	Gravity Storage	Emerging and largely unproven technology

Notes: 1: See Geothermal Electricity Generation for more details.

Supply-Side Resource Options Considered

We narrowed the list of supply-side resource options down to battery energy storage system (BESS), solar, wind, solar + battery storage, or a natural gas reciprocating internal combustion engine (RECIP) facility.

We recommend Batavia consider these supply-side options because:

- The technologies are flexible, mature, CEJA-friendly, available in small (<20 MW) capacity increments, and can be owned or contracted
- They have different use cases as hedges against capacity price and energy price (short term and long term)

While contracting a resource can be convenient, such an arrangement may prevent Batavia from capturing the resource's value as a capacity hedge if the owner wishes to keep what are projected to be increasingly high capacity revenues. Therefore, Batavia should consider either building the resource itself or guaranteeing that capacity revenues are passed to Batavia under a contract.

Indicative Supply-Side Resource Outlooks For The Year 2030

Technology	2030 LCOE (2022$/MWh)	Use Case	Energy Market Modeling Approach	2030 ELCC (%)	Economic Life (yrs)
4-Hour Battery	-	Capacity and energy hedge	Batteries reduce Batavia's exposure to volatile energy market prices by discharging during peak hours, but charging costs reflect losses and may be volatile if charging from the grid.	49%	20
Standalone Solar	\$35-\$49	Energy hedge	Non-emitting; zero marginal cost; but output is variable (wind has a higher capacity factor relative to solar)	6%	20
Standalone Wind	\$28-\$37			23%	20
Solar + 4-Hour Battery	\$65-\$99	Capacity and energy hedge	Can reduce exposure to high energy and capacity market prices by shifting renewable energy to peak periods	-	20
Natural Gas RECIP	\$30-\$70	Capacity and energy hedge	Flexible supply, relatively low upfront costs but GHG emitting	92%	30

Notes: Levelized Cost of Energy (LCOE) from NREL 2024 Annual Technology Baseline. RECIP costs are based on industry experience, as these values are not listed in the ATB. Battery technologies do not have LCOE values because they do not generate energy. RECIP values in LCOE column reflect per-MWh cost of fuel only and vary with natural gas prices. Actual RECIP LCOE would be higher. ELCCs from PJM, Preliminary ELCC Class Ratings for Period Delivery Year 2026/27 – Delivery Year 2034/35, 4/24/2025.

Performance of Portfolio Options & Policy Pillars

Consistent with the Municipal and Cooperative Electric Utility Planning and Transparency Act (HB2902) and Batavia's adopted Energy Policy, resource options in this study are qualitatively evaluated based on their relative contributions toward the City's four energy planning priorities: **affordability**, **resiliency**, **sustainability**, and **adaptability**.

Resource options may provide different levels of benefit across the City's planning priorities, which are not necessarily weighted equally across all technologies. Accordingly, the framework is intended to illustrate relative strengths and tradeoffs rather than identify a single preferred resource option.

Batavia Priority	What It Represents in the IRP Context	Example Benefits Reflected in Resource Evaluation
Affordability	Expected impact on customer electric costs, long-term rate stability, and exposure to fuel or market price volatility	Lower long-term system costs, stable customer rates, fuel diversification, and reduced market price exposure
Resiliency	Ability to support reliable electric service, maintain adequate energy supply, and respond to changing system or market conditions	Reliable service during extreme weather and peak demand events, operational flexibility, dispatchability, and reduced outage or market exposure risk
Sustainability	Alignment with CEJA and broader state clean energy and emissions reduction objectives	Reduced emissions, increased use of clean energy resources, and support for long-term environmental goals
Adaptability	Ability to flexibly respond to changing technologies, future energy needs, evolving regulations, and long-term planning uncertainty	Scalability, phased implementation opportunities, flexibility to support future load growth and new technologies, and ability to adapt to evolving market and policy conditions

Performance of Portfolio Options & Policy Pillars

The table below compares how the resource options currently being considered in the IRP may support Batavia's four energy planning priorities. The intent is to provide a simple and transparent way to illustrate the relative benefits and tradeoffs associated with each resource option.

The star ratings are qualitative and directional: more stars generally indicate that a resource may provide stronger benefits toward a specific planning priority relative to the other options being considered.

Batavia Priority	4-Hour Battery Storage (BESS)	Standalone Solar PV	Standalone Wind	Solar + 4-Hour Battery	Natural Gas RECIP	Demand Response	Electric Vehicle Programs
Affordability	★★	★★	★★	★★	★★★	★★	★
Resiliency	★★★	★	★	★★★	★★★	★	★
Sustainability	★	★★★	★★★	★★★	★	★★	★★★
Adaptability	★★	★★★	★★	★★★	★★★	★	★★
	Supply-Side					Demand-Side	

Note: Explanations for ratings provided in Appendix F.

Evaluation of Resource Options

We assume that Batavia would operate a new resource economically to respond to wholesale market hourly price signals, rather than replacing its market purchases.

- The new resources augment Batavia's market purchases, allowing the City to operate them in a manner that maximizes economic efficiency and ultimately the economic benefit to Batavia's customers.

The value of each candidate resource depends on its costs and revenues, including:

- Capital, operation, and maintenance costs
- Fuel or energy costs (where applicable)
- Energy and capacity market revenues

We calculated each resource's total benefit (or cost) to Batavia on a Net Present Value (NPV) basis over the study period (2026-2045)

- The NPV is a measure of the resource's total profitability (or cost) in today's value, considering that future profits are less valuable than profits today
- If a resource's NPV is positive, Batavia will reduce its cost to serve load by procuring that resource on top of market purchases. If the resource's NPV is negative, then it will cost Batavia more to procure the resource than to only purchase from the market.

We assumed that candidate resources are fully financed by municipal bonds issued at par, using the 4.35% interest rate from Batavia's most recent issuance as the discount rate.

While this IRP presents the costs and benefits of a 10 MW resource, all present values can be scaled linearly to other resource sizes.

Resource Cost and Revenue Development

Capital Costs

Capital costs include the costs of equipment, plant, construction, and financing. They are paid in equal mortgage-style payments over the plant's life.

We use capital costs from the NREL's Annual Technology Baseline (ATB) and the National Energy Technology Laboratory (NETL)'s Cost and Performance Baseline.

Fixed O&M Costs

Fixed Operations and Maintenance (O&M) costs do not depend on the plant's output, and include long-term service contracts, major maintenance, rent, and other consistent yearly expenses during operation.

We use fixed O&M costs from the NREL ATB and NETL, which escalate with inflation.

Variable O&M and Fuel Costs

Variable O&M costs depend on the level of power output and include daily fuel and emissions costs (for the RECIP), energy purchase costs (for the BESS), startup/shutdown costs, and any variable portion of service agreements.

We use simulated energy and gas prices along with performance characteristics from NETL and the ATB to calculate these costs. To calculate daily gas prices, we assume that daily gas price volatility follows 2024 patterns.

Energy Revenue

For renewable resources, we combine simulated hourly energy prices with production curves based on Batavia's wind speeds and solar radiation from Renewables Ninja and performance characteristics from the ATB.

We assume that the BESS will discharge in the four highest-priced hours each day, and the RECIP will generate when the market price of energy is greater than its variable cost.

Capacity Revenue

Each resource earns capacity revenue based on its class ELCC and the capacity price.

ELCCs are from PJM's most recent class ratings and are assumed to stay constant from 2034/35 (last year of PJM's data) through the end of the study period. We use the Diesel Utility ELCC as a proxy the RECIP ELCC

Notes: Since RECIP costs are not listed in the ATB, RECIP costs and performance characteristics are from National Energy Technology Laboratory, Cost and Performance Baseline for Fossil Energy Plants Volume 5: Natural Gas Electricity Generating Units for Flexible Operation, May 5, 2023.

Market Price Scenarios

To assess the lifecycle costs and revenues to serve Batavia's load with different supply-side resources, we combined the price projections described above with alternative load and technology cost trend scenarios.

Across the scenarios, we assume that natural gas prices are the fundamental driver of Batavia's load growth and market prices.

- The **High Market Price Scenario** assumes that high natural gas prices increase energy market prices and incentivize Batavia's customers to install rooftop solar while disincentivizing electrification (i.e., electric vehicle adoption). Batavia thus experiences lower load growth. In the energy market, high variable costs for natural gas-fired generation incentivize faster adoption of renewable resources, decreasing the IMHR. However, energy prices drop with increased renewable uptake, resulting in an increase in capacity prices.
- The **Low Market Price Scenario** assumes the opposite system dynamic, with low natural gas prices resulting in low energy market prices. Low energy market prices reduce the incentive for Batavia's customers to install rooftop solar and increase the attractiveness of electric vehicles as charging costs remain low, leading to high load growth. Low natural gas prices likewise reduce the economic advantage of renewable generation over fossil fuel-fired resources, resulting in a slower adoption of wind and solar in PJM and a sustained high IMHR. Low marginal costs for natural gas-fired resources thus keep ComEd capacity prices low.

Key Variable Definitions Across IRP Scenarios

Scenario Name	Load Case	EV Adoption Rates	Rooftop Solar Adoption Rates	Natural Gas Price Case	IMHR Case	ComEd Capacity Price Case	Technology Cost Trend
Reference	Base	Base	Base	Base	Base	Low	Base
High Market Price	Low	Low	High	High	Low	High	Faster Cost Reduction
Low Market Price	High	High	Low	Low	High	Low	Slower Cost Reduction

Calculating Batavia’s Cost to Serve Load

In addition to each resource’s standalone profitability, we calculated Batavia’s total cost to serve load using projected energy and capacity prices, which include three major components:

1. NIMPA Contract Costs

- Payments on Prairie State construction bonds and passed-through operations, maintenance, and fuel costs
- After Prairie State reduces output by 50% in 2038, the contract will charge Batavia for 27.5 MW of 24/7 replacement energy procured from the market

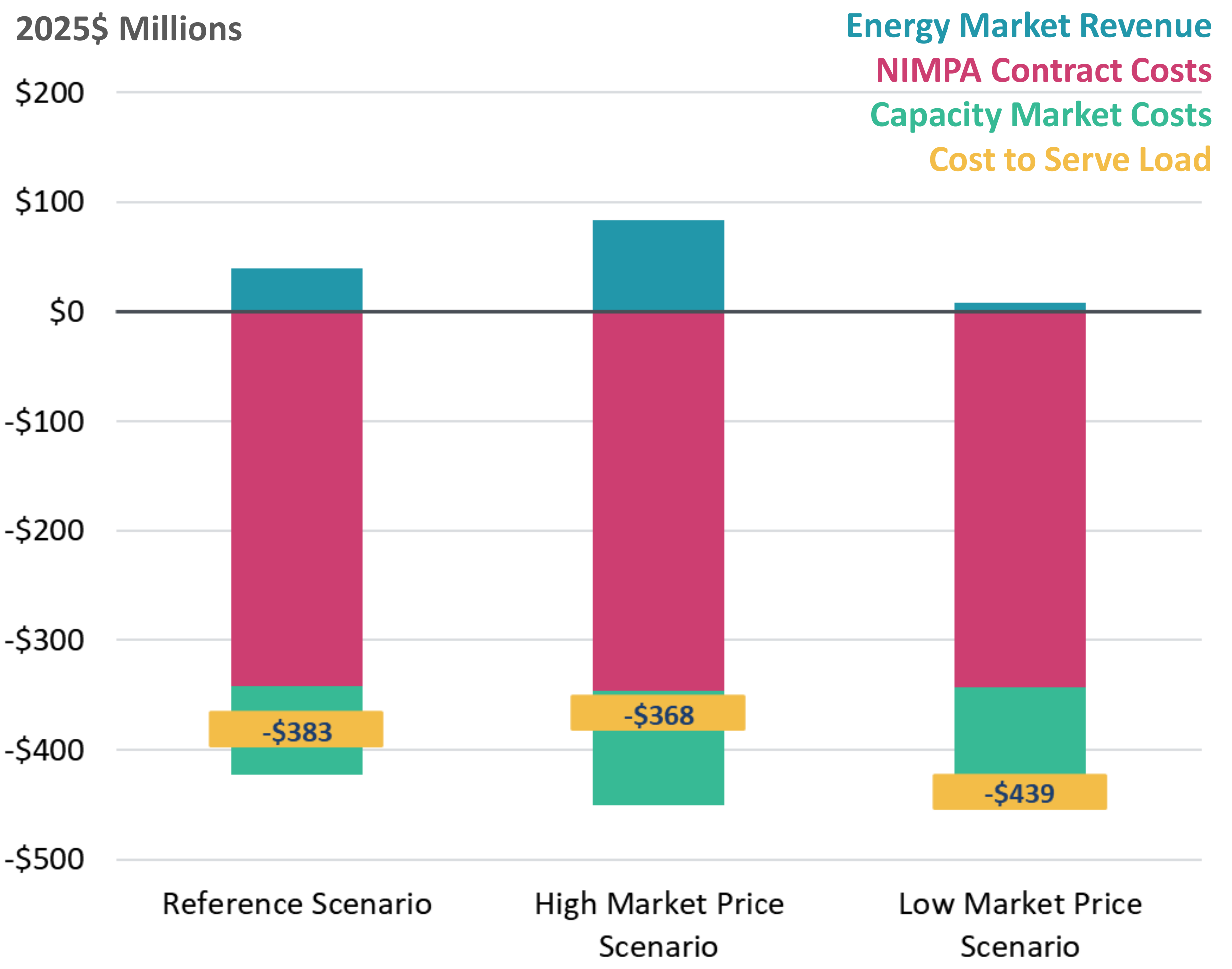
2. Energy Market Costs/Revenues

- Costs to procure energy to meet electricity demand, net of sales of energy provided by the NIMPA Contract

3. Capacity Market Costs

- Batavia procures its entire UCAP obligation from the capacity market, less the firm capacity guaranteed in the NIMPA contract.
- The NIMPA contract entitles Batavia to 55 MW of capacity, which NIMPA sells on its behalf. The profit is reflected in a discount on the energy price Batavia receives from NIMPA. This analysis captures that discount by decreasing Batavia’s UCAP obligation by 55 MW through 2038, and by 27.5 MW post-2038.

Present Value of Batavia’s Cost to Serve Load (2026-2045)



Preferred Portfolio: Costs and Revenues

We find that from an economic perspective, a RECIP could serve as the most cost-effective supply-side resource. Procuring such a resource earlier would yield more economic benefits to Batavia and customers.

