Alliant Energy
Legal Department
200 First Street SE
P.O. Box 351
Cedar Rapids, IA 52406-0351

Office: (319) 786-4505
alliantenergy.com

November 20, 2020

Executive Secretary
Iowa Utilities Board
1375 East Court Avenue, Room 69
Des Moines, IA 50319-0069

RE: Interstate Power and Light Company
Docket No. RPU-2019-0001
Iowa Clean Energy Blueprint: 2020 Resource Planning

Dear Executive Secretary:

Interstate Power and Light Company (IPL) is pleased to submit its Iowa Clean Energy Blueprint resource planning analysis conducted with Iowa stakeholders during 2020, pursuant to the Non-Unanimous Partial Settlement Agreement in Docket No. RPU-2019-0001.[1] IPL has appreciated the collaboration, active involvement and diverse viewpoints provided by stakeholders throughout this process and the analytical support services provided by Charles River Associates.

The robust analysis contained within this informational filing identifies the potential for customers to avoid more than $300 million in costs over the next 35 years. This resource planning analysis will be a key resource to help inform IPL's decision-making as we continue to provide affordable, reliable and environmentally sustainable energy to meet our customer's needs.

The Iowa Clean Energy Blueprint resource planning analysis provides a detailed summary of the process IPL undertook to model existing supply resources in the Midcontinent Independent System Operator (MISO) Zone 3, potential future scenarios, pathways for our existing generation resources, and portfolios to assess a variety of generation options across a range of planning metrics, including a full portfolio cost and financial analysis. The key conclusions of the analysis are summarized in the final report.

IPL deems certain information contained in this report to be confidential. On June 9, 2020, the Iowa Utilities Board (Board) issued an Order Granting Application for Confidential Treatment and Request for Limited Waiver (June 9 Order) allowing IPL to share confidential resource planning information without filing separate requests for confidentiality and

[1] Pursuant to Article IX, Section E of the Non-Unanimous Partial Settlement Agreement, IPL agreed to file a notice of the resource planning process results in RPU-2019-0001 or another appropriate docket.

associated affidavits. IPL has enclosed both a public and confidential version of this report, consistent with the June 9 Order. IPL appreciates the Board's approval of the limited waiver which has allowed for a streamlined information sharing process.

Very truly yours,

/s/ Andrew D. Cardon

Andrew D. Cardon
Senior Attorney
319.768.4236
andrewcardon@alliantenergy.com

ADC/tab
Enclosures

Prepared for:
Alliant Energy

Alliant Energy's
Iowa Clean Energy Blueprint:
2020 Resource Planning

Prepared by:
Charles River Associates

Date: November 20, 2020

Table of contents

Table of Figures

Table of Acronyms

A/S	Ancillary Services
AEO	Annual Energy Outlook
ALTW	Alliant West Zone
BGS	Burlington Generating Station
Btu	British thermal unit
CAGR	Compound annual growth rate
CapEx	Capital expenditure
CO_2	Carbon dioxide
COR	Cost of Removal
CRA	Charles River Associates
DER	Distributed energy resource
DG	Distributed generation
DOE	U.S. Department of Energy
DR	Demand response
DSM	Demand-side management
ELPC	Environmental Law and Policy Center
EV	Electric vehicle
ICAP	Installed capacity
IEC	Iowa Environmental Council
IPL	Interstate Power and Light Company
IRP	Integrated resource plan
ISO	Independent system operator
ITC	Investment tax credit
LEG	Large Energy Group
LDC	Local distribution company
LMP	Locational marginal price
LSE	Load Serving Entity
LTSA	Long-term service agreement
MISO	Midcontinent Independent System Operator
MTEP	MISO Transmission Expansion Planning
NPV	Net present value
NPVRR	Net present value of revenue requirements
NREL	National Renewable Energy Laboratory
OCA	Office of Consumer Advocate
PPA	Power purchase agreement
PTC	Production tax credit
PV	Photovoltaic
PY	Planning Year
RFP	Request for proposal
SC	Sierra Club
UCAP	Unforced capacity
VOM	Variable operating and maintenance
WoodMac or WM	Wood Mackenzie
ZRC	Zonal resource credit

1. Executive Summary

Alliant Energy conducted a collaborative resource planning effort for its Iowa utility - Interstate Power and Light Company ("IPL") - with Iowa stakeholders[1] during 2020. This effort will inform IPL's decision-making as part of the Clean Energy Blueprint to enable the company to best meet its customers' needs for affordable, reliable, and environmentally sustainable energy. IPL initiated the resource planning process in early 2020 and carried out the analysis in a phased fashion throughout the remainder of the year, engaging with stakeholders, seeking their input, and incorporating their diverse viewpoints along the way for a robust analysis. This collaboration was undertaken at a pace and framework aligned with our commitments in the Non-Unanimous Partial Settlement Agreement reached in Docket No. RPU-2019-0001.

In supporting the core quantitative analysis associated with the Clean Energy Blueprint process, Charles River Associates ("CRA") partnered with IPL to develop an enhanced resource planning process, using state-of-the-art tools and techniques to measure and evaluate future portfolio alternatives against a range of planning metrics. As part of this process, CRA implemented a two-phased modeling approach to (i) first evaluate IPL's existing owned and operated generation fleet options and (ii) then perform refinements on a short-list of candidate portfolios. Both stages of analysis evaluated portfolio options across a range of scenarios developed by IPL and its stakeholders. The modeling was performed by CRA using the Aurora Electric Modeling Forecasting and Analysis Software, licensed by Energy Exemplar, along with CRA's proprietary financial module.

In evaluating portfolio options, IPL incorporated a number of key planning objectives, including affordability, rate stability, flexibility of supply, reliability, and sustainability. The key conclusions of the Clean Energy Blueprint analysis include the following:

- Retirement of the Lansing coal plant by 2022 is lower cost than operating the plant through the end of its useful life in 2037;
- Conversion of the Burlington Generation Station to burn natural gas in 2021 allows IPL to maintain approximately 150 MW of relatively low-cost capacity;
- Acquisition of up to 400 MW of solar capacity by the end of 2023 serves to replace retiring coal capacity and take advantage of the investment tax credit, providing long-term cost benefits to customers;
- Development of approximately 28 MW of distributed storage and 94 MW of distributed solar plus storage by 2030 may be a means of procuring cost-effective capacity and energy for customers, especially if IPL can prioritize project locations where significant avoided distribution costs can be realized;
- Implementation of energy efficiency measures that are designed to reduce peak load by approximately 200 MW and average energy consumption by approximately 130 MW by 2040 may be cost-effective.

Overall, the Clean Energy Blueprint analysis identified the potential for customers to avoid more than $300 million in costs over the next 35 years.[2]

[1] See Section 2 for information on stakeholders and participation.

[2] Portfolio 3b vs Portfolio 1, sum of annual nominal cost differences.

While this Clean Energy Blueprint analysis and stakeholder engagement will help inform IPL's near-term resource planning decisions, future decisions depend on consideration of a number of factors, such as the ability to secure market capacity purchases at the rates used in this analysis, the actual costs of replacement resources, and other legal, regulatory, financial and operational considerations. The analysis contained in this report and these factors will inform IPL's future resource decisions and implementation plans subsequent to this analysis.

This report provides a summary of the resource planning process and is organized as follows:

- **Chapter 2** provides an overview of the **modeling and planning process**, as well as a summary of the key stakeholder engagement activities.
- **Chapter 3** presents a summary of IPL's existing supply resources and expected demand outlook and documents the **data exchange and model calibration** efforts undertaken by the IPL and CRA teams to establish the core modeling framework for the resource planning process within the Clean Energy Blueprint.
- **Chapter 4** provides a detailed summary of the **scenario development** process, including an overview of the major scenario concepts, as well as documentation of key assumptions and modeling outcomes; and stakeholder input.
- **Chapter 5** presents a summary of the **existing fleet operational pathways** that were developed for IPL's generating fleet. As part of this process, the IPL and CRA teams defined distinct retirement dates for several IPL owned and operated thermal generating units, with associated expenditure estimates at the plant, and then performed a least cost optimization in the Aurora model to identify potential replacement resources.
- **Chapter 6** provides a summary of the **Phase I portfolio analysis**, which assessed the existing fleet options across a range of planning metrics, including a full portfolio cost and financial analysis.
  - A dispatch analysis of these portfolios was performed in the Aurora dispatch model, and projections for the IPL portfolios' variable costs, contract costs, and market sales and purchases were processed through CRA's financial module. The Aurora model is similar in functionality to tools that IPL has used in past resource planning exercises, such as EGEAS and PROMOD, but it offers additional flexibility and functionality.[3]
  - CRA's financial module accounts for the utility's specific financial structure, expected capital expenditures and fixed costs, and tax equity financing for newly built renewables. Results of this financial modeling include the net present value of revenue requirements over short-, medium-, and long-term planning horizons, as well as generation rates and sustainability metrics.

[3] Like PROMOD, Aurora can simulate competitive dispatch throughout the MISO market and project power market prices through a chronological dispatch simulation. For the Energy Blueprint, CRA is using Aurora's expanded functionality, unavailable in PROMOD, to efficiently develop multiple market scenarios including regional capacity expansion and operational analysis and hourly price forecasts. Note that IPL continues to use PROMOD for nodal price analysis, consistent with MISO's transmission planning process.

Like EGEAS, Aurora can perform utility portfolio cost accounting and least-cost optimization analysis to identify attractive resource plans. Unlike EGEAS, however, Aurora is run in chronological hourly format rather than in a simplified load duration curve format, allowing for a more granular assessment of intermittent resources and new technology options like storage. CRA's financial module develops full revenue requirement projections, which are being used in the Energy Blueprint analysis.

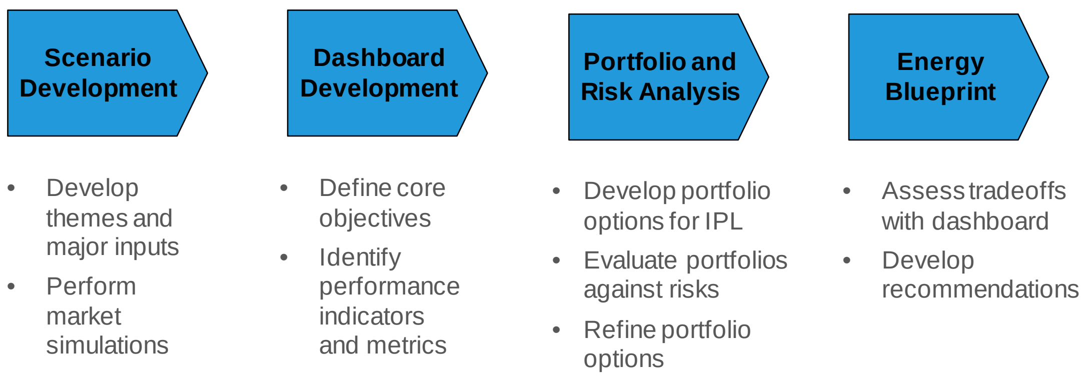
- **Chapter 7** presents the **portfolio refinements** evaluated in the Phase 2 portfolio analysis. These portfolio refinements incorporated updates to the best-performing Phase I portfolios based on IPL's ongoing review of options and stakeholder input.
- **Chapter 8** provides the **results of the Phase 2 portfolio analysis**.
- **Chapter 9** defines the **"Dashboard"** of utility objectives and metrics used to evaluate the portfolios against each other.
- **Chapter 10** presents a summary of **key findings** of the resource planning analysis component of IPL's Clean Energy Blueprint and concluding thoughts.

2. Overview: Modeling and Planning Process

IPL and CRA conducted the resource planning for the Clean Energy Blueprint according to a process with four major elements, as described below and illustrated in Exhibit 2.1:

- **Scenario development** to identify major external uncertainties against which to evaluate IPL alternatives;
- **Dashboard development** to define core objectives and ways to measure performance against them;
- **Portfolio and risk analysis** to develop IPL-specific portfolio options and evaluate them against scenario risks and other objectives; and
- **Clean Energy Blueprint recommendations** based on performance of the portfolio options against the dashboard metrics.

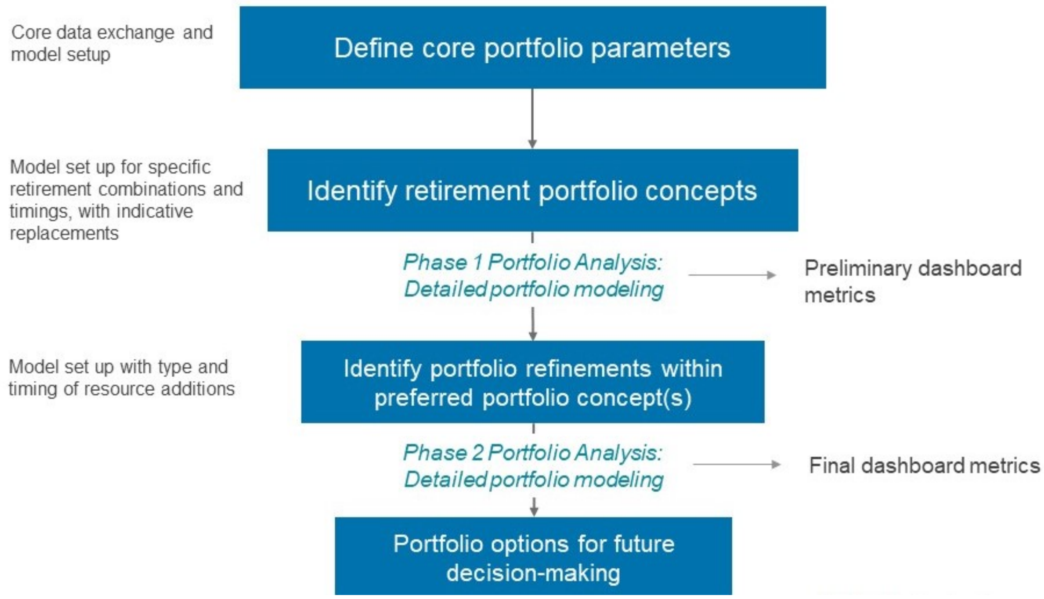
Exhibit 2.1 IPL Clean Energy Blueprint Process Overview



The portfolio and risk analyses were performed in a phased fashion to allow for stakeholder input and portfolio refinement as additional information was acquired and to assess a range of options against multiple criteria, including affordability, stability, flexibility, reliability, and sustainability. The major steps in the core analysis process are described below and illustrated in Exhibit 2.2:

- Definition of core portfolio parameters and major inputs and assumptions;
- The identification of potential operational pathways for IPL's existing fleet and the evaluation of such options through detailed portfolio analysis – Phase 1; and
- The analysis of additional portfolio "refinements" after the Phase 1 analysis to test a range of future generation options across a narrowed set of retirement pathways – Phase 2.