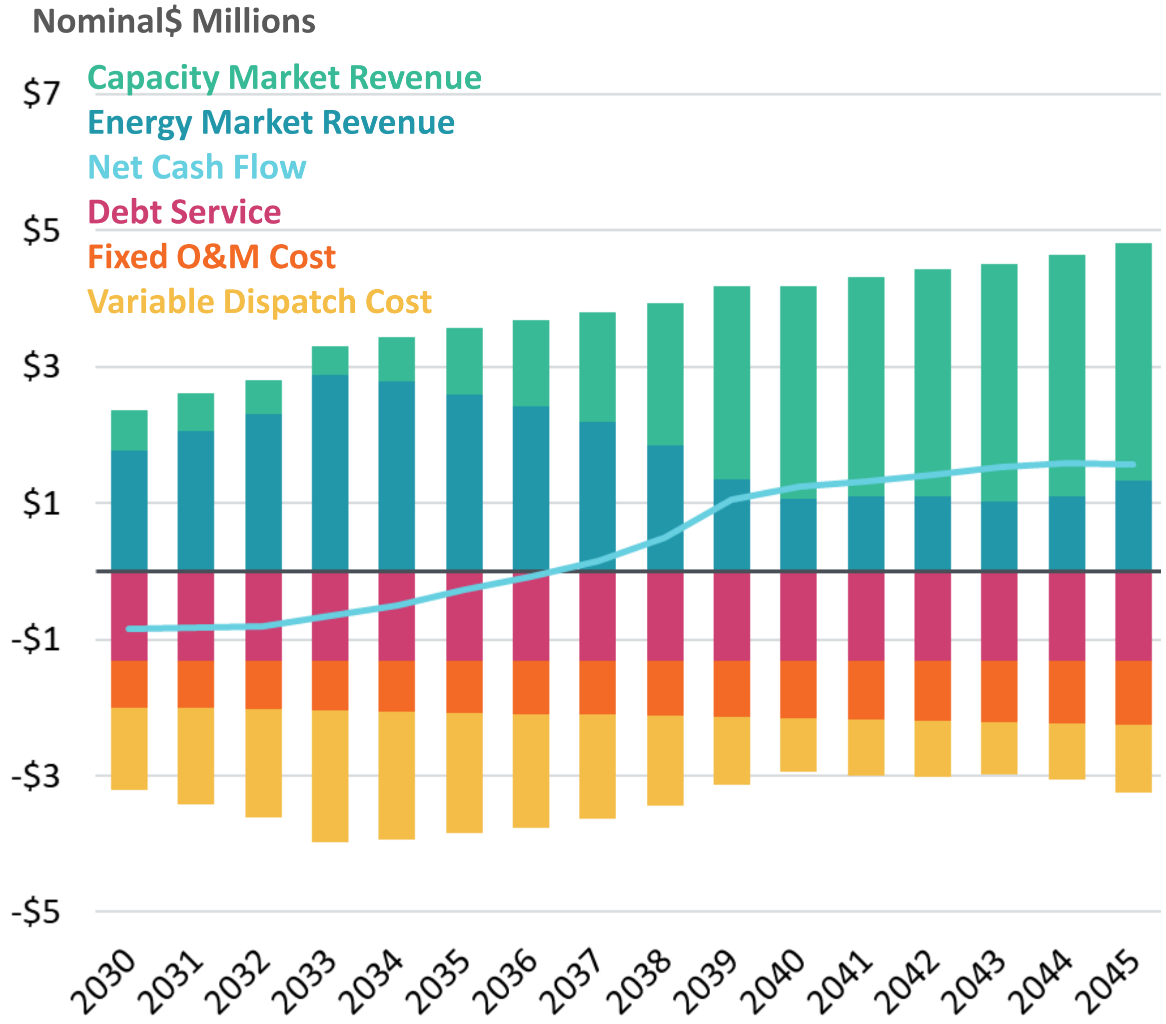
A RECIP would serve as a suitable hedge against Batavia's exposure to high energy and capacity prices.

- The RECIP bids into PJM's energy market when variable dispatch costs are below the market price. This caps Batavia's exposure to the highest market prices and earns revenue from selling excess generation.
- RECIP dispatch is typical of efficient peaking resources, with a capacity factor between 10-40% depending on the year and price levels.
- As a thermal resource, RECIP units have a high capacity value and can reliably earn payments from the PJM capacity market.
- If future ancillary service (AS) costs increase, RECIPs can participate in AS markets and earn extra revenue (not included in our modeling).

Post-2045, the RECIP can comply with CEJA by switching to a clean fuel like hydrogen and operating at a low (1-3%) capacity factor.

- This allows the RECIP to still claim capacity revenues, which can cover the RECIP's annual costs even without energy or AS revenues.
- Deploying a hydrogen-ready RECIP right now is prohibitively expensive due to the nascency of the technology.

Cash Flows for a RECIP With a 2030 Online Date (2030-2045)



Notes: Hydrogen-ready RECIPs offer future fuel-switching flexibility but face long-term risks, including uncertain hydrogen availability, high fuel and delivery costs, limited infrastructure, and evolving regulations. This report for NYSERDA expands on the considerations for hydrogen as a viable fuel to meet decarbonization goals for New York.

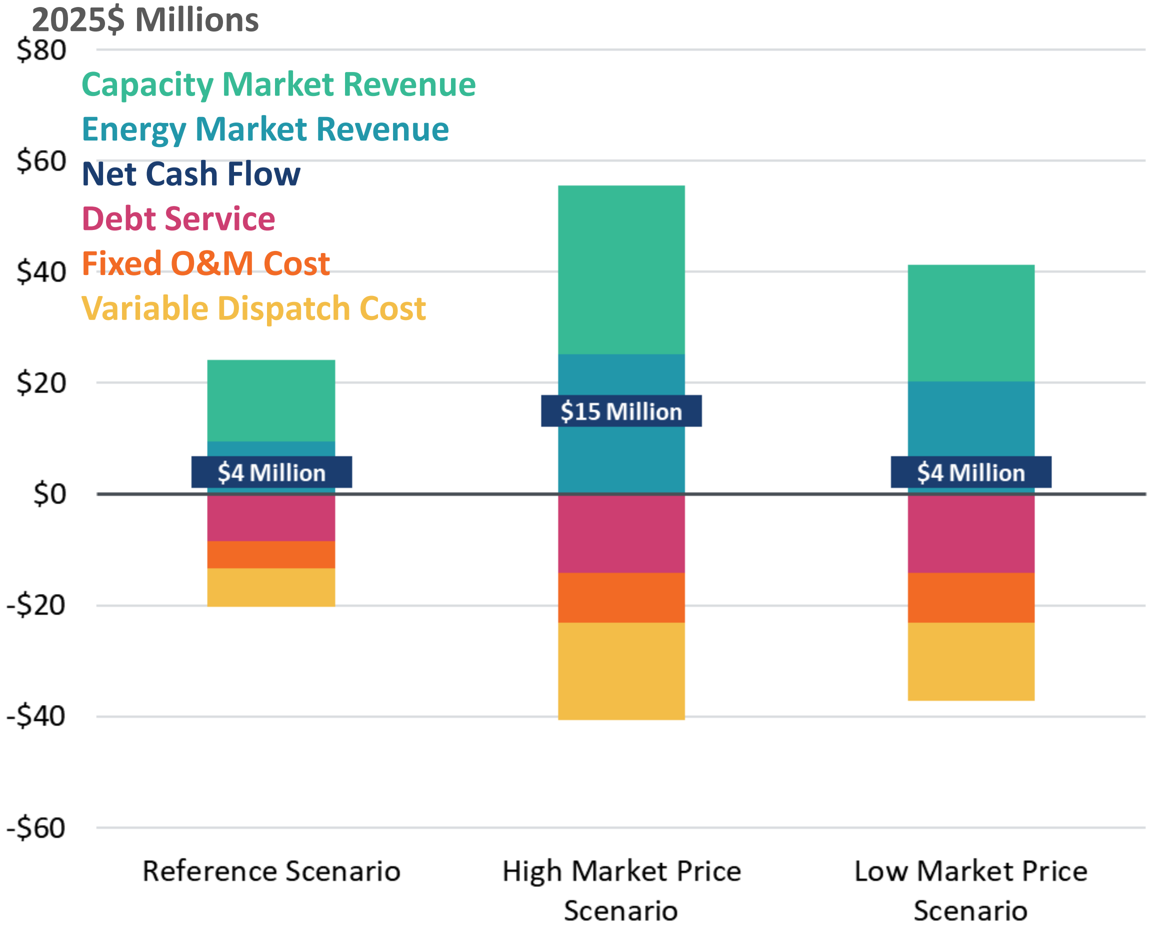
Preferred Portfolio: Scenario Testing

A RECIP should be deployed as early as possible to capture value from different potential market scenarios.

- We calculated the "optimal" deployment year for the RECIP in each scenario based on when the present value of its net revenues is highest.
- In the **Reference Scenario**, the RICE should be deployed in 2035 to avoid high gas prices and an increasing IMHR in the late 2020s and early 2030s.
- In both the **High Market Price** and **Low Market Price** scenarios, deploying the RECIP as early as possible (2028 is the earliest feasible year of deployment after accounting for training, permitting, and procurement lead time) maximizes the benefits for Batavia.
- An early deployment in the **High Market Price** scenario maximizes savings because the RECIP can take advantage of high energy prices and a decreasing IMHR in the late 2020s and early 2030s.
- In the **Low Market Price** scenario, an early deployment maximizes savings because the energy and gas prices remain stable while RECIP costs do not decline. Therefore, the earliest deployment possible maximizes total revenue without avoiding any high-price periods.

Given the RECIP's high capacity value, it has little downside risk and is profitable under all three scenarios, in large part because of the high projected PJM capacity prices.

NPV of RECIP Cash Flows (Optimal Online Year)



Notes: This IRP evaluates incremental renewable, storage, and demand-side resource pathways under a range of market scenarios that are directionally consistent with evolving decarbonization objectives under CEJA and Public Act 102-662. Long-term carbon-free portfolio configurations beyond 2045 were not explicitly modeled due to significant uncertainty regarding the future cost, availability, and operational characteristics of emerging clean fuel technologies, including hydrogen and other potential natural gas replacement fuels.

Cost Comparison among All Candidate Resources

We evaluated each resource under a series of sensitivities discussed more in the appendix. If the optimal online year is **2042 or later**, the resource is considered inviable because it cannot be deployed early enough to give Batavia a meaningful benefit.

Net Cost of Serving Batavia's Load (2026-2045, Base Case) – Optimal Online Year

2025$ thousands		Portfolio 1: Status Quo	Portfolio 2: 10MW BESS	Portfolio 3: 10MW Solar	Portfolio 4: 10MW Wind	Portfolio 5: 10MW Solar, 7.8MW BESS	Portfolio 6: 10MW RECIP
Optimal Online Date			2042	2045	2045	2042	2035
Resource Costs							
Capital Costs	[1]	$0	$2,654	$416	$749	$3,620	$8,446
Fixed O&M Costs	[2]	$0	$886	$116	$239	$807	$4,967
Dispatch Costs	[3]	$0	$555	$0	$0	$433	$6,782
Tax Credits	[4]	$0	$0	$0	$0	$0	$0
Total Resource Costs	**[5] = SUM([1]:[4])**	**$0**	**$4,095**	**$532**	**$987**	**$4,859**	**$20,195**
Resource Revenues							
Gross Energy Market Revenues	[6]	$0	-$1,649	-$451	-$648	-$3,091	-$9,488
Capacity Market Revenues	[7]	$0	-$2,597	-$64	-$241	-$2,299	-$14,733
Total Resource Revenues	**[8] = [6] + [7]**	**$0**	**-$4,246**	**-$515**	**-$890**	**-$5,390**	**-$24,221**
Load Costs							
NIMPA Costs	[9]	$342,153	$342,153	$342,153	$342,153	$342,153	$342,153
Energy Market Costs	[10]	-$39,705	-$39,705	-$39,705	-$39,705	-$39,705	-$39,705
Capacity Market Costs	[11]	$80,177	$80,177	$80,177	$80,177	$80,177	$80,177
Total Load Costs Net of NIMPA Contract	**[12] = [9] + [10] + [11]**	**$382,626**	**$382,626**	**$382,626**	**$382,626**	**$382,626**	**$382,626**
Net Cost of Serving Load	**[13] = [5] + [8] + [12]**	**$382,626**	**$382,475**	**$382,643**	**$382,724**	**$382,095**	**$378,601**
Savings from Portfolio 1			**$151**	**-$17**	**-$98**	**$531**	**$4,025**
Percent Difference from Portfolio 1			**0.0%**	**0.0%**	**0.0%**	**0.1%**	**1.1%**

Only the cost recovery from 2026-2045 is included

Notes: All figures shown are net present values over the period 2026-2045. Carrying costs during construction are capitalized. This analysis assumes that all resources are ineligible for federal tax credits including the PTC and ITC.

Evaluation of Alternative Resources

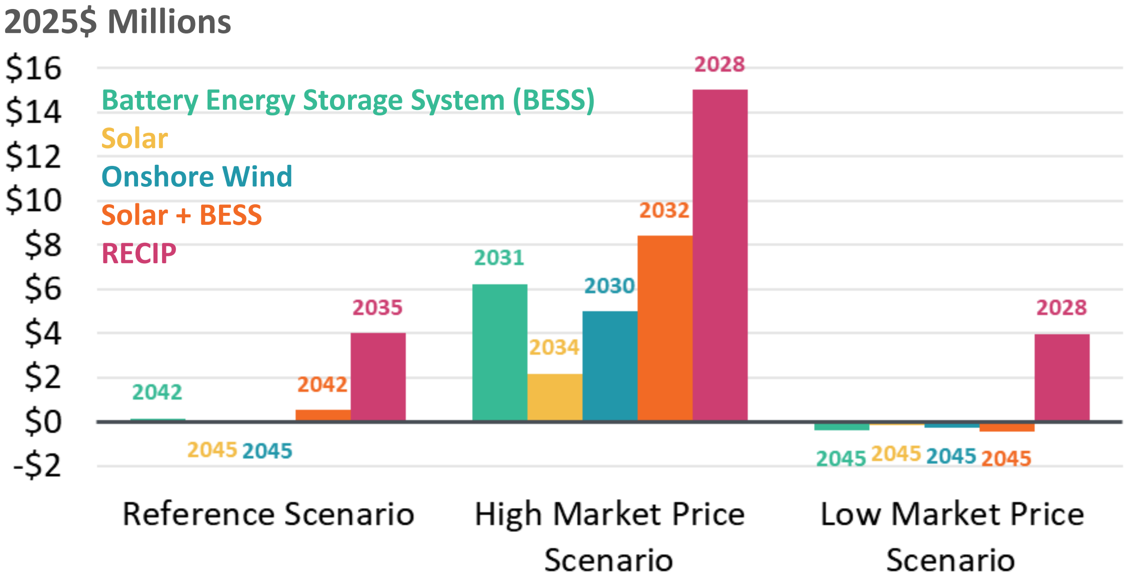
Our analysis indicates that all candidate resources except the RECIP carry some downside risk: they are unprofitable in at least one scenario.