Exhibit 2.2 IPL Energy Blueprint Portfolio Analysis Process Overview



2.1. Stakeholder Participation

Throughout the Clean Energy Blueprint process, IPL held meetings[4] with stakeholders for the purpose of informing and collaborating with them on the market planning scenarios, operational pathways for consideration, new resource options, and key input assumptions and output results. In addition, IPL engaged in a collaborative resource sharing effort wherein IPL provided written responses and supporting information and data to help address stakeholder questions and held several meetings with individual stakeholders. The stakeholder feedback during and after the workshops was instructive to the Clean Energy Blueprint process, as IPL and CRA reviewed the modeling assumptions with stakeholders and made refinements to certain inputs or portfolio options.[5] For example, stakeholders requested and developed their own scenarios and portfolios which IPL ran (consistent with the terms of the Settlement Agreement in Docket No. RPU-2019-0001 where IPL agreed to perform a reasonable number of stakeholder requested runs) and which defined a wider set of scenario and portfolio considerations.[6] These scenarios are further described in Chapter 4.

[4] IPL conducted Energy Blueprint stakeholder meetings on January 27, February 25, April 23, May 18, September 10, and October 20, 2020.

[5] Stakeholder feedback and IPL's responses to feedback has been documented in confidential filings submitted in Docket No. RPU-2019-0001.

[6] Article IX.C. provides, in part, "IPL's agreement to conduct these runs does not constitute endorsement by IPL of these modeling run inputs or outputs." Consistent with this provision, the inclusion in this report of the runs requested by the stakeholders is not an endorsement by IPL of those modeling inputs or runs.

The following Stakeholders were invited or participated in the Clean Energy Blueprint process: staff from the Iowa Utilities Board, the Office of Consumer Advocate, a division of the Iowa Department of Justice (“OCA”), the Environmental Law and Policy Center and Iowa Environmental Council (“ELPC/IEC"), the International Brotherhood of Electrical Workers, Local 204 (IBEW Local 204), Iowa Business Energy Coalition (“IBEC”), the Large Energy Group (“LEG”), Large General Service Group (“LGSG”), Sierra Club (“SC”), Decorah Area Group, ITC Midwest, and Walmart Stores, Inc. (Walmart).

3. Existing IPL Supply and Demand and Model Set Up

The first major step in establishing a functional modeling framework for the resource planning component of the Clean Energy Blueprint analysis was to incorporate IPL data into the Aurora model and perform a calibration exercise with historical information and IPL's internal forecasts. CRA worked with IPL to first access and review all relevant data associated with generation supply and demand, and then to perform a series of model tests to validate proper calibration to actual observations. The following sections of this chapter provide additional detail on IPL's existing supply and demand profile, with Section 11.1 in the Appendix providing detail on the model calibration exercises that were performed.

3.1. Core Data Exchange and Model Setup

The Aurora model performs chronological market dispatch and portfolio accounting (among other functionalities),[7] which accounts for all plant operational parameters, contract terms, and load profiles. The model can be run for a broad market region and for individual utility portfolios. The Aurora model used in the development of market scenarios (See Chapter 4) simulates the entire Eastern Interconnect, with a focus on the MISO footprint. When evaluating the IPL portfolio, however, the detailed supply and demand parameters need only be specified for the core utility under evaluation. The following sections of this chapter provide detail on various model inputs associated with IPL's supply resources (owned and contracted) and demand growth expectations.

3.1.1. Supply Resources Characteristics and Costs

As of planning year ("PY") 2020, IPL's generation fleet is composed of a diverse set of owned and contracted resources, with an unforced capacity ("UCAP")[8] composition of coal (33%), gas (44%), wind (11%), demand side measures ("DSM") (10%), and other resources. The model development for IPL's supply resources involved consistent engagement between IPL and CRA, in which unit operational parameters, cost characteristics, and specific contract details were exchanged. Exhibit 3.1 through Exhibit 3.3 summarize IPL's supply-side assumptions for the existing portfolio.

Key operational inputs for the thermal generating resources in the Aurora model include:

- Nameplate capacity (or maximum dispatch capability) of the generating units (by month, as appropriate) and minimum capacity ratings;[9]
- Maintenance schedules, defined as when a unit is temporarily taken offline for routine maintenance;
- Forced outage rates, or the percentage of time the resource is unavailable due to unscheduled outages;

[7] The Aurora model functionalities were presented in the January 27, 2020 stakeholder meeting.

[8] Unforced capacity or UCAP is the term used to define capacity that is accredited by MISO to satisfy Resource Adequacy obligations. For example, most thermal resources are accredited their summer capacity less an expected forced outage rate, while intermittent resources like wind and solar are currently accredited capacity based on historical performance (or regional benchmarks prior to the in-service date of new resources) during system peak hours.

[9] Note that the core Aurora modeling framework takes a nameplate capacity number for the maximum dispatch capability, which is adjusted for seasonality and for forced outage and maintenance, as appropriate for dispatch.

- Ramp rates, minimum time a unit must be running if committed ("Minimum Up Time" in Aurora), minimum time a unit must be down after turning off ("Minimum Down Time" in Aurora);
- Assumptions about "Must Run" behavior, where a unit will be forced to dispatch at least up to minimum capacity at all times;
- Plant heat rates;
- Plant emission rates and water usage by generating unit; and
- Startup costs and variable and operating maintenance costs.

Aurora models the economic dispatch of generating resources based on electricity price and all variable operating costs. To reflect actual plant dispatch behavior, delivered fuel prices and all associated variable costs were represented in Aurora. Delivered coal price projections were developed based on IPL's market knowledge and existing forward contracts. Natural gas price outlooks were based on Wood Mackenzie's ("WoodMac") North American Power & Renewables Tool,[10] while transportation delivery and local distribution company adders to gas plants were provided by IPL. The range of fuel price outlooks used in the scenario analysis is described in more detail in Chapter 4.

Exhibit 3.1 IPL Thermal Generating Resources Assumptions

Resource Name	***Unit***	***Fuel Type***	***Capacity in Aurora (MW)***	***UCAP (MW)***	***Heat Rate at Maximum (Btu/kWh)***	***Baseline End Date***	***Notes***
Burlington	CT1	Gas	13			5/31/2026	
	CT2	Gas	13			5/31/2026	
	CT3	Gas	13			5/31/2026	
	CT4	Gas	13			5/31/2026	
Burlington Generation Station ("BGS")	1	Coal	197			10/1/2021	(1)
BGS Gas Conversion		Gas	85			5/31/2026	(1)
Emery Generation Station	CT1-2, ST1-2	Gas	542.6			5/31/2039	
Louisa (not IPL operated)		Coal	750			6/1/2040	(2)
George Neal North (not IPL operated)	3	Coal	510			6/1/2035	(2)
George Neal South (not IPL operated)	4	Coal	650			6/1/2040	(2)

[10] WoodMac. *North America Power & Renewables Long-Term Outlook: H1 2019.* Wood Mackenzie. September 2019.

Resource Name	***Unit***	***Fuel Type***	***Capacity in Aurora (MW)***	***UCAP (MW)***	***Heat Rate at Maximum (Btu/kWh)***	***Baseline End Date***	***Notes***
Lansing	4	Coal	251.4			12/31/2037	
Lime Creek turbines	1	Oil	34			12/31/2031	
	2	Oil	34			12/31/2031	
Marshalltown CC	CT1-2, ST1-2	Gas	668.4			-	
Marshalltown CT	CT1	Gas	48			6/1/3027	
	CT2	Gas	48			6/1/3027	
	CT3	Gas	48			6/1/3027	
Ottumwa	1	Coal	705			6/1/2034	(3)
Prairie Creek	1	Coal	10			5/31/2025	(4)
	3	Coal	16			5/31/2025	(4)
	3	Gas	24.7			5/31/2035	(4)
	4	Gas	105			5/31/2035	

All baseline end dates are for modeling purposes only, and not a retirement commitment by IPL.

Notes:

1) On September 2, 2015, IPL entered into a Consent Decree with the U.S. Environmental Protection Agency, the State of Iowa, Linn County, Iowa, and the Sierra Club ("Consent Decree"). Under the terms of the Consent Decree, Burlington Generating Station ("BGS" or "Burlington") must be retired or refueled no later than December 31, 2021. In the base Clean Energy Blueprint assumptions BGS ceases coal-fired operation on October 1, 2021 and converts to an 85 MW gas peaking unit that comes online on January 1, 2022.

2) The capacities represent the full plant, while the UCAP in the table reflect IPL's ownership share in these coal units, which are operated by MidAmerican Energy Company. IPL's ownership shares are the following: Louisa (4%), George Neal North Unit 3 (28%), and George Neal South Unit 4 (25.7%).

3) The capacity in the table represents the full plant, while the UCAP reflects that IPL owns a partial share of Ottumwa Unit 1, a coal unit that the utility operates.

4) Under the terms of the Consent Decree, no later than December 31, 2025, IPL shall retire or refuel Prairie Creek Unit 3. Prairie Creek Unit 3 is a cogeneration unit that provides electric service to IPL electric customers and steam to industrial steam customers. IPL has steam customer contracts through the end of 2025, and those customers rely on the steam production of the Prairie Creek Unit 3 boiler. Prairie Creek Unit 1 is currently anticipated to be retired in 2025, and Prairie Creek Unit 3 is anticipated to be is converted into a 25 MW gas unit that comes online on August 1, 2025.

In addition, IPL owns and contracts through power purchase agreements ("PPA") a number of renewable resources, primarily wind, which are summarized in Exhibit 3.2 below. IPL provided CRA with operational parameters for these resources, such as nameplate capacities, hourly capacity factor shapes (which were summarized for a representative week in each month), and contract terms (e.g. prices, beginning and end date) where applicable.

Exhibit 3.2 IPL Wind Owned and PPA Contracted Resource Assumptions

Name	***Fuel Type***	***Ownership Type***	***Capacity in Aurora (MW)***	***UCAP (MW)***	***Baseline End Date***	***Notes***
Adam Wind	Wind	Contract	6		7/31/2025	
Cerro Gordo	Wind	Contract	42		-	(1)
Crystal Lake I	Wind	Contract	150		6/30/2039	
Endeavor II	Wind	Contract	50		6/30/2039	
English Farms	Wind	Owned	170		-	
Flying Cloud Wind Farm	Wind	Contract	43.5		12/31/2028	
Franklin County Wind	Wind	Owned	99		-	
Golden Plains	Wind	Owned	200		-	
Hancock	Wind	Contract	98		-	(2)
Hardin Hilltop (West Jefferson)	Wind	Contract	14.7		5/27/2027	
Richland	Wind	Owned	130		-	(3)
Turtle Creek	Wind	Contract	200		12/31/2034	
Upland Prairie	Wind	Owned	300		-	
Windom/Bingham	Wind	Contract	15		6/21/2021	
Whispering Willow East	Wind	Owned	200		12/31/2034	
Whispering Willow North	Wind	Owned	200		-	

All owned baseline end dates are for modeling purposes only, and not a retirement commitment by IPL.

Notes:

1) IPL currently has a PPA with the Cerro Gordo wind farm, with an assumed repowering June 1, 2021.
2) Hancock wind farm is assumed to undergo a repowering June 1, 2021.
3) Richland wind farm, currently in-service, was modeled with a commencement date in September 2020.

In addition to the thermal and wind resources, IPL also has other contracts and demand response ("DR") programs, including a residential air conditioning direct load control ("DLC") program and large commercial interruptible programs.[11] Transactions with the MISO market or bilateral transactions for zonal resource credits ("ZRCs") also impact the portfolio. For example, [redacted]. Typically, these capacity sale/purchase transactions are performed on a short-term basis. A summary of these other capacity resources and contracts is shown in Exhibit 3.3.

Exhibit 3.3 IPL Other Capacity Resources and Contracts

Name	***Fuel Type***	***Ownership Type***	***Capacity in Aurora (MW)***	***UCAP (MW)***	***Baseline End Date***	***Notes***
BTMG Bio	Bio	Contract	1.056	[redacted]	-	
BTMG Hydro	Hydro	Contract	38.48		-	
BTMG Solar	Solar	Contract	20.31		-	
Dubuque Solar	Solar	Owned	6.2		-	
Marshalltown Solar	Solar	Owned	1.25		-	
BTMG Wind I	Wind	Contract	105.09		-	
BTMG Wind II	Wind	Contract	126.83		-	
DAEC	Nuclear	Contract	586.9		12/31/2020	(1)
ZRC Sales	-	Contract	-		[redacted]	(2)
IPL DLC	DSM	Owned	32.3 to 3.2		12/31/2032	(3)
IPL Interruptibles	DSM	Owned	225-291		-	(4)*

Notes:

1) Duane Arnold Energy Center is a nuclear facility from which IPL contracts energy. This contract was terminated effective October 1, 2020 and was reflected in the modeling as ending at the end of 2020. Capacity shown represents multiple owners and does not reflect IPL's take.

2) [redacted]

3) Direct Load Control ("DLC"), such as the residential air-conditioning switch program, is a type of demand response. The capacity expressed in the table reflects the peak capacity for demand response, available during the summer months only. DR is accounted for on the supply-side for resource adequacy, under current MISO planning assumptions.

4) Large-scale commercial interruptibles contribute towards resource adequacy on the supply-side, under current MISO planning assumptions. The capacity available for demand response varies monthly, from 225 MW to 291 MW over the course of a year. As the resource directly impacts demand, the UCAP level is higher due to scaling for losses and reserve margin.

[11] Interruptible load is the portion of the utility's load that can be curtailed in adverse conditions, such as high demand. IPL Interruptible services were modeled as DR resources in Aurora, available to be called upon during emergency conditions (simulated through a high energy price).

3.1.2. Demand Forecast

IPL serves direct residential, commercial, and industrial customers along with cooperative load, which makes up the utility's native load. Load is expected to increase modestly from 2020 through 2040, except for a wholesale contract expiring in 2026 that results in a single-year load decrease. The forecast is summarized in Exhibit 3.4.