Renewables are found to be not economically viable largely because of their low capacity value and lack of access to tax credit benefits that could improve economics.

- Because wind and solar resources are non-dispatchable, they have low capacity values and do not capture the same level of capacity payments from high capacity prices as the RECIP, making them less effective as hedges.
- While a BESS can be dispatchable, its costs are higher than those of the RECIP, and its profitability depends on the energy price volatility level.
- We assume that renewables are no longer eligible for investment and production tax credits under the Inflation Reduction Act
- BESS or Solar+BESS economics could benefit from the still-existing ITC but some technologies may not qualify due to new foreign entity of concern (FEOC) rules restricting the use of components purchased from China. Even if they receive the ITC, these resources are still less profitable than the RECIP.

All candidate resources could be profitable in at least one case, but the RECIP's *expected* profitability (assuming the **Reference Scenario** is most probable, with one of the other two scenarios being equally probable) remains the highest.

NPV of Resource Savings (Optimal Online Year)



Expected Value of Resource Savings (Optimal Online Year)

Optimal Online Date, 2025$ Millions	Reference Scenario [A]	High Market Price Scenario [B]	Low Market Price Scenario [C]	**Expected Value of Resource Savings [D]**
Portfolio 2: 10MW BESS	$0.2	$6.2	-$0.4	**$1.5**
Portfolio 3: 10MW Solar	$0.0	$2.2	-$0.2	**$0.5**
Portfolio 4: 10MW Wind	-$0.1	$5.0	-$0.3	**$1.1**
Portfolio 5: 10MW Solar, 7.8MW BESS	$0.5	$8.4	-$0.4	**$2.3**
Portfolio 6: 10MW RECIP	$4.0	$15.0	$4.0	**$6.8**

Notes: [D] = 50% x [A] + 25% x [B] + 25% x [C]. This analysis assumes that all resources are ineligible for federal tax credits including the PTC and ITC.

Summary of Supply-Side Analysis Results

Adding **a gas-fired RECIP** to Batavia's supply-side portfolio will allow the city to protect ratepayers from the rising costs of procuring capacity and energy

- A RECIP has a high capacity value, meaning that it can maximize the value Batavia can capture from rising capacity prices, and thus the reduction in total expected costs.
- The RECIP should be deployed as early as possible to maximize the value from potential short-term variations in gas, energy, and capacity prices (see five-year action plan on slide 85).
- If deployed in 2028, a 10MW RECIP could generate **between $4 and $15 million in savings** for Batavia's ratepayers through 2045.

Despite meaningful cost declines in recent years, **renewables and battery energy storage are not the most optimal supply-side resources to add today for Batavia**

- Renewables and storage have lower capacity values than RECIP and thus cannot offset higher capacity prices
- Without the Inflation Reduction Act tax credits, these resources will cost more and thereby not be able to meaningfully generate savings for Batavia during the study period
- Even if a battery storage system can qualify for the ITC, the RECIP still creates substantially more savings

In addition to supply-side resource procurement, Batavia can also reduce its cost to serve load by reducing demand through demand-side resources, which are discussed in the following section.

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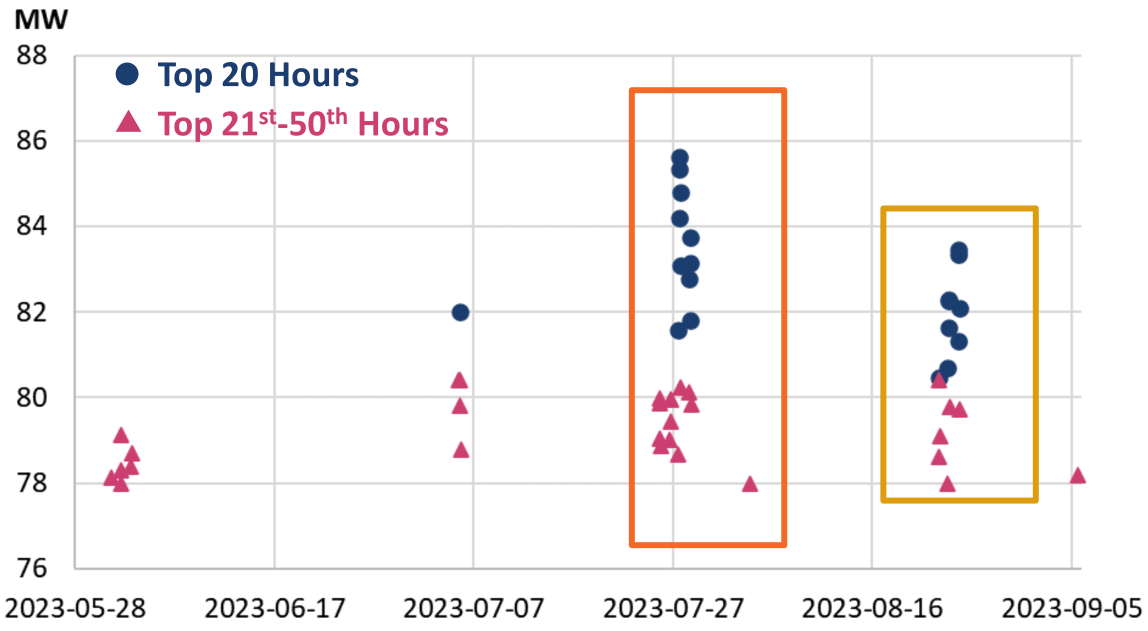
Batavia's Demand-Side Resource Potential

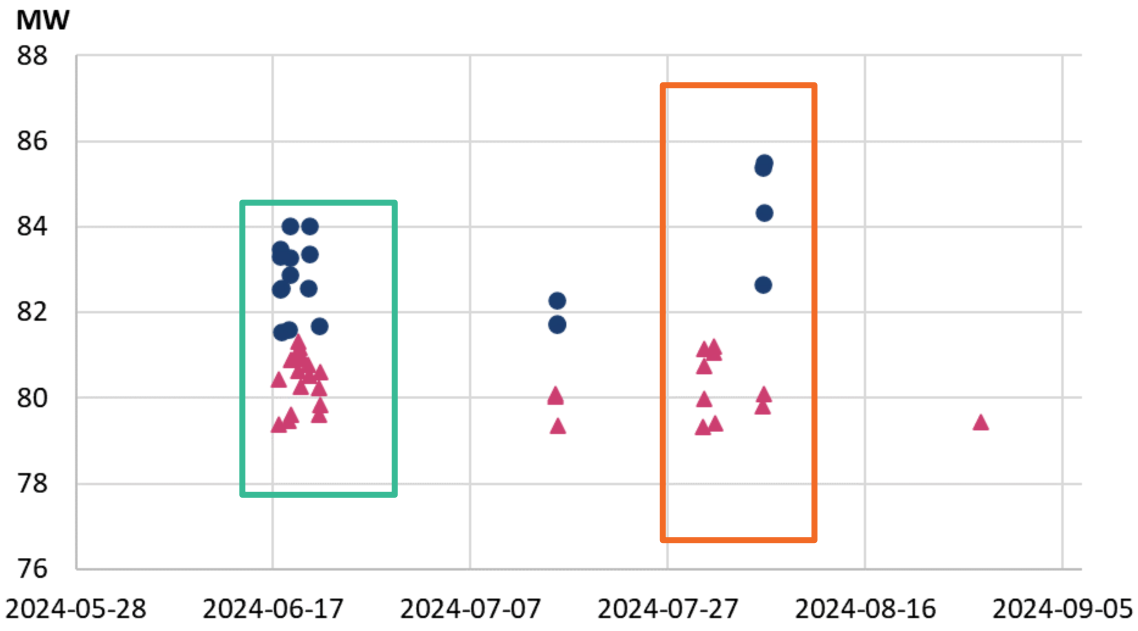
Demand-side resources (DSR) can reduce Batavia's exposure to market price risk, especially in the capacity market, by reducing or shifting the City's net peak load to lower-load periods. These reductions lower the City's obligation to procure capacity from the PJM market.

Many of the City's top 50 net load hours in both 2023 and 2024 occurred on summer weekdays between 3–6 PM, particularly in the last week of July (both years), late August (2023), and mid June (2024). The timing of these net loads suggests that programs designed to reduce customer demand during peak hours in the summer months could deliver system cost savings and reduce Batavia's exposure to high capacity prices.

Top 50 Net Load Hours in Batavia (2023)



Top 50 Net Load Hours in Batavia (2024)



Notes: Historically, Batavia has not operated formal utility-sponsored demand-side management or energy efficiency programs, as load reduction programs offered limited value under relatively low energy and capacity costs. However, with higher wholesale energy and capacity prices, this calculus has changed, making such programs more attractive. As a result, this IRP evaluates demand-side programs as potential future resource options under a range of market conditions.

Potential Demand-Side Resource Options

We identified a set of demand-side resource options that could be deployed in Batavia to shift or reduce load during peak periods.

Category	Program	Program Description
Heating/Cooling	HVAC Control	Customers enroll to allow smart thermostats to adjust cooling/heating setpoints during peak events. Utilities can deploy pre-cooling or setback strategies with limited disruption.
	Grid-Interactive Water Heating	Customers with electric water heaters participate in programs that enable load shifting through utility-issued control signals. Often part of broader grid-interactive appliance initiatives.
Electric Vehicle	EV Time of Use (TOU) Rates	Customers opt into a rate plan with higher prices during peak hours and lower prices off-peak. Designed to shift EV charging to nighttime or low-demand periods.
	EV Managed Charging	Utilities or aggregators control the timing of EV charging through smart chargers or vehicle telematics. Programs typically include incentives for participation and performance.
	EV Vehicle-to-Grid (V2G)	Participants allow their EVs to send power back to the grid during high-demand periods. V2G is often bundled with managed charging and requires bidirectional chargers.
Large Customers	Large Customer DR: Manual & Automated	Large C&I customers can reduce peak demand through manual or automated controls of HVAC, refrigeration, and other systems.
Others	BTM Battery Storage	Customers or utilities install behind the meter batteries that discharge during peak hours. Programs may include compensation or incentives and can be event-based or tariff-driven.
	Time-Varying Rates	Customers are placed on or opt into rates that vary by time or system conditions (e.g., TOU, Critical Peak Pricing). Programs encourage load shifting through price-based signals.
	Behavioral DR	Customers receive notifications to reduce usage during peak events but are not paid. These programs rely on behavioral nudges and are usually implemented as default opt-out.

Options for Batavia to Consider

We assessed the different demand-side options for their relevance to Batavia's system needs and their potential system benefit. This assessment is informed by our experience from other jurisdictions, along with the results from Batavia's customer survey.

We identified Residential HVAC Control (smart thermostats), EV TOU, EV Managed Charging, Residential and Small Commercial Time-Varying Rates, Manual and Automated Demand Response for Large Customers, and Battery Storage as highly applicable to Batavia. We did not explicitly model industrial DR because those programs are often designed specific to a given customer or utility.

Category	Program	Residential	Small C&I	Large C&I
Heating/Cooling	HVAC Control	High	Moderate	Moderate
	Grid-Interactive Water Heating	Moderate		
Electric Vehicle	EV TOU Rates	High	Moderate	Moderate
	EV Managed Charging	High	Moderate	Moderate
	EV Vehicle-to-Grid (V2G)	Low	Low	Low
Large Customers	Manual demand response			High
	Auto demand response			High
Others	BTM battery storage	Moderate	Moderate	High
	Time-varying rates	High	High	High
	Behavioral demand response	Low		
	Energy Efficiency	Moderate	Moderate	Moderate

Demand-Side Program Modeling Parameters

We modeled demand-side resource programs over the 2026–2045 planning horizon to estimate their energy and capacity savings for five programs. These programs are suitable to Batavia's system characteristics and customer preferences and have proven performance in other jurisdictions.

The benefits of each program to Batavia's system depends on its load impact type (load shifting or reduction), eligible custo mer base, assumed participation rate, and program design parameters.

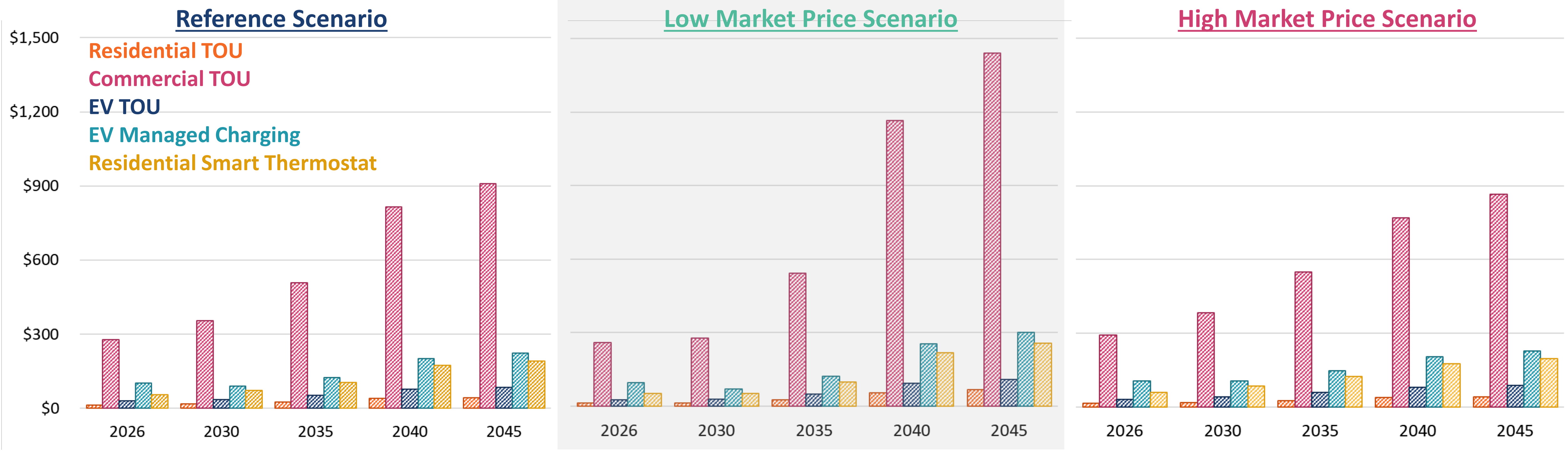
DSR Program	Customer Segment	Primary Grid Impact	Eligibility # of Customers (2030)	Per-customer Peak Reduction Impact (2030, kW)	Timing of program events
TOU Pricing	Residential	Load Shifting	10,020	0.1	Peak Period: Hour Beginning (HB) 15-18 (4-hour window)
	Commercial	Load Shifting	1,369	2.3	
EV TOU Pricing	EV Customer	Load Shifting	541	0.2	
EV Managed Charging	EV Customer	Load Shifting	541	0.6	150 events per year, with each lasting 4 hours
Smart Thermostat	Residential	Load Reduction	10,020	0.5	20 events in summer, each lasting 3 hours during peak periods (HB15 – 17)

Potential Demand-Side Resource Benefits

We find that potential DSR benefits are relatively stable across study scenarios, with the **Reference Case** capturing most of the program value, especially for high-performing options like **Commercial TOU**, **EV Managed Charging**, and **Smart Thermostats**.

- Per-customer benefits are driven by capacity savings and depend on total customer demand and the total savings enabled by each program.
- Of the resources studied, **Commercial TOU** programs enable the largest per-customer benefit because commercial demand is higher than residential demand. However, the lower number of commercial customers limits the total amount of achievable cost savings through this program option.

Benefit Modeling Results ($/Participant-Yr)



Prioritizing Demand-Side Resources to Develop

DSRs offer a flexible, quickly-deployable option to manage peak demand and defer infrastructure investment. However, their ability to offset long-term system growth depends on the scale of achievable load reductions, customer participation, and response rates. For reference, we estimated the number of participants that each of the five programs would need to achieve 1 MW of peak load reduction in 2030. The results suggest that Batavia may wish to prioritize DSR programs that have sizeable potential and scale quickly, such as Smart Thermostat and Time-Varying Rate programs. To prepare for broader deployment, Batavia may benefit from early investment in program design, customer engagement strategies, cost assessments, and system monitoring and billing software upgrades to enable technology readiness by the early 2030s.

Summary of Program Impact Potential

Program	Participants Needed For 1 MW of Load Reduction	Estimated Participants in Batavia in 2030	Batavia Potential in 2030 (vs 1-MW Battery)
Residential Time-Varying Rates	10,000	2,000	20%
Commercial Time-Varying Rates	435	137	31%
EV TOU	5,000	120	2.4%
EV Managed Charging	1,666	135	8%
Smart Thermostat	2,000	1,785	89%

Notes: $/kW program benefit is calculated by scaling the per-participant peak demand reduction potential to a comparable scale as a utility-scale battery. We calculate the estimated participants by applying % participation rate to the eligible customer base (residential, commercial, EV customer). Participation assumptions reflect estimated 2030 uptake rates: 20% of eligible residential and 10% of commercial customers for TOU Pricing; 22% for EV TOU Pricing; 25% for EV Managed Charging; and 28% for Smart Thermostat adoption among residential customers.

Summary of Demand-Side Resource Analysis Results

Demand-side resources have the potential to deliver value to Batavia's power system, primarily in the form of peak load reduction. They can also be scaled up quickly and provide customers options to manage their energy usage and bills. In the longer term, the value of DSRs will likely grow, driven by:

- Rising capacity and energy prices, particularly during high-demand periods;
- Increased deployment of renewable resources, which introduces greater variability in hourly prices; and
- The need for flexible demand to help stabilize the grid and hedge against extreme price events.

We also note that the current analysis does not include distribution-level benefits, such as deferred upgrades or local reliability improvements. These benefits may be addressed separately in an infrastructure-focused study and could further strengthen the case for DSR investment.

Although we did not model large customer DSR in this analysis, several industry studies have shown that targeting commercial and industrial customers can deliver significant system value through peak load reduction and improved grid flexibility. We recommend that Batavia explore these opportunities as part of its broader DSR strategy.

To unlock and realize the potential value of demand-side sources, the City will need to build out a new DSR program, which may require new forms of customer engagement, system integration, and program administration. Batavia will also need to make new investments in program management platforms, customer enrollment systems, marketing and outreach, and potentially new staffing.

To manage implementation costs and maximize impact, Batavia could consider a portfolio approach, where several DSR programs are deployed together to spread startup costs around and increase each one's benefit-cost ratio. For example, the residential smart thermostat program and a time-varying rate program targeting large commercial customers can be deployed around the same time to achieve the highest system value in the near term and serve as practical entry points for broader DSR adoption in the future.

IRA Programs – Application Status

While the IRP primarily evaluates supply-side resource options, Batavia also recognizes the importance of longer-term demand-side strategies to help manage future load growth, peak demand, affordability, and CEJA-related planning objectives. The IRP findings suggest that supply-side resources alone may not fully address Batavia's long-term planning priorities. As a result, Batavia is also actively exploring demand-side strategies as part of a broader long-term planning approach.

Consistent with that direction, Batavia has applied for funding under the Illinois Climate Pollution Reduction Grant (CPRG) Small Utility Clean Energy Planning Grant, a federally funded program under the Inflation Reduction Act (IRA) . The application was submitted in April 2026 and is currently under review. Batavia has requested $200,000 in grant funding (no local cost share required) to support near-term planning efforts. The proposed work spans 2026–2028 and is focused on advancing demand-side resources identified in this IRP. The grant is competitive and subject to award by the State.

Application scope includes:

- Development of demand-side management (DSM) programs and implementation roadmap
- Evaluation of load reduction, load shifting, and EV-related programs
- Planning activities to support emissions reduction and CEJA-aligned objectives
- Capacity-building for program design, procurement readiness, and performance tracking

The proposed funding supports planning and program development only and does not provide capital funding for resource deployment. Any awarded funds would be subject to applicable state and federal reporting and compliance requirements.

Batavia has not received or utilized IRA grants, loans, or tax benefits to date. As a result, this IRP evaluates resource options without reliance on federal tax credits or incentives as a conservative planning approach. Going forward, Batavia will continue to monitor and pursue IRA-related funding opportunities to support implementation of demand-side programs and other resource strategies identified in this IRP.

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Five-Year Action Plan Timeline

We recommend that Batavia focus on building its capacity to respond to emerging market and policy conditions over the next five years.

	Year 1	Year 2	Year 3	Year 4	Year 5
Market/Policy Monitoring	Throughout this period, City should continue monitoring market and policy developments, including energy and capacity prices, resource costs, tax credit policy, environmental regulations, and programs, grants, loans, or tax benefits that are potentially available to help support resource procurement. Update economic analysis of different resource options as appropriate.				
System Upgrades	Evaluate hardware and software upgrades needed to support supply- and demand-side resources and incoming data center.	Initiate procurement of hardware and software upgrades enabling demand-side programs			Evaluate upgrading system information and control technologies to automate demand-side program calls through DERMS.
Supply-Side Resources	Issue RFIs for supply-side resources, focusing on RECIP procurement. Work toward policy consensus on supply- and demand-side resources with City stakeholders.	Initiate limited procurement of supply-side resources (e.g., 1-5 MW RECIP) to gain operational and market participation experience. Consider renewables or storage procurement, costs permitting.	Complete any necessary interconnection, testing, and initialization procedures for supply-side resource. Begin operating resource in PJM energy and capacity markets.		Evaluate procurement of additional supply-side resources based on experience with trial resource, market price evolution, policy developments, demand growth, and other factors.
Demand-Side Resources	Initiate outreach campaign to recruit demand-side program participants, focusing on industrial customers.	Pilot demand-side programs with manual event calls, focusing on C&I customers. Review initial demand-side program data and survey participants to evaluate program effectiveness, participation patterns, and potential program improvements.	Continue gaining experience with demand-side program participation. Continue outreach efforts to socialize programs and increase participation.		Evaluate adjustments to demand-side program portfolio based on load growth, customer participation, and program costs.

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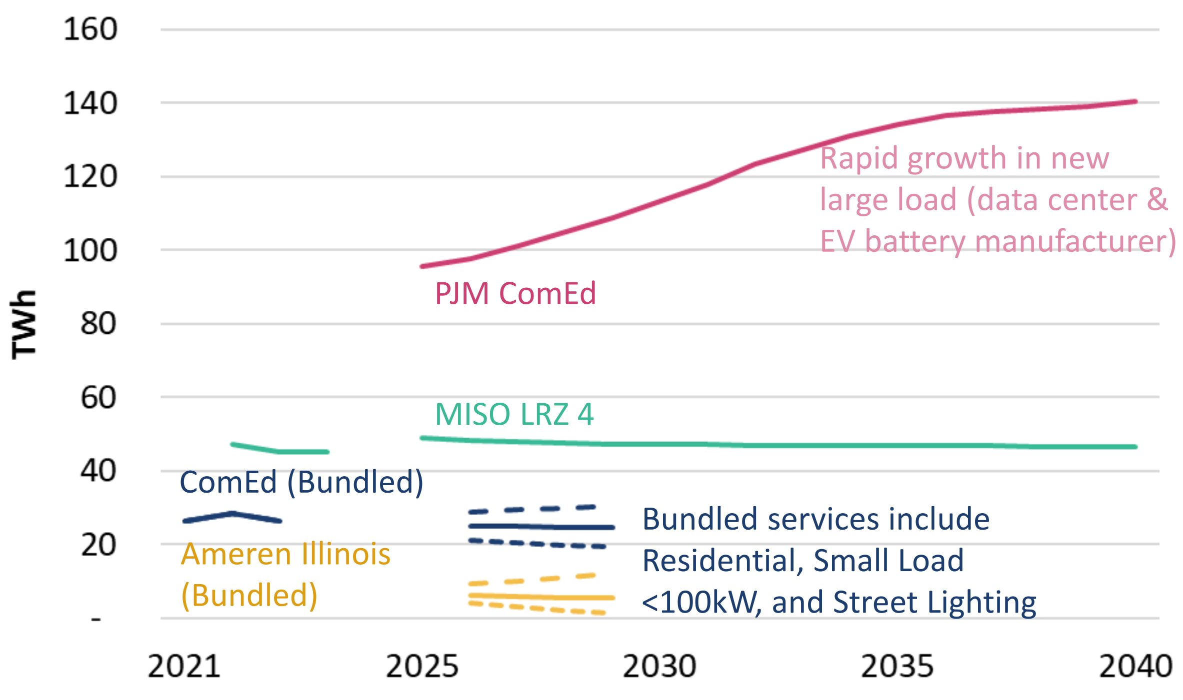
Appendix A: Load Scenarios

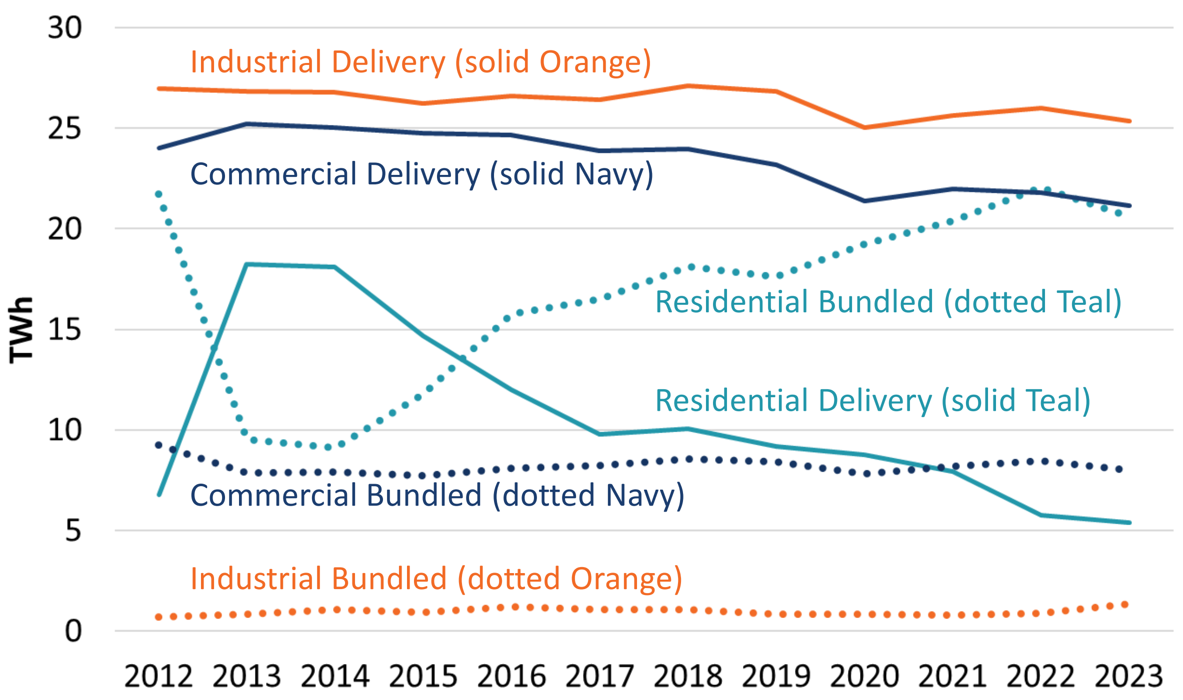
Load forecasts in neighboring jurisdictions

To understand neighboring jurisdictions' expectations for load growth, we reviewed historical and forecasted energy consumption data from MISO and PJM's long-term load reports, as well as load forecasts from ComEd and Ameren IL. Similar to Batavia, neighboring jurisdictions have seen largely flat historical load. Outside of select growth in ComEd due to new large load sources, neighboring jurisdictions forecast flat load in the coming decades.