Exhibit 3.4 IPL Load Forecast (Baseline Assumptions)

Year	***Internal Peak (MW)***	***Internal Energy (GWh)***	***Load Factor (%)***	***Interruptible Load with Distribution Losses (MW)***	***Peak Change (%)***	***Energy Change (%)***	***MISO Coincident Peak (MW)***
2020	2,970	16,045	61.7%	288	-	-	2,884
2021	2,969	16,080	61.8%	288	-0.01%	0.22%	2,883
2022	2,960	16,070	62.0%	288	-0.32%	-0.06%	2,874
2023	2,951	16,093	62.2%	288	-0.29%	0.14%	2,866
2024	2,968	16,265	62.5%	288	0.58%	1.07%	2,882
2025	2,980	16,004	61.3%	288	0.40%	-1.60%	2,894
2026[12]	2,831	15,633	63.0%	288	-5.01%	-2.32%	2,749
2027	2,839	15,730	63.2%	288	0.29%	0.62%	2,757
2028	2,849	15,846	63.5%	288	0.33%	0.74%	2,766
2029	2,864	15,939	63.5%	288	0.54%	0.59%	2,781
2030	2,877	16,046	63.7%	288	0.45%	0.67%	2,793
2031	2,888	16,144	63.8%	288	0.41%	0.61%	2,805
2032	2,900	16,235	63.9%	288	0.40%	0.56%	2,816
2033	2,912	16,329	64.0%	288	0.43%	0.58%	2,828
2034	2,926	16,406	64.0%	288	0.47%	0.47%	2,841
2035	2,939	16,494	64.1%	288	0.43%	0.54%	2,853
2036	2,951	16,579	64.1%	288	0.42%	0.52%	2,865
2037	2,958	16,640	64.2%	288	0.22%	0.36%	2,872
2038	2,966	16,704	64.3%	288	0.28%	0.38%	2,880
2039	2,968	16,705	64.3%	288	0.06%	0.01%	2,881
2040	2,968	16,712	64.3%	288	0.00%	0.04%	2,882

As a member of the MISO market, IPL must demonstrate its ability to meet demand, plus a planning reserve margin, at the time of MISO's system peak. MISO Coincident Peak is estimated as a percentage of IPL's internal net demand, where historically, this percentage is approximately 97.1%.

Given the growing importance of distributed energy resources ("DER") and energy efficiency ("EE") for managing supply-demand of energy, it was important to explicitly define the underlying projections of DER and EE in the data provided by IPL. The forecast incorporates the following:

12 The drop of load in 2026 is due to the expiration of a wholesale power contract.

- The modeling assumes IPL's 2019-2023 Energy Efficiency Plan is implemented through 2023; however, replacements for EE measures or continuation of the existing EEP program are not assumed after the program ends; and
- Customer-owned distributed energy resources ("DERs") are expected to grow over time, and DERs result in a reduction of utility load, assuming there is insufficient aggregation of DERs to be recognized as a supply-side resource.[13] IPL and CRA worked to define a set of customer-owned distributed solar and solar plus storage trajectories, based on reasonable expectations of DER penetration. Baseline expectations for customer-owned distributed generation are incorporated into IPL peak and energy assumptions for supply-demand accounting. Section 11.4 of the Appendix contains the scenario-specific customer-owned DER trajectories.

[13] Note that for modeling purposes, however, CRA modeled customer-owned DERs as generation resources in Aurora, in order to reflect hourly generation and charging/discharging profiles.

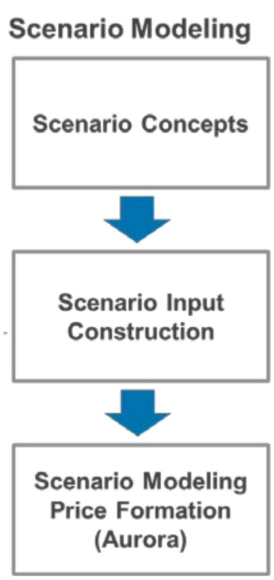
4. Planning Scenarios

4.1. Overview and Development of Planning Scenarios

Resource planning scenarios can be defined as integrated sets of assumptions about potential future market conditions and outcomes that are generally independent of IPL's portfolio decisions, but significantly important to future portfolio performance. Key scenario drivers include major policy changes (e.g. carbon regulation), commodity price trajectory changes (e.g. different gas prices due to changes in the resource base, production costs, or shifts in gas demand), technology changes (e.g. different cost trajectories for emerging generation resources), or supply-demand imbalances (e.g. changes in electricity demand as a result of customer behavior or policy). Analyzing expected future portfolio performance based on alternative sets of assumptions for such drivers makes resource planning more robust to future uncertainties. Furthermore, by assembling future scenarios into storylines with specific changes in input assumptions, portfolio performance can be better understood in relation to the major drivers.

IPL and CRA structured a scenario development process that involved: (i) defining scenario concepts; (ii) developing a set of internally consistent inputs for each scenario; and (iii) performing power market modeling in Aurora to evaluate the MISO market implications and resulting price formation.

Exhibit 4.1 Scenario Modeling Methodology



As a first step, IPL and CRA formulated assumptions around an initial reference case set of market drivers, called the "Continuing Industry Change" scenario. These market drivers relied heavily on WoodMac commodity price and technology cost forecasts, supplemented by CRA's MISO market model in Aurora.

In addition to this scenario, CRA and IPL also developed four alternative scenario concepts, each attempting to evaluate a series of risks relevant to the Clean Energy Blueprint process. The team aimed to develop a range of themes that would cover key risks and allow for a robust view of a range of potential market futures. After defining the scenario concepts, IPL and CRA worked to translate the scenario themes into specific assumptions for the key inputs of load, carbon price, natural gas price, coal price, and capital costs for new resource options.

Four additional scenario concepts were developed by stakeholders to address additional themes desired by the external stakeholder groups. The stakeholder scenarios generally modified one of the five existing scenario narratives (e.g. lower gas price, higher carbon price, higher or lower transmission interconnection costs). The five scenarios created by IPL and CRA are defined in Exhibit 4.2, with more detailed input assumptions provided in Exhibit 4.3; the four scenarios developed by stakeholder groups are outlined in Exhibit 4.4, with key changes to the core scenarios are identified in blue.