Historical and Forecasted Sales



ComEd Historical Sales (by Customer Class)



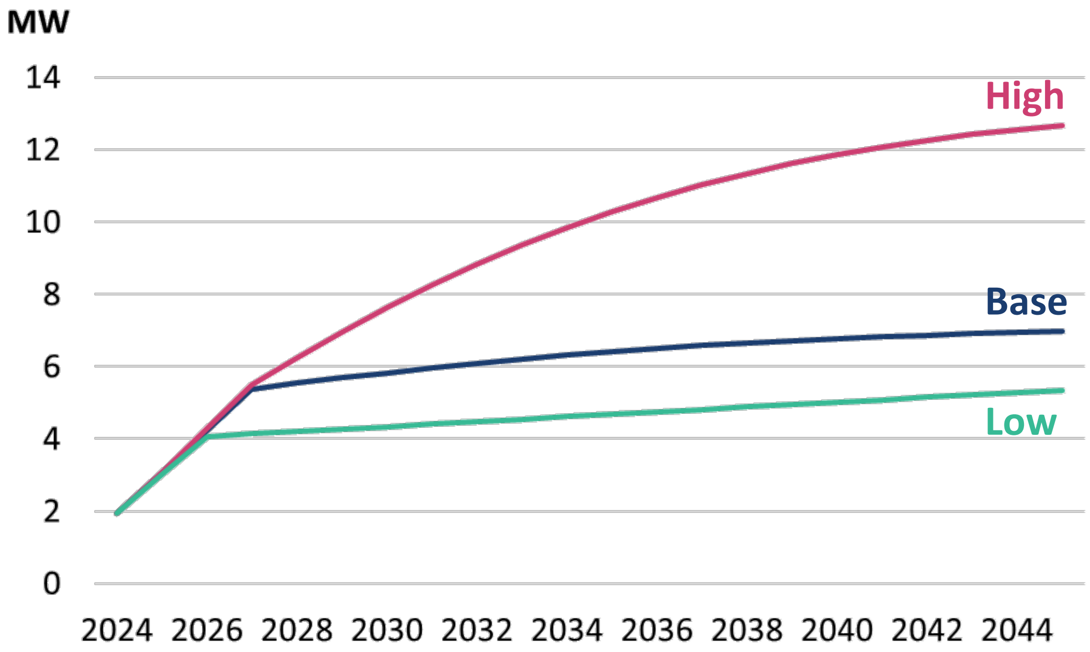
Distributed Solar Forecast – Base Subcase Methodology

We employ a multi-step process to forecast the increase in distributed solar capacity (and subsequent hourly contributions to load) in Batavia. The steps below detail the derivation of the **Base** solar subcase estimate:

- We start with ComEd's 5-year load forecast for eligible retail customers, which includes separate estimates of distributed solar generation by residential and Commercial & Industrial (C&I) customer classes
- We extend the ComEd forecasts from 2030 to 2045 using an extrapolated fit and use this data to calculate annual solar generation growth rates
- We apply these growth rates to Batavia data on distributed solar installed capacity by customer class to produce estimates of annual solar installed capacity by year. We also account for 3 MW of planned distributed solar additions by industrial customers by 2027 (1 MW/year, starting in 2025)
  - While the ComEd data provides an estimate of growth in solar generation (in MWh), we are comfortable applying these growth rates to solar installed capacity (in MW) because a separate PJM distributed solar forecast predicts little change in distributed solar capacity factor between present and the end of the study period
- Estimates of annual solar installed capacity by year are converted into hourly data on solar contribution to load using class-specific generation profiles from NREL PVWatts tailored to the Batavia location

See the following slide for additional detail on the calculation of the **Low** and **High** solar subcases, which use alternative solar growth rates derived from historical growth in distributed solar in Batavia across different time periods

Batavia Distributed Solar Installed Capacity Forecast

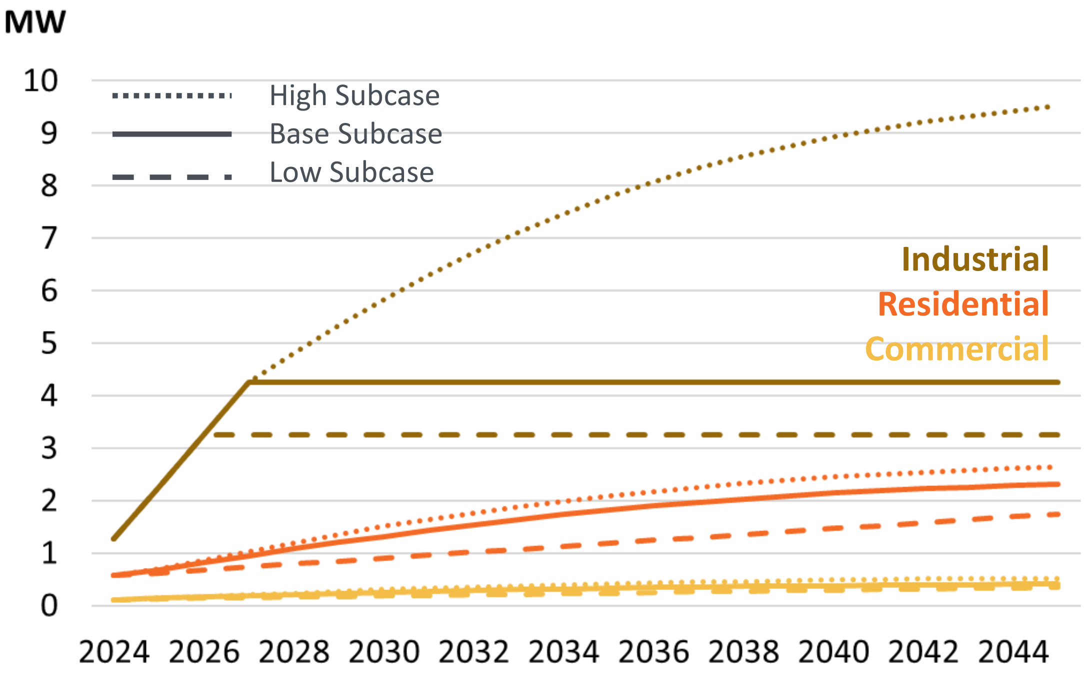


Source: 2024 solar installed capacity and gross load calculated using net load and distributed solar installed capacity data from Batavia.

Distributed Solar Forecast Buildup

Subcase	Description
Base Solar	• **Residential; Commercial:** growth projections from ComEd 5-yr. forecast of distributed solar adoption • **Industrial:** Assumes 1 MW/yr of solar additions from 2025 – 2027 (3 MW total), then no additions thereafter • Total installed capacity by 2045: 7.0 MW
High Solar	• **Residential; Commercial:** Growth until 2030 based on Batavia's post-pandemic residential solar growth (in % terms); growth thereafter matches Reference case • **Industrial:** Same assumptions of near-term solar additions as Reference case, plus additional growth beyond 2027 using growth rates from ComEd 5-yr. forecast • Total installed capacity by 2045: 12.7 MW
Low Solar	• **Residential; Commercial:** class-specific kW/yr growth projections based on Batavia historical solar additions since 2014 • **Industrial:** Same as Reference but no additions in 2027 (i.e., 2 MW total) • Total installed capacity by 2045: 5.4 MW

Distributed Solar Installed Capacity by Subcase and Customer Class



Source: 2024 values based on historical capacity of distributed solar provided by Batavia. See table at right for description of projections.

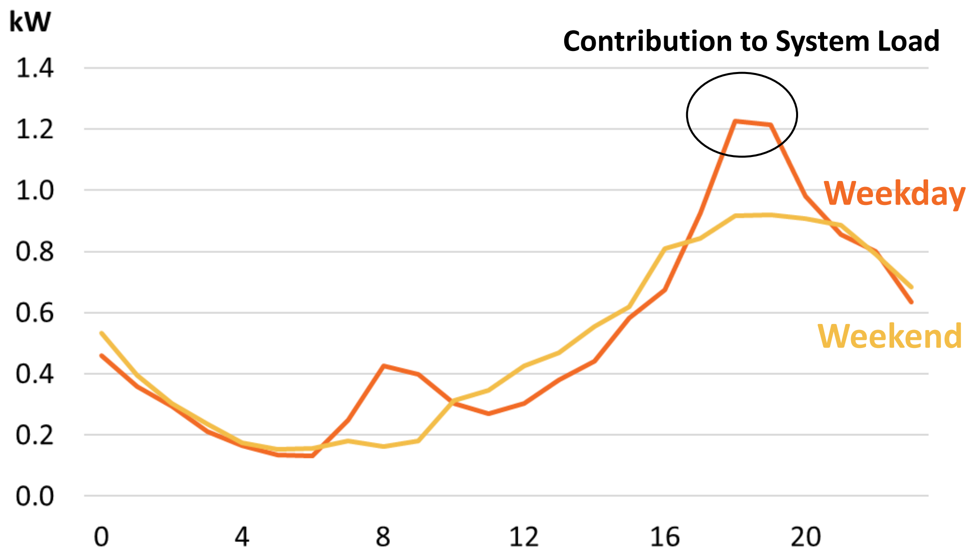
EV Forecast

	Description
Reference EV Case	• PJM ComEd Annual Load Growth (equivalent to 15% EV adoption by 2045) • EV share by 2030: 3%
High EV Case	• Batavia reaching 25% EV adoption by 2045 • EV share by 2030: 5%
Low EV Case	• Batavia reaching 10% EV adoption by 2045 • EV share by 2030: 2%

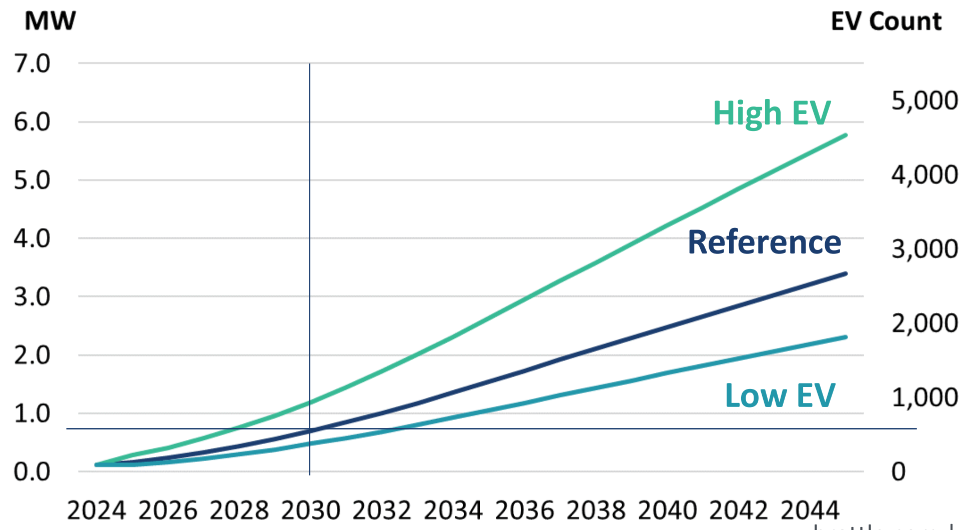
Notes and Sources:

1) EV Charging profiles for all three cases are modeled from NREL's Electric Vehicle Infrastructure (EVI) Toolbox. The base load profile are modeled for Danville, IL and assume each electric vehicle travels 35 miles per day. Of the plug-in vehicles, we assume 75% are fully electric and 25% are hybrid. Workplace charging is assumed to be a mix of 20% Level 1 and 80% Level 2. All vehicles have access to home charging, split evenly between Level 1 and Level 2 (50%/50%). Additionally, it is assumed that 100% of customers prefer home charging and choose to charge as quickly as possible.
2) EV efficiency is assumed to be the average of midsize cars at 3.2 miles per kWh based on DOE Vehicle Technologies Office Factsheet.
3) Batavia's vehicle counts are calculated based on CMAP data for Vehicles Available per Household from 2018–2022. For households reported to have three or more vehicles, we assume a total of three vehicles. No vehicle growth is assumed through 2045.
4) We assume the load profile stays the same through 2045.

Modeled Charging Profile per EV (kW)



EV Contribution to System Load (MW)

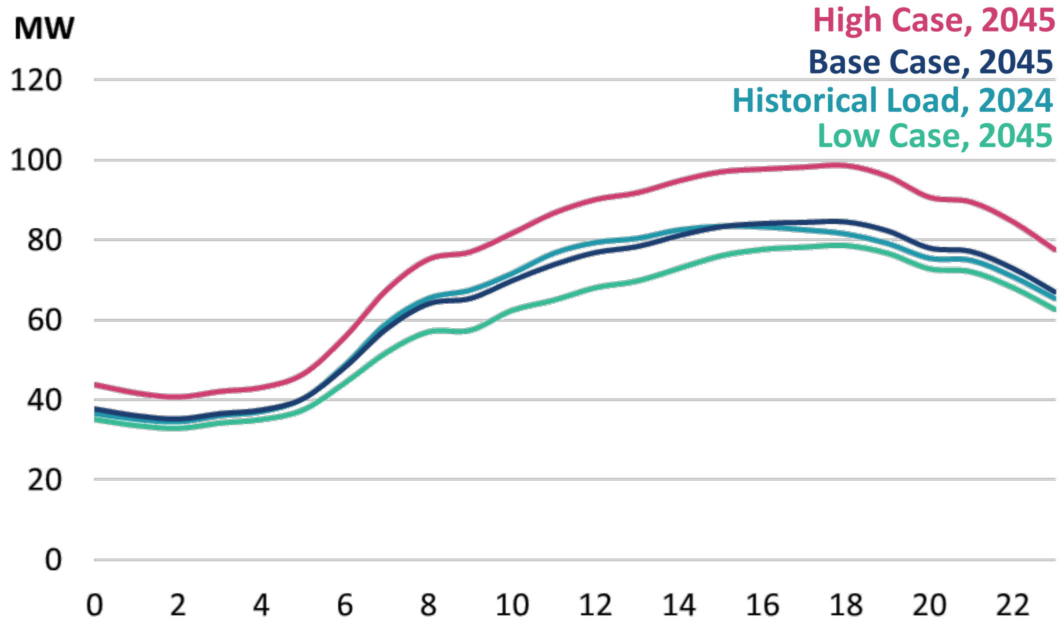


Projected Net System Load: 24 Hour Profile

Under all cases, Batavia's net load shape is not expected to change drastically between present and the end of the study period, despite projected increases in distributed solar and EV penetration

For example, on June 17th, the day of the net peak load in 2045, the 2045 load shape remains largely unchanged compared to the 2024 profile, despite increases in distributed solar installed capacity and EV charging load

Batavia Net Load Forecast, Day of 2045 Net Peak
(MW; June 17th Only)

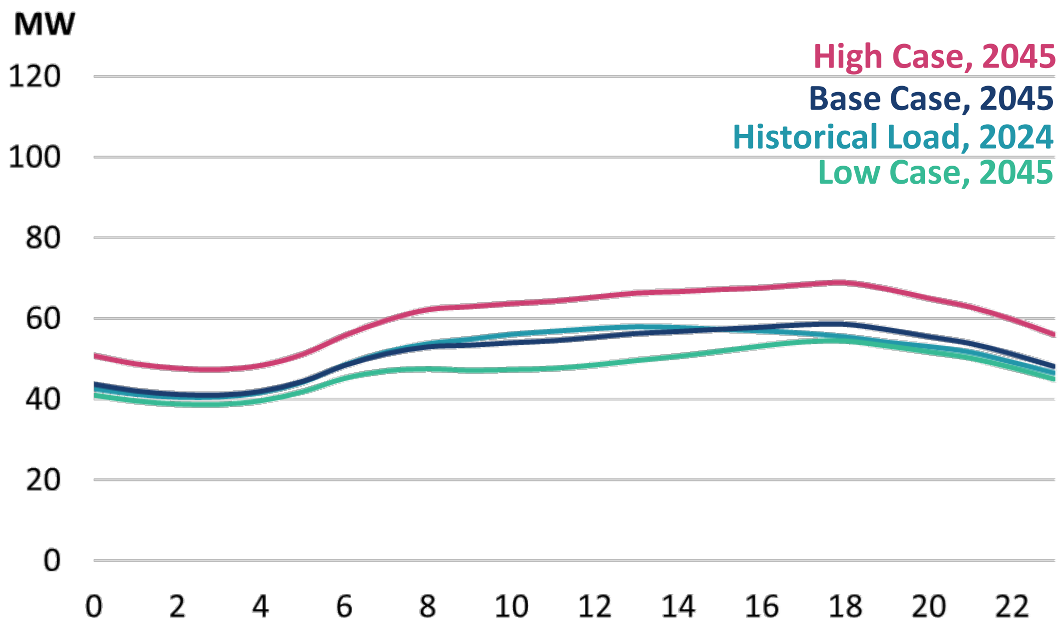


Notes: June 17th selected for graphing because the Base case modeling of this day features the net peak load in 2045, which occurs at hour beginning 6 PM.

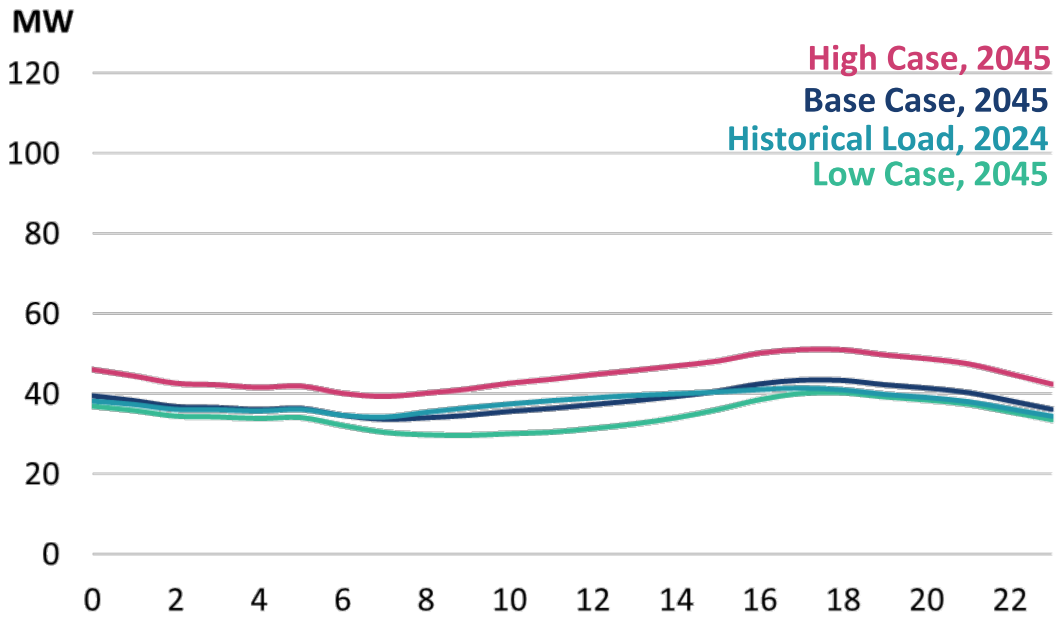
Projected Net System Load: 24 Hour Profile

Both weekend and weekday load shapes are not expected to change significantly between the present and the end of the study period

Batavia Net Load Forecast, Annual Avg by Hour
(MW; Weekday Only)



Batavia Net Load Forecast, Annual Avg by Hour
(MW; Weekend Only)

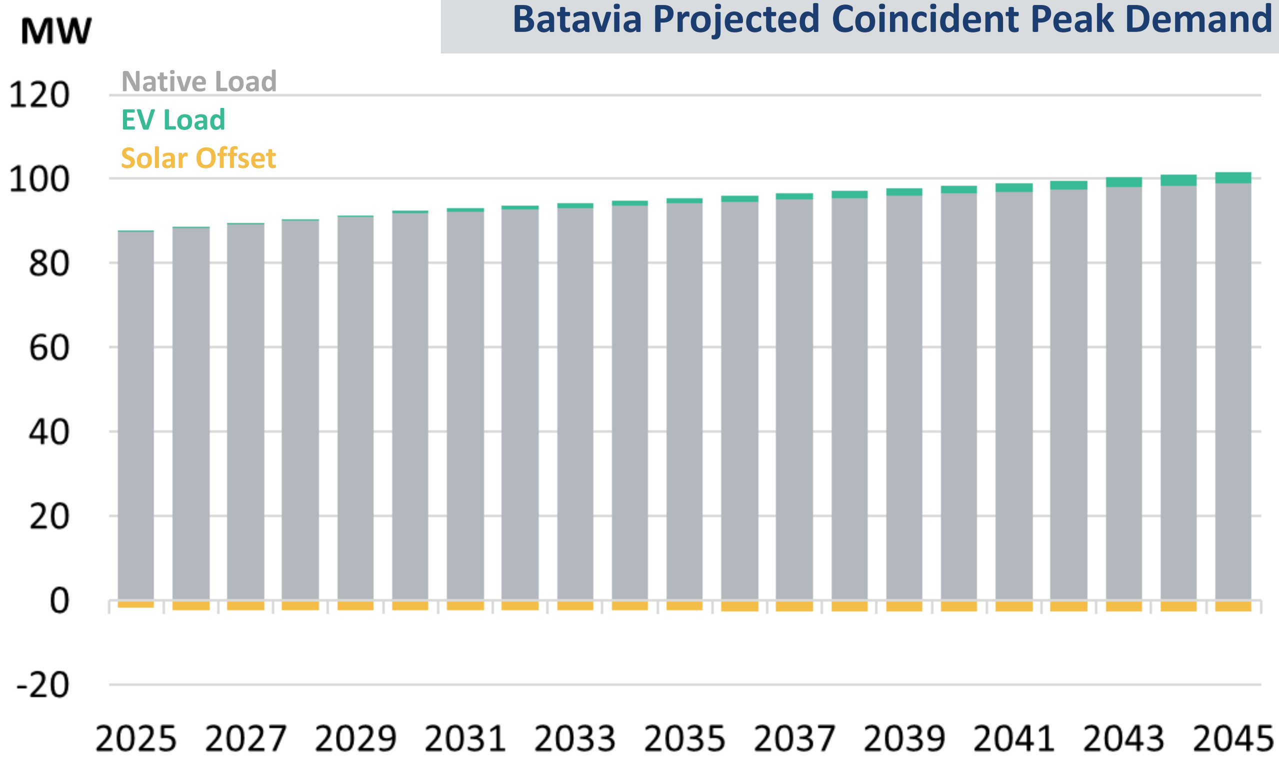


Notes: 2024 load data provided by Batavia. Data reflects the average hourly net load across all weekday dates (left) and all weekend dates (right), grouped by year.

Growth Forecasts by Load Driver

Projected peak demand growth is driven primarily by underlying customer load growth and increasing electrification, including electric vehicle adoption. Distributed solar adoption partially offsets future peak demand growth, though total coincident peak demand is still projected to increase under the Base and High growth scenarios over the planning horizon. Under the **High Case**, stronger economic growth, electrification, and large customer demand contribute to higher future peak demand levels, with coincident system peak demand approaching 99 MW by 2045.

Batavia Projected Coincident Peak Demand by Load Driver (MW; High Case)



Year	Native Load	EV Load	Solar Offset	Net Load
2025	87.4	0.1	-1.6	85.9
2030	91.8	0.5	-2.3	90.1
2035	94.1	1.2	-2.4	92.9
2040	96.5	1.9	-2.6	95.8
2045	99.0	2.6	-2.7	98.8

Appendix B: Capacity Price Separation

Transmission and Local Capacity Needs For Reliability

PJM LDAs meet their reliability requirements with local resources and firm capacity imports.

Importing capacity is often cheaper than building local supply, but only if transmission is available.

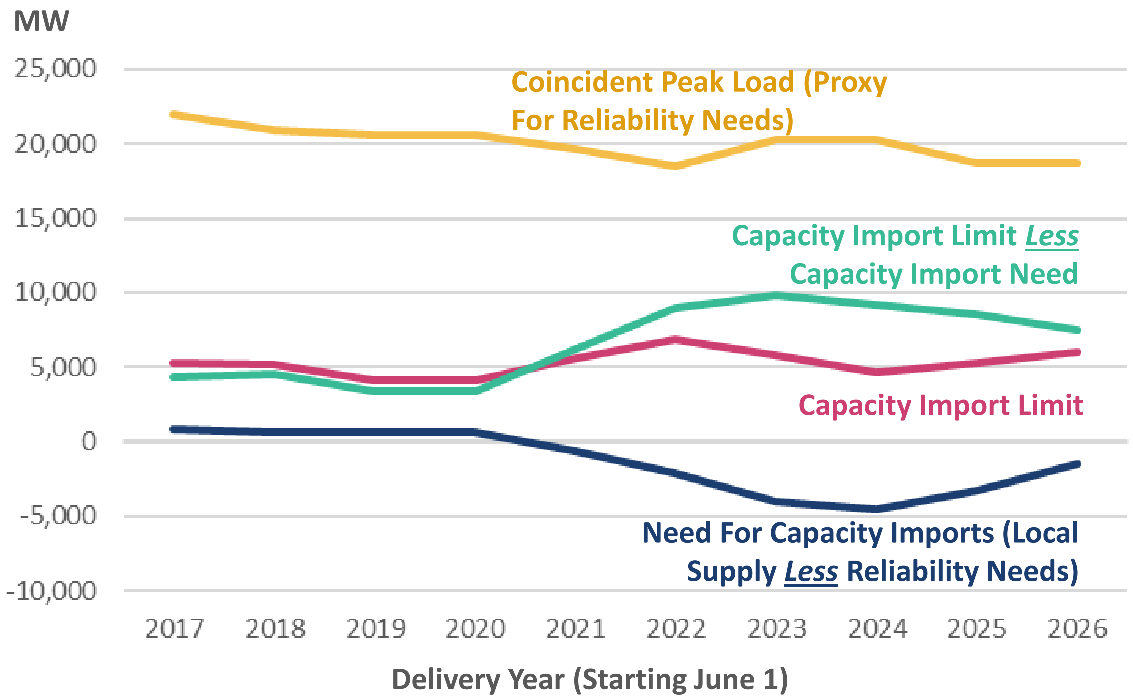
- If there is not enough transmission to meet local reliability needs, an LDA's capacity price increases to attract new resource builds.

ComEd has not been import-constrained historically, nor is it expected to be in the future.

- ComEd's import capability has exceeded its needs by **6-10 GW** since PJM increased its import limit to 5.5 GW in 2021.
- 4 GW projected load growth by 2045 and 1.1 GW coal retirements by 2030 fall within ComEd's import cushion.

We do not expect import capacity limits to drive ComEd capacity prices above the RTO-wide level.

ComEd Capacity Needs And Import Limit



Source: PJM BRA Planning parameters.

ComEd Capacity Price Separation

Capacity prices are set by the cheapest option to meet reliability needs.

Economic constraints can cause price separation, even if there is ample import capability.

- Expensive local resources can set an LDA's capacity price, even if imports are not strictly needed for reliability.
- ComEd prices were higher than PJM from 2017–2022 due to local resource costs, not import limitations.

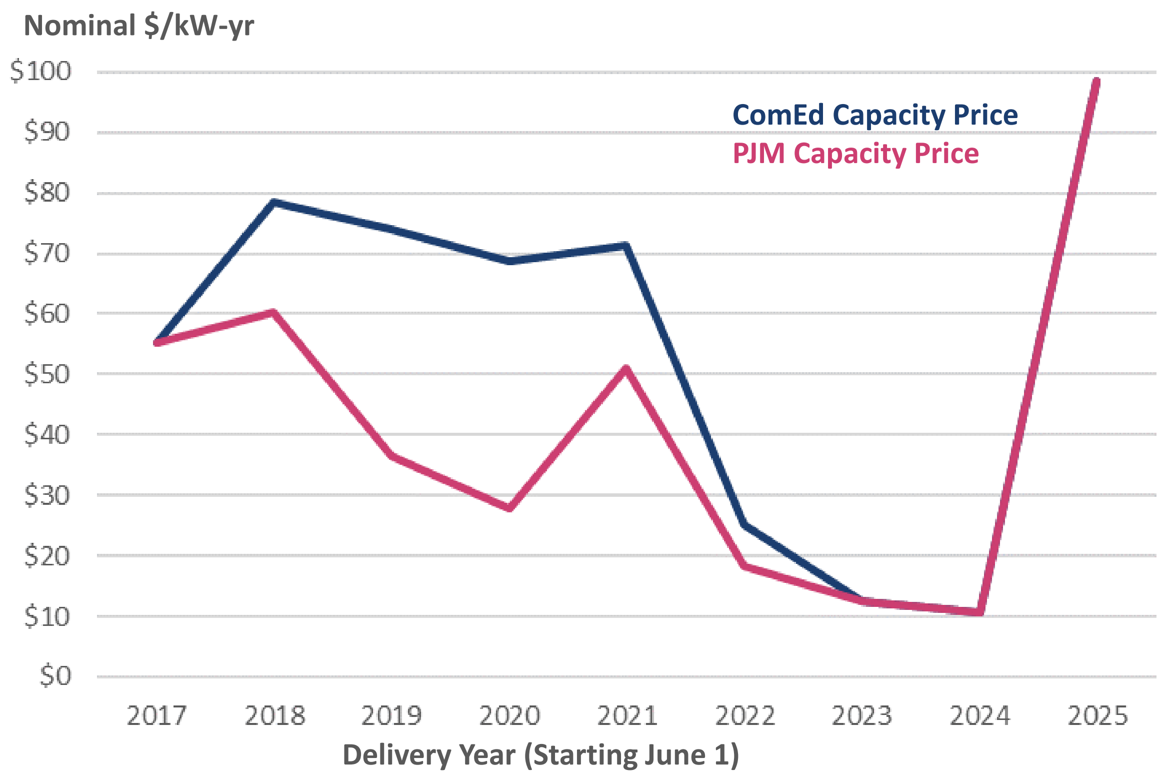
Price separation disappeared from 2023 onward, likely due to policy shifts lowering the cost of existing local resources.