Exhibit 4.2 Core Planning Scenario Definitions

Scenario	Description	Core Scenario Inputs/Drivers	Secondary Changes	Risks Addressed
Continuing Industry Change	The fleet evolution trends of the past decade continue, and utility-stated emissions reductions targets are broadly met within the modeling.	• Low gas prices compete with improvements in renewable technology costs		• Low market price outlook requires careful portfolio management
Advanced Customer Technology	Widespread deployment of end-use generation and efficiency technologies drive customer independence from central-station generation	• Reduction in MISO load • Change in load shape based on high DG penetration	• Reserve margin requirements increase • Low solar capital costs	• Demand reduction from increased EE/DER adoption
Market Stagnation	Decline in economic outlook reduces expected environmental regulation and results in a flat load growth environment	• Reduction in MISO load • Low natural gas commodity prices	• Fewer coal retirements • Coal commodity prices higher	• Market prices don't support heavy renewable investment
New Regulation	Increased environmental regulation on the electric sector manifests via a price on CO_2 emissions (could be representative of regulatory policies or combinations of policies associated with regulating CO_2 emissions), driving supply-side changes	• CO_2 price on electric sector carbon emissions	• Lower renewable tech costs • Increase in natural gas commodity prices • Lower capacity accreditation for solar PV	• Portfolio exposed to new market risks due to CO_2 price • Capacity accreditation risks for solar resources
Electrification and Economy-Wide Carbon Limit	Increased environmental regulation manifests as a cap on CO_2 emissions that affects all sectors of the economy, driving shifts in end-use demand & supply options	• Volumetric limit on emissions • Increase in MISO load • Change to load shape based on economy-wide electrification • Higher gas price	• Lowest capacity accreditation for PV • Lower renewable tech costs	• High levels of environmental regulation on carbon-emitting fleet • High load growth

Exhibit 4.3 Core Planning Scenario Parameter Assumptions

Category	Driver	Continuing Industry Change "CIC"	Advanced Customer Technology "ACT"	Market Stagnation "MS"	New Regulation "NR"	Electrification & Economy-Wide Carbon Limit "EECL"
Fuel Prices	Natural Gas Price	WM No Carbon	WM No Carbon	WM No Carbon -10%	WM Carbon	WM Carbon +10% trending to AEO Low Resource
	Coal Price	WM No Carbon	WM No Carbon	WM No Carbon +10%	WM Carbon	WM Carbon
Load	MISO Load	MTEP Base	MTEP Low + Aggressive DER + Load Shape Change	MTEP Limited Fleet Change	MTEP Base	National Lab Deep Decarbonization + Load Shape Change
Generator Costs	Thermal Costs[14]	WM Base	WM Base	WM Base	WM Base	WM Base
	Solar Costs[15]	WM Base	WM Low	WM Base	WM Low	WM Low
	Wind Costs[16]	WM Base	WM Base	WM Base	WM Low	WM Low
	Battery Costs[17]	WM Base	WM Base	WM Base	WM Low	WM Low
	Network Upgrade Costs[18]	Expected Growth	Expected Growth	Slow Growth	Rapid Growth	Rapid Growth
Regulatory	MISO Emissions	No Carbon Price	No Carbon Price	No Carbon Price	WM Carbon Price	Emission Caps
Market	MISO Reserve Margin	8.9%	9.4%	8.9%	9.4%	9.9%
	MISO Energy Prices	Aurora Output	Aurora Output	Aurora Output	Aurora Output	Aurora Output
	MISO Capacity Prices	WM No Carbon Capacity Price	WM No Carbon Capacity Price	WM No Carbon Capacity Price	WM Carbon Capacity Price	WM Carbon Capacity Price
	PV Capacity Credit[19]	50% --> 30% (summer)	50% --> 30% (summer)	50% (summer)	50% --> 30% (summer)	50% --> 20% (summer)
	Planned Retirements	Planned / Announced	Planned / Announced	Fewer coal retirements	No MISO nuclear retirements	No MISO nuclear retirements

[14] Gas-fired option (CC and peaker) capital costs are taken from WoodMac H1 2019 No Carbon Case Iowa projections.

[15] Scenario-specific solar capital costs are derived from a combination of WoodMac H1 2019 No Carbon Case Iowa projections, which are provided for 150 MW and 20 MW sizes. The utility-scale solar PV costs for "WM Base" take WM capital costs at the 20 MW size, which is most reflective of the costs currently observed by IPL and CRA for utility-scale projects based on direct project experience and public utility filings. "WM Low" takes a 50:50 blend of 150 MW:20 MW costs, a DC-to-AC ratio of 1.3 is assumed.

[16] Wind costs are derived from WoodMac H1 2019 No Carbon Case Iowa projections, where "WM Low" represents WM onshore wind capital costs and "WM Base" applies a 10% adder, informed by IPL and CRA's market knowledge.

[17] Battery costs are derived from WoodMac's bottoms-up "U.S. Front-of-the-Meter Storage System Price Model" (WoodMac H1 2019). GTM Research estimates project development costs, not included in the pricing model, can make up of costs. "WM Base" battery costs apply a adder and "WM Low" takes the WM costs as given. Cost declines post-2024 follow the battery capital cost declines assumed by NREL *ATB 2019.*

[18] IPL and CRA developed three different trajectories for transmission interconnection costs, given significant uncertainty regarding future MISO backbone transmission upgrades. These assumptions are provided in the Appendix, and they were later adjusted slightly for IPL portfolio analysis based on stakeholder input and further IPL review.

[19] MISO is moving towards an effective load carrying capability ("ELCC") methodology for solar capacity credit, meaning that as net demand shifts to the evening hours, solar will be less valuable from a capacity perspective. Recent modeling as part of the Renewable Integration Impact Assessment ("RIIA") initiative suggests credit for solar could reduce to the 30%-20% range over time, as solar penetration grows above 50 GW and towards 90 GW, numbers consistent with the range of outcomes observed in IPL's scenario modeling. See June, 2020 RIIA analysis: https://cdn.misoenergy.org/20200626%20RIIA%20Item%2003%20Resource%20Adequacy%20Siting%20and%20Expansion%20Sensitivity454963.pdf

Exhibit 4.4 Stakeholder Requested Scenario Parameter Assumptions

Category	Driver	IEC/ELPC/SC Alternative #1 "IEC-1"	IEC/ELPC/SC Alternative #2 "IEC-2"	LEG Alternative "LEG"	OCA Alternative "OCA"
Based on Scenario		Continuing Industry Change	New Regulation	Continuing Industry Change	Electrification & Economy-Wide Carbon Limit
Fuel Prices	Natural Gas Price	WM Carbon	WM No Carbon	WM No Carbon	WM No Carbon
Fuel Prices	Coal Price	WM Carbon	WM No Carbon	WM No Carbon	WM Carbon
Load	MISO Load	MTEP Base	MTEP Base	MTEP Base	National Lab Deep Decarbonization + Load Shape Change
Generator Costs	Thermal Costs	WM Base	WM Base	WM Base	WM Base
Generator Costs	Solar Costs	WM Lowest[20]	WM Lowest	WM Base	WM Low
Generator Costs	Wind Costs	WM Low	WM Low	WM Base	WM Low
Generator Costs	Battery Costs	WM Low	WM Low	WM Base	WM Low
Generator Costs	Network Upgrade Costs			Extended High Costs w/ Point-to-Point Costs[22]	Rapid Growth
Regulatory	MISO Emissions	PacifiCorp IRP[23]	No Carbon Price	No Carbon Price	Emission Caps
Market	MISO Reserve Margin	9.4%	8.9%	8.9%	9.9%
Market	MISO Energy Prices	Aurora Output	Aurora Output	Aurora Output	Aurora Output
Market	MISO Capacity Prices	MISO cap price not higher than 50% of CONE	MISO cap price not higher than 50% of CONE	WM 2021 Price with 2.25% Escalation	WM Capacity Price
Market	PV Capacity Credit	50% --> 30% (summer)	50% --> 30% (summer)	50% --> 30% (summer)	50% --> 20% (summer)
Market	Planned Retirements	No MISO nuclear retirements	Planned / Announced	Planned / Announced	No MISO nuclear retirements

[20] Solar cost assumptions lower than those assumed in the "WM Low" concept were recommended by some IPL stakeholders, namely the IEC, ELPC, and SC; "WM Lowest" represents WoodMac costs at the 150 MW size.