- CEJA included subsidies for 6.5 GW of nuclear resources.

ComEd prices may separate again in the future if changes in subsidies or market rules result in higher local resource costs.

- ComEd's net CONE remains higher than RTO-average.
- Brattle's most recent PJM Net CONE Study (April 2025) suggests a 40% higher CC net CONE in the ComEd LDA in 2028.

Historical PJM Capacity Auction Clearing Prices



Appendix C: Potential Changes to the PJM Capacity Market

Potential Changes to PJM Capacity Market Rules

PJM has started considering changing the current capacity market constructs. PJM put forward three possible paths, from long-term bilateral contracting with a spot capacity market to ERCOT type energy scarcity market approach. The industry generally views this change as more of a risk for IPPs.

- PJM's stakeholder discussions are focused on ensuring long-term resource adequacy while addressing concerns regarding affordability and investment incentives.
- While PJM has outlined several potential market structures, no final market design has been selected and stakeholder discussions remain ongoing.
- Regardless of the capacity price construct, the fundamentals remain the same – the market has to pay for the long-run costs of generation.
- Resources must ultimately recover sufficient revenues to support investment, whether through capacity payments, energy market revenues, ancillary service revenues, bilateral contracts, or some combination thereof.
- While the split between capacity and energy-associated payments may change, the total amount load serving entities will need to pay should not vary materially by construct.
- Different market designs may shift how costs are collected and allocated among market participants, but they do not eliminate the underlying costs required to maintain a reliable electric system

Therefore, this IRP does not speculate on the potential impact of the PJM capacity market restructuring.

Sources: Powering Reliability Through Market Design, May 2026.

Appendix D: Supply-Side Resource Cost Assumptions

Capital Cost Adjustments For Supply-Side Resources

When analyzing the potential revenues and costs for each selected generation technology, we will refine national estimates ofcapital cost using location-specific capital cost multipliers.

The multipliers below are published by EIA and vary by location and technology type, based on applicable labor costs, environmental conditions, and regulations.

Capital Cost Multipliers – Chicago, IL

Resource	Locational Adjustment (Capital Cost Multiplier)
Standalone Solar	1.13
Standalone Wind	1.20
Solar + Storage	1.12
Battery Storage	1.07
Natural Gas RECIP*	1.22

Sources and notes: *Gas RECIP plant uses the multiplier for a natural gas combined cycle plant, because EIA does not publish RECIP-specific data. All cost multipliers are produced by EIA for Chicago region (only city for which there are estimates in IL). See EIA, Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies, 2024.

Appendix E: Demand-Side Resource Results

DSR program results

We find that all five modeled DSR programs provide increasing value over time, with variation in savings magnitude by program type:

- Residential Smart Thermostats consistently deliver the highest per-customer savings, reaching $192 by 2045, and generate the largest system-wide potential at $345k by 2045.
- Commercial TOU provides strong performance, especially in early years, with per-customer savings rising to $910 in 2045.
- EV Managed Charging and EV TOU programs show steady growth, with per-customer savings for EV Managed Charging reaching $227 and total potential exceeding $128k by 2045.
- Residential TOU, while lower in per-customer value, will scale meaningfully with broad participation.
- Across all programs, capacity savings per customer account for the majority of total benefits, particularly for TOU and smart thermostat programs.

Summary of Per Customer Savings and Total Savings by Year, Reference Scenario ($)

Program	Metric	2026	2030	2035	2040	2045
Energy Savings per Customer	Residential TOU	$1	$1	$2	$1	$1
	Commercial TOU	$28	$25	$34	$26	$30
	EV TOU	$8	$7	$10	$7	$8
	EV Managed Charging	$38	$8	$7	$3	$2
	Residential Smart Thermostat	$2	$2	$3	$2	$2
Capacity Savings per Customer	Residential TOU	$12	$16	$22	$38	$42
	Commercial TOU	$250	$329	$473	$790	$880
	EV TOU	$22	$29	$42	$70	$77
	EV Managed Charging	$63	$82	$119	$198	$220
	Residential Smart Thermostat	$54	$72	$103	$171	$190
Total Savings per Customer	Residential TOU	$13	$17	$24	$39	$43
	Commercial TOU	$278	$354	$507	$816	$910
	EV TOU	$30	$36	$51	$77	$86
	EV Managed Charging	$101	$90	$125	$201	$222
	Residential Smart Thermostat	$56	$73	$105	$173	$192
Total Potential Savings per year	Residential TOU	$29,129	$37,104	$53,108	$85,527	$95,357
	Commercial TOU	$83,694	$106,609	$152,592	$245,740	$273,983
	EV TOU	$1,240	$4,279	$13,478	$32,378	$49,384
	EV Managed Charging	$4,162	$10,766	$32,906	$84,857	$128,259
	Residential Smart Thermostat	$100,154	$131,894	$189,055	$311,072	$345,070

Modeling Assumptions: EV Managed Charging

We modeled EV managed charging as a capacity-focused demand-side resource aimed at reducing Batavia's system peak load, while also delivering additional energy cost savings by shifting charging demand to lower-priced off-peak hours. Unlike some other demand-side programs, we note that EV managed charging does not reduce total electricity consumption; it shifts the timing of that consumption to mitigate grid stress and improve cost-effectiveness.

Our sample program design assumes an opt-in structure with 25% of Batavia's EV owners participating and a 100% response rate when events are called. Currently, there are 129 EV owners in Batavia, with that number expected to grow to 2,624 by 2045 in the **Base Case**.

We assume the program would include up to 150 events per year, with each event lasting four hours and limited to one event per day. Events are modeled to occur during the highest-priced periods of the year (typically July through October) to reflect an upper-bound estimate of system value. During these events, EV load is curtailed during peak hours and shifted to off-peak periods (e.g., hours beginning 0–3, corresponding to midnight charging).

We calculate energy savings as the difference in locational marginal prices (LMP) between the curtailed peak hours and the off-peak replacement hours. Capacity benefits are estimated based on the reduction in EV load during the system peak hour and valued using ComEd's applicable capacity price.

Result: EV Managed Charging

Our modeling indicates that EV managed charging holds strong long-term potential, with total participant benefits increasing significantly over the 2026–2045 horizon. While early-year value is modest, cumulative system impact grows steadily as both participation and avoided capacity costs rise.

By 2045, total participant value reaches $223 per year, assuming enrollment of over 650 participants. This reflects a near doubling of program value compared to 2030.

Energy benefits decline slightly over time on a per-participant basis due to flattening price differentials as more participants shift their charging behavior to off-peak periods.

Capacity benefits are expected to increase materially due to projected rises in capacity prices for the ComEd zone, which magnifies the value of reducing coincident peak demand. These benefits reflect direct load curtailment and shifting events designed to coincide with high system prices and reliability risk. Our current analysis does not include potential vehicle-to-grid (V2G) revenue streams or bidirectional charging, which may become more relevant in later years as enabling technologies and regulatory frameworks evolve.

Summary of Total Benefits ($ per participant-year)

Year	Energy Value	Capacity Value	Total Benefit
2026	$38	$63	$101
2027	$12	$67	$79
2028	$10	$73	$84
2029	$9	$77	$86
2030	$8	$82	$90
2031	$8	$88	$96
2032	$8	$93	$101
2033	$8	$99	$107
2034	$7	$107	$114
2035	$7	$119	$125
2036	$6	$130	$136
2037	$5	$141	$146
2038	$4	$158	$162
2039	$3	$181	$184
2040	$3	$198	$201
2041	$3	$205	$208
2042	$2	$211	$214
2043	$2	$221	$224
2044	$2	$224	$226
2045	$2	$220	$222

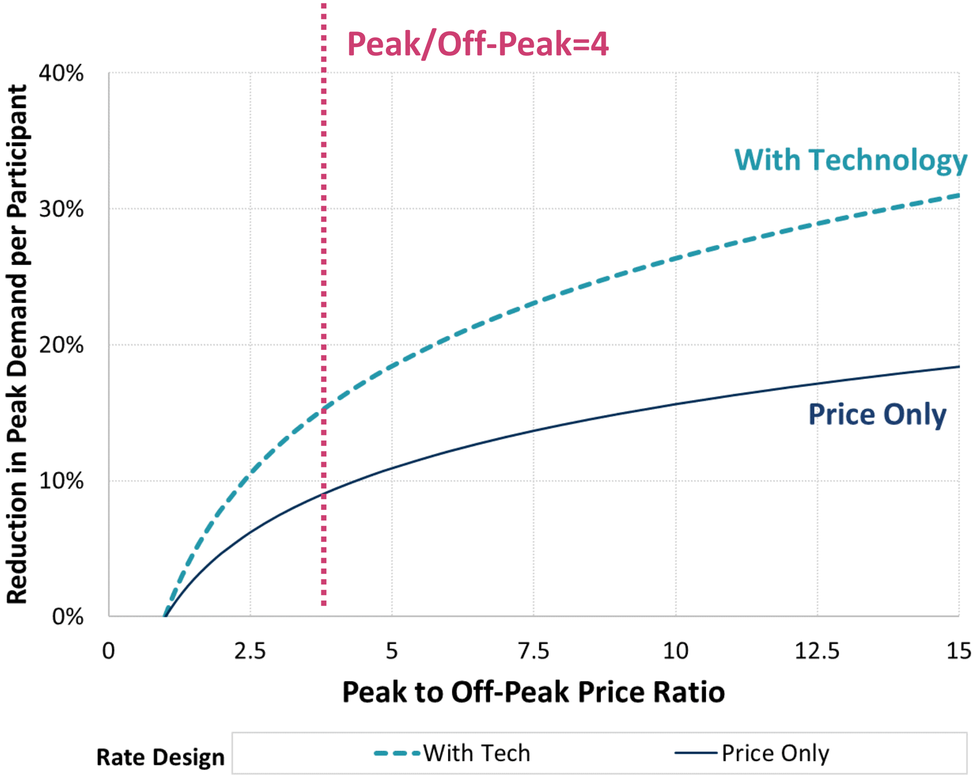
Modeling Assumptions: TOU Programs

We evaluated the potential of TOU rate designs for residential and small commercial customers by modeling load-shifting behavior aligned with Batavia's peak demand profile. TOU programs were assumed to operate on an opt-in basis and serve primarily as load-shifting resources without reducing total energy consumption.

We assumed a TOU rate structure featuring a 4:1 peak-to-off-peak price ratio, which is consistent with pilot designs observed across utilities. Based on historical TOU program data and estimated price elasticities, we assumed a 9% reduction in peak demand per participant under this pricing differential, without enabling any additional direct load control technology. The level of customer responsiveness is supported by data from the Brattle Arcturus Database, which aggregates over 400 observations from 80 pilots across four continents.

We note that adding direct load control capabilities could materially increase the peak demand reduction potential per customer, as illustrated by the "With Technology" response curve in the chart. However, for the purpose of this modeling, we applied the more conservative assumption of price-only response.

The Arc of Price Responsiveness by Technology



Source: Brattle Arcturus Database that has 410 observations from 80 pilots on four continents. Technologies include programmable communicating thermostat (PCT) or smart thermostat, A/C switch, and any load control devices.

Modeling Program Potential: TOU Programs

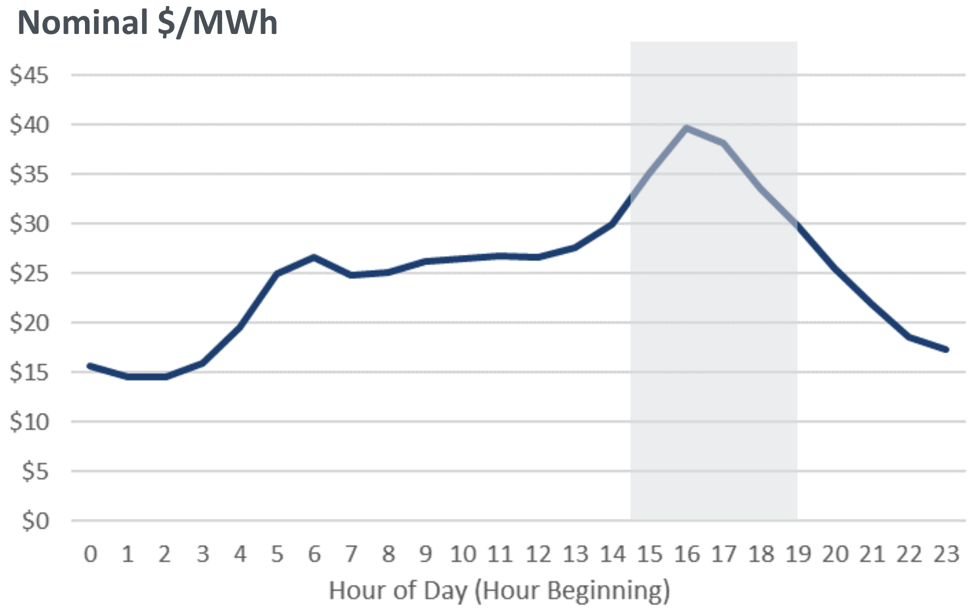
To evaluate the load-shifting potential of TOU rate designs for residential and small commercial customers, we modeled program impacts based on Batavia's system peak characteristics and typical price profiles.

Batavia's system typically peaks during the afternoon hours, with highest demand observed between hour beginning (HB) 14–18, or 2 PM to 6 PM. In parallel, energy prices (LMPs) tend to spike during HB15–20, creating a strong incentive to shift consumption to later off-peak hours. As shown in the accompanying 2024 PJM energy price curve, this alignment presents a clear opportunity for targeted demand shifts.

We assume that load shifting occurs on weekdays during the summer season, defined as May 1 through September 30, excluding weekends and holidays. The modeled TOU program is designed to encourage customers to shift usage away from peak hours (HB15–18) toward later, lower-cost periods (e.g., HB19–22), without reducing total energy consumption.

We assume no total load reduction under the TOU rate, rather a redistribution of usage across hours to relieve peak stress and reduce exposure to high wholesale market prices.

2024 Hourly PJM Energy Prices By Hour of Day



Result: TOU Programs

Our analysis indicates that TOU rates can offer meaningful system value, particularly for the commercial sector, where concentrated afternoon peak demand translates to strong capacity savings.

Across both residential and commercial segments, capacity value comprises the majority of total benefits. The commercial TOU program delivers consistently high per-participant value, rising from $278 in 2026 to $910 by 2045, with capacity contributions making up over 90% of total benefits. This strong and steadily increasing value suggests that a targeted commercial rollout may be an effective and practical near-term strategy for Batavia.

In contrast, residential TOU programs yield lower per-customer benefits, starting at $13 in 2026 and reaching $43 by 2045. These results suggest that residential TOU may be more viable when paired with complementary measures, such as EV charging, peak-time rebates, or automated controls, or if market conditions evolve to increase energy or capacity prices.

Notably, the modeled TOU programs deliver peak reduction benefits that are comparable to those achievable with battery storage, suggesting that TOU rates can play a cost-effective role in Batavia's broader demand-side strategy.

Summary of Total Benefits ($ per participant-year)

	Residential			Commercial		
Year	Energy Value	Capacity Value	Total Benefit	Energy Value	Capacity Value	Total Benefit
2026	$1	$12	$13	$28	$250	$278
2027	$1	$13	$14	$24	$269	$293
2028	$1	$14	$15	$24	$288	$312
2029	$1	$15	$16	$25	$308	$333
2030	$1	$16	$17	$25	$329	$354
2031	$1	$17	$18	$27	$349	$376
2032	$1	$18	$19	$30	$370	$400
2033	$2	$19	$20	$34	$390	$425
2034	$2	$20	$22	$35	$424	$459
2035	$2	$22	$24	$34	$473	$507
2036	$2	$24	$26	$34	$513	$547
2037	$2	$27	$28	$32	$560	$592
2038	$1	$30	$31	$30	$624	$654
2039	$1	$34	$35	$27	$717	$744
2040	$1	$38	$39	$26	$790	$816
2041	$1	$39	$40	$27	$814	$841
2042	$1	$40	$41	$27	$839	$866
2043	$1	$42	$43	$27	$882	$909
2044	$1	$43	$44	$28	$895	$923
2045	$1	$42	$43	$30	$880	$910

Modeling and Results: EV TOU

We modeled an EV TOU program aimed at shifting electric vehicle charging to off-peak periods as a means of reducing system demand and capturing energy and capacity value.

The program is designed as an opt-in offering, where participating EV owners are incentivized to shift charging away from the typical system peak period. The modeled load shifting strategy assumes a shift from HB15–18 to HB0–3, corresponding to late evening or overnight charging.

Based on findings from other EV TOU pilots and the academic literature, we assume a 35% reduction in peak demand for participating vehicles. For participants who entirely avoid charging during the peak period, their capacity benefit may go up higher by three times, which will be consistent with the higher value of full curtailment during critical hours (assumptions used for managed charging programs).

We also recognize potential challenges: if a large number of vehicles are programmed to begin charging simultaneously after peak hours, new load spikes may occur during off-peak periods. Staggered charging windows or managed charging may be more effective and grid-friendly alternatives to mitigate this.

The results show moderate and increasing participant-level benefits, with total benefits growing from $30 in 2026 to $86 by 2045, driven primarily by capacity savings. As with managed charging, the viability of EV TOU rates for Batavia depends on long-term EV adoption trends and achievable participation rates.

Summary of Total Benefits ($ per participant-year)

Year	Energy Value	Capacity Value	Total Benefit
2026	$8	$22	$30
2027	$7	$24	$31
2028	$7	$26	$33
2029	$7	$27	$34
2030	$7	$29	$36
2031	$8	$31	$39
2032	$9	$32	$41
2033	$10	$35	$44
2034	$10	$38	$47
2035	$10	$42	$51
2036	$10	$45	$55
2037	$9	$49	$58
2038	$9	$55	$64
2039	$8	$63	$71
2040	$7	$70	$77
2041	$8	$72	$80
2042	$8	$74	$82
2043	$8	$78	$85
2044	$8	$79	$86
2045	$8	$77	$86

Notes: We assume that additional capacity market benefits due to avoided transmission and distribution (T&D) losses are offset by PJM RTO's negative capacity market reserve margin (-8% in UCAP terms, assumed to remain constant from 2026 to 2045).

Modeling Assumptions: Residential Smart Thermostat

We modeled a residential smart thermostat program as a flexible demand-side resource designed to reduce Batavia's system peak load and improve grid reliability. The primary value of the program is derived from avoided capacity costs, as energy savings are incidental to the primary control strategy. Smart thermostat programs are attractive due to their ability to automate customer participation with minimal user intervention, making them both scalable and low-burden especially for residential participants.

Our modeling assumes a program design that calls up to 20 thermostat adjustment events per summer season, with each event lasting three hours, scheduled during peak hours between HB15–17 (3 PM to 5 PM). To maintain occupant comfort while maximizing grid value, the program includes two hours of pre-cooling prior to each event, where indoor temperatures are slightly reduced ahead of curtailment. Following the curtailment window, we assume a four-hour snapback period, during which some of the curtailed load returns as cooling demand rebounds. Based on industry experience and program data, we assume that approximately 40% of the curtailed energy (kWh) returns during this post-event period.

Setpoint adjustments are modeled to be moderate—typically a few degrees Fahrenheit—to avoid customer discomfort while still achieving meaningful demand reductions. These adjustments are automated and centrally controlled, reducing the need for manual customer action and improving program reliability.

Based on impact results from PG&E's SmartAC program and similar deployments, we assume a peak demand reduction of 0.5 kW per participating household.

Source: Peak Impact based on PG&E's SmartAC program results.

Results: Residential Smart Thermostat

The projected benefits of the residential smart thermostat program are expected to increase steadily over time, driven primarily by growth in avoided capacity costs. Under the assumptions applied, total household benefits rise from $56 per year in 2026 to $192 by 2045, with capacity value accounting for over 95% of total program value. This trend reflects the escalating capacity price forecast in the ComEd zone, which directly influences the monetized impact of peak demand reductions.

While energy savings are included in the model, their contribution remains small at approximately $2 per year due to the limited curtailment of overall energy usage and the relatively short duration of each event. The primary mechanism for value creation is reducing demand during system peak hours.

Given these benefits, Batavia may be able to design a cost-effective program based on system-level impacts. Typical program cost components include incentive payments, labor and marketing costs, and software or platform fees for demand response management. Benchmarking from similar utility programs suggests average costs ranging from $50 to $100 per participant annually, indicating a strong potential for net benefit under projected conditions.

To further refine the cost-benefit outlook, Batavia may consider conducting a dedicated Distributed Energy Resource potential study, which could assess value under varying participation rates, technology mixes, and avoided infrastructure costs. This would help determine whether broader adoption of residential smart thermostats can play a cost-effective role in Batavia's long-term resource strategy.

Summary of Total Benefits ($ per household-year)

Year	Energy Value	Capacity Value	Total Benefit
2026	$2	$54	$56
2027	$2	$58	$60
2028	$2	$63	$64
2029	$2	$67	$69
2030	$2	$72	$73
2031	$2	$76	$78
2032	$2	$80	$83
2033	$3	$85	$88
2034	$3	$92	$95
2035	$3	$103	$105
2036	$2	$112	$114
2037	$2	$122	$124
2038	$2	$136	$138
2039	$2	$155	$158
2040	$2	$171	$173
2041	$2	$176	$178
2042	$2	$182	$184
2043	$2	$191	$193
2044	$2	$193	$196
2045	$2	$190	$192

Notes: We assume that additional capacity market benefits due to avoided transmission and distribution (T&D) losses are offset by PJM RTO's negative capacity market reserve margin (-8% in UCAP terms, assumed to remain constant from 2026 to 2045).

Appendix F: Performance of Portfolio Options

Performance of Portfolio Options & Policy Pillars

The next two slides provide details for the star ratings by resource and planning priority (slide 70).

6. SUPPLY-SIDE OPTIONS

Performance of Portfolio Options & Policy Pillars

The table below compares how the resource options currently being considered in the IRP may support Batavia's four energy planning priorities. The intent is to provide a simple and transparent way to illustrate the relative benefits and tradeoffs associated with each resource option.

The star ratings are qualitative and directional: more stars generally indicate that a resource may provide stronger benefits toward a specific planning priority relative to the other options being considered.

Batavia Priority	4-Hour Battery Storage (BESS)	Standalone Solar PV	Standalone Wind	Solar + 4-Hour Battery	Natural Gas RECIP	Demand Response	Electric Vehicle Programs
Affordability	★★	★★	★★	★★	★★★	★★	★
Resiliency	★★★	★	★	★★★	★★★	★	★
Sustainability	★	★★★	★★★	★★★	★	★★	★★★
Adaptability	★★	★★★	★★	★★★	★★★	★	★★
	Supply-Side					Demand-Side	

Note: Explanations for ratings provided in Appendix F.

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Performance of Portfolio Options & Policy Pillars: 1/2

Batavia Priority	4-Hour Battery Storage (BESS)	Standalone Solar PV	Standalone Wind	Solar + 4-Hour Battery	Natural Gas RECIP	Demand Response	Electric Vehicle Programs
Affordability	Can reduce exposure to PJM capacity and peak energy costs; economics remain sensitive to charging costs and utilization; requires meaningful upfront capital investment.	No fuel cost and relatively stable long-term pricing; intermittency limits full capacity value; economic value depends on production profile and market prices.	Competitive long-term energy pricing; no fuel price exposure; economic value subject to transmission and market conditions.	Combines renewable generation with peak-shifting capability; higher capital costs than standalone solar.	Strong capacity value and dispatchability; can hedge against PJM capacity price exposure; less land needs compared to some alternatives.	Can reduce peak demand and capacity costs; benefits limited by current infrastructure and participation levels.	Requires charging infrastructure investment; potential long-term benefits remain uncertain.
Resiliency	Fast-response dispatchable resource; supports peak management and operational flexibility; can provide local reliability support.	Non-dispatchable resource; limited contribution during peak or outage conditions without storage.	Non-dispatchable resource; limited local reliability contribution.	Greater operational flexibility than standalone renewables; can shift solar generation into higher-value periods.	Highly dispatchable and operationally flexible; strong local reliability and capacity contribution.	Limited dispatchability without AMI or advanced controls; current programs more TOU-oriented than reliability-oriented.	Limited near-term reliability contribution without managed charging capability.

Performance of Portfolio Options & Policy Pillars: 2/2

Batavia Priority	4-Hour Battery Storage (BESS)	Standalone Solar PV	Standalone Wind	Solar + 4-Hour Battery	Natural Gas RECIP	Demand Response	Electric Vehicle Programs
Sustainability	Does not generate energy directly; charging may occur during periods with higher marginal fossil generation in PJM; sustainability benefits improve as grid mix decarbonizes over time.	Zero-emission renewable resource; strong alignment with CEJA and long-term decarbonization goals.	Zero-emission renewable resource; strong alignment with CEJA and long-term decarbonization goals.	Supports renewable integration and reduced emissions; sustainability profile still influenced by charging behavior.	Fossil-fuel-based resource with direct emissions; less aligned with long-term decarbonization goals.	Reduces peak demand and need for incremental generation; supports more efficient system utilization.	Supports transportation electrification and long-term emissions reduction goals.
Adaptability	Modular and provide flexible dispatchable resource; long-term economics and use cases remain market-dependent.	Modular and scalable; limited operational flexibility once deployed.	Long asset life but less flexible operationally; expansion dependent on siting and transmission availability.	Flexible operating profile but more complex and capital-intensive; adaptability similar to other modular resource options.	Modular technology that can be expanded incrementally; potential future fuel flexibility (e.g., hydrogen blends / renewable fuels); strong operational flexibility under changing system conditions.	Current lack of AMI limits operational flexibility and scalability.	Potential future flexibility opportunity as EV adoption and managed charging evolve; current operational capabilities remain limited without AMI infrastructure.

Appendix G: Glossary

Glossary

AEO	Annual Energy Outlook
AS	Ancillary Service
ATB	Annual Technology Baseline
Batavia	City of Batavia
BESS	Battery Energy Storage System
Btu	British Thermal Units
BTM	Behind-The-Meter
CC	Combined Cycle
CEJA	Climate And Equitable Jobs Act
CETL	Capacity Emergency Transfer Limit
CETO	Capacity Emergency Transfer Objective
C&I	Commercial and Industrial
City	City of Batavia
CMAP	Chicago Metropolitan Agency for Planning
ComEd	Commonwealth Edison
CONE	Cost of New Entry
CT	Combustion Turbine
CRGA	Clean and Reliable Grid Affordability Act
DERs	Distributed Energy Resources
DSR	Demand-Side Resources
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capacity
EV	Electric Vehicle
EVI	Electric Vehicle Infrastructure
FEOC	Foreign Entity Of Concern
GW	Gigawatts
GWh	Gigawatt-Hours
HB	Hour Beginning
HB 2902	Illinois House Bill 2902
ICAP	Installed Capacity
IL	Illinois
IMHR	Implied Market Heat Rate
IRP	Integrated Resource Plan
IRA	Inflation Reduction Act
ITC	Investment Tax Credit
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-Hour
LCOE	Levelized Cost of Energy
LDAs	Locational Delivery Areas
LMP	Locational Marginal Price
LNG	Liquefied Natural Gas
MISO	Midcontinent Independent System Operator
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-Hour
NETL	National Energy Technology Laboratory
NIMPA	Northern Illinois Municipal Power Agency
NPV	Net Present Value
O&M	Operations And Maintenance
PCT	Programmable Communicating Thermostat
PSCG	Prairie State Generating Center
PTC	Production Tax Credit
RECIP	Reciprocating Internal Combustion Engine
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
SB 25	Senate Bill 25
TOU	Time Of Use
TW	Terawatt
TWh	Terawatt-Hour
UCAP	Unforced Capacity
V2G	Vehicle-To-Grid
W	Watt
Wh	Watt-Hour