[21] Note that the network upgrade cost assumptions used in the MISO market scenario analysis are shown in the Appendix, while those used in the IPL portfolio analysis are summarized in Section 5.2.1.

[22]

[23] The IEC, ELPC, and SC jointly recommended testing a higher carbon price than the WoodMac trajectory under the Carbon Case. It was suggested that a carbon price trajectory like that used in Pacificorp's recent IRP be used. Pacificorp IRP 2019. https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf

4.2. Scenario Parameters and Assumptions

4.2.1. Major Input Assumptions: Capital Costs

The capital cost estimates for new resource options were based on projections from WoodMac. The base and low-cost estimates were informed by market data points to ensure that the assumptions reasonably approximated attainable project costs.

Technology-specific costs were developed for transmission interconnection upgrades required by MISO when new resources are interconnected to the electric grid. Given significant uncertainty in future network upgrade costs for the Western region of MISO, CRA and IPL developed a range of cost assumptions. The expectation is that MISO will identify and approve a new series of "backbone" projects to relieve the significant constraints currently present in Iowa and reduce costs from current levels, but the timing of such improvements is currently unknown. The uncertainty in the timing of such projects is reflected in the three cost trajectories, with the "Rapid Growth" costs , the "Expected Growth" trajectory and the "Slow Growth" trajectory .[24] The three trajectories used in the MISO market modeling are shown in Section 11.2 of the Appendix.[25]

4.2.2. Major Input Assumptions: Fuel and Emission Prices

The primary source for natural gas, carbon, and coal price inputs was WoodMac's North American Power & Renewables Long-Term Outlook, for the H1 2019 Federal Carbon and No Federal Carbon cases. CRA applied bases to the regional gas hubs in order to develop price forecasts for points throughout MISO, based on CRA's market modeling.[26] The highest gas price assumption, used in the Electrification and Economy-Wide Carbon Limit scenario, also incorporated the "Low Oil and Gas Resource and Technology" forecast from the Energy Information Administration's Annual Energy Outlook ("AEO") 2019.[27] The Henry Hub projections across planning assumptions are summarized on an annual basis in Exhibit 4.5.

Coal price forecasts for major regional basins were provided by WoodMac, although CRA incorporates transportation adders that vary by coal plant. The WoodMac assumptions for delivered coal prices in Iowa are shown in Exhibit 4.6. Plant-level detail for delivered fuel prices for the coal plants in IPL's portfolio was incorporated, based on actual coal contract information (see Chapter 3).

Among the planning scenarios IPL and CRA developed, a New Regulation scenario analyzes the possibility of increased regulatory pressure on the electric sector to mitigate CO_2 emissions. This is represented as a price on CO_2 that starts in , based on the WoodMac Carbon Case projections. In response to joint feedback from the IEC, ELPC, and SC, an additional scenario, the "IEC/ELPC/SC Alternative #1," also tests the sensitivity of a higher carbon price that starts earlier. This carbon price trajectory is based on PacifiCorp's

[24] Refer to "CRA_Transmission_Costs_Methodology.docx" for a summary of network upgrade cost assumptions based on MISO DPP studies.

[25] Note that after receiving stakeholder comments from LEG and jointly from IEC, ELPC, and SC and after performing additional review of market conditions, IPL adjusted the cost trajectories slightly for use in the IPL portfolio analysis. The adjusted assumptions for the portfolio analysis are summarized in Section 5.2.1.

[26] Note that CRA includes daily granularity in its dispatch modeling, so daily shapes were applied.

[27] EIA. Annual Energy Outlook (AEO) 2019. *Low Oil and Gas Resource and Technology Case*.

integrated resource planning assumptions.[28] The CO_2 prices across the modeled scenarios are summarized in Exhibit 4.7.

Exhibit 4.5 Henry Hub Price by Planning Assumption

Exhibit 4.6 Delivered Coal Price (Iowa) by Planning Assumption

[28] Pacificorp IRP 2019. https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf

4.2.3. Major Input Assumptions: MISO Load Growth

The primary source for MISO load growth assumptions was the MISO MTEP report, which develops future states-of-the-world for analysis.[29] The CRA and IPL teams used this information, with some modifications for the scenarios, as noted in Exhibit 4.2. The load scenarios and peak demand growth rates for the MISO market are summarized in Exhibit 4.8. The following adjustments were made for two of the scenarios:

- A high distributed generation ("DG") adjustment, used for the Advanced Customer Technology scenario, was created by doubling the forecasted amount of DG in the system from the MTEP Distributed and Emerging Technology future scenario;[30]
- The load trajectory used in the Electrification and Economy-Wide Carbon Limit scenario incorporates several assumptions about electricity demand growth associated with the electrification of three sectors – transportation, buildings, and industry. Most assumptions came from the NREL "Electrification & Decarbonization" (2017) Report[31] which suggests that transportation accounts for most of the incremental load growth (50%) and that the electrification of heating systems (27%) and industrial processes (23%) make up the remaining half. The peak load impacts from industrial processes and residential/commercial heating were estimated from the Electric Power Research Institute's Load Shape Library 6.0.[32] An estimation of the peak load impact from electric vehicles ("EV") is based on an indicative charging schedule, where EVs are assumed to charge predominantly during off-peak hours.

---

[29] MISO. 2018 MISO Transmission Expansion Plan (MTEP). Midcontinent Independent System Operator, Inc. https://cdn.misoenergy.org/MTEP18363505.zip. 2018.

[30] Demand side additions were increased from 3 GW to 6 GW of DG system-wide by 2032.

[31] NREL. Electrification & Decarbonization: Exploring US Energy Use and Greenhouse Gas emissions in Scenarios with Widespread Electrification and Power Sector Decarbonization. July 2017

[32] EPRI. Load Shape Library 6.0. Electric Power Research Institute. http://loadshape.epri.com/aboutus#. 2019.

Exhibit 4.9 displays the hourly charging profile, adapted from a DOE-funded study of over 10,000 EV charging systems across the U.S.[33]

Exhibit 4.8 MISO Load Scenarios

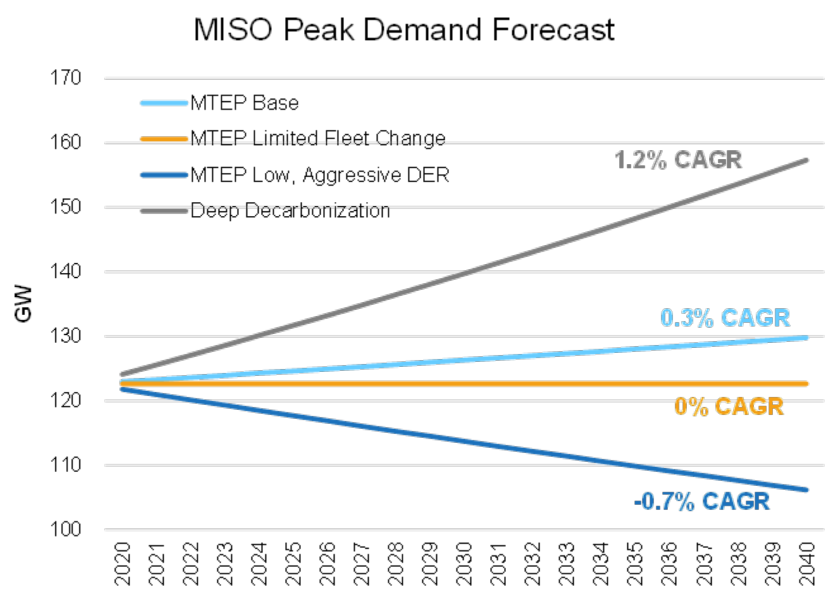
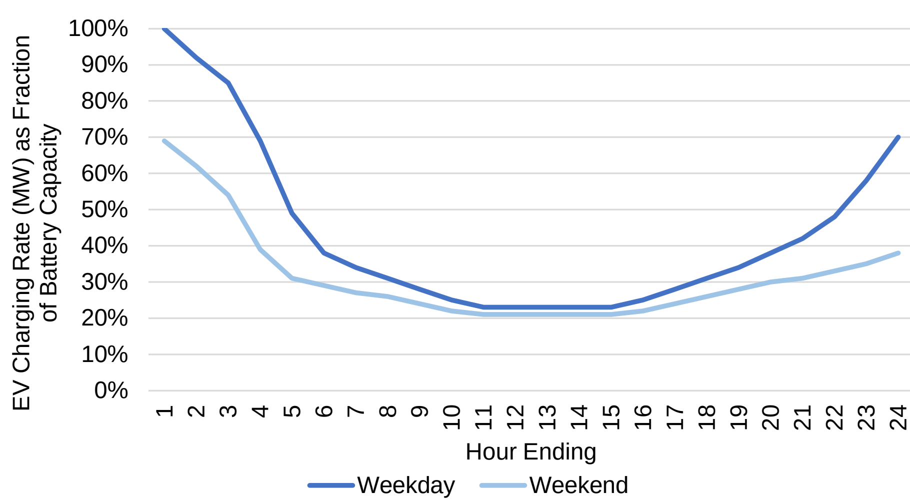


Exhibit 4.9 Electric Vehicle Charging Schedule



33 Schey, Scoffiel, Smart (2012). "A First Look at the Impact of Electric Vehicle Charging on the Electric Grid in the EV Project." EVS26 International Battery, Hybrid and Fuel Cell Electric Vehicle Symposium. https://www.energy.gov/sites/prod/files/2014/02/f8/evs26_charging_demand_manuscript.pdf.

4.3. Price Formation Modeling Approach

CRA used Aurora's long-term capacity optimization logic to develop a view on capacity expansion and retirements under each distinct scenario for the entire MISO footprint. This functionality allows the model to retire units that are no longer competitive and to select candidate resource options to add to the fleet when they are economic. CRA deployed Aurora's[34] traditional long-term portfolio optimization logic, which performs an iterative simulation to evaluate retirements and new builds before finding a solution that converges on a preliminary least-cost outcome.[35] The analysis results in a long-term projection of regional capacity expansion and retirements, which are then used to produce a full forecast of market prices across MISO. The next section provides a summary of major market outputs from the MISO simulation, while Section 11.3 in the Appendix provides additional detail on specific modeling assumptions associated with the long-term market analysis.

4.4. Scenario Modeling Results

4.4.1. Summary of Power Market Analysis: Retirements, New Builds, and Generation Projections

The market scenario simulations resulted in a diverse mix of future outcomes for capacity additions, retirements, and generation mix over time. Exhibit 4.10 presents a summary of total nameplate capacity and total generation by fuel type across MISO by 2040, and Exhibit 4.11 provides comparative annual generation by fuel type summaries over time.[36] The following are the key observations:

- All scenarios include a significant shift away from coal and towards renewables. Coal generation is projected to retain the highest share of the total by 2040 in the Market Stagnation scenario (26%), while scenarios with carbon pricing or restrictions result in coal's generation share falling to less than 10%. Cumulative coal retirements between 2020 and 2040 are projected to be between 25 GW and 53 GW across the scenarios.
- Total renewable (wind, solar, and hydro) generation is projected to be between 38% (Market Stagnation) and 64% (IEC-1), with most scenarios having over 50% penetration on an energy basis. Significant renewable capacity additions are projected, especially in the scenarios with carbon prices and electrification-driven load growth.
- The share of natural gas generation across the market is projected to be between approximately 20% and 35% across scenarios by 2040. Scenarios with higher carbon prices and natural gas prices tend to have lower gas generation, while the CIC and OCA scenarios have the highest gas generation.

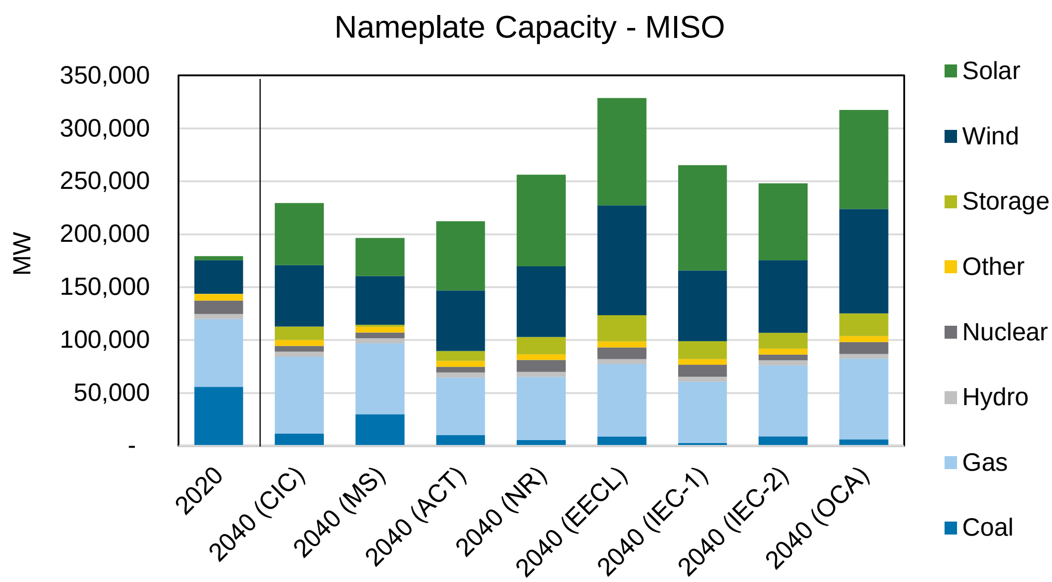
---

[34] Aurora analysis was performed using CRA's Aurora model, which includes the core database provided by Energy Exemplar, the licensers of Aurora, and CRA's proprietary changes based on other market research and intelligence. While many data sources rely on MISO and utility reports, the model is not identical to the MISO MTEP models IPL uses in PROMOD simulations.

[35] Note that Section 11.3 of the appendix summarizes small modifications that are made to the preliminary least-cost optimization outputs.

[36] Note that LEG's proposed scenario only changed IPL-specific assumptions, namely around transmission interconnection costs, point-to-point transmission service costs, and capacity prices, and was otherwise based on the CIC scenario for MISO market conditions. Therefore, these graphics do not include a separate MISO market outcome for LEG.

Exhibit 4.10 MISO Capacity and Generation Mix 2040 by Scenario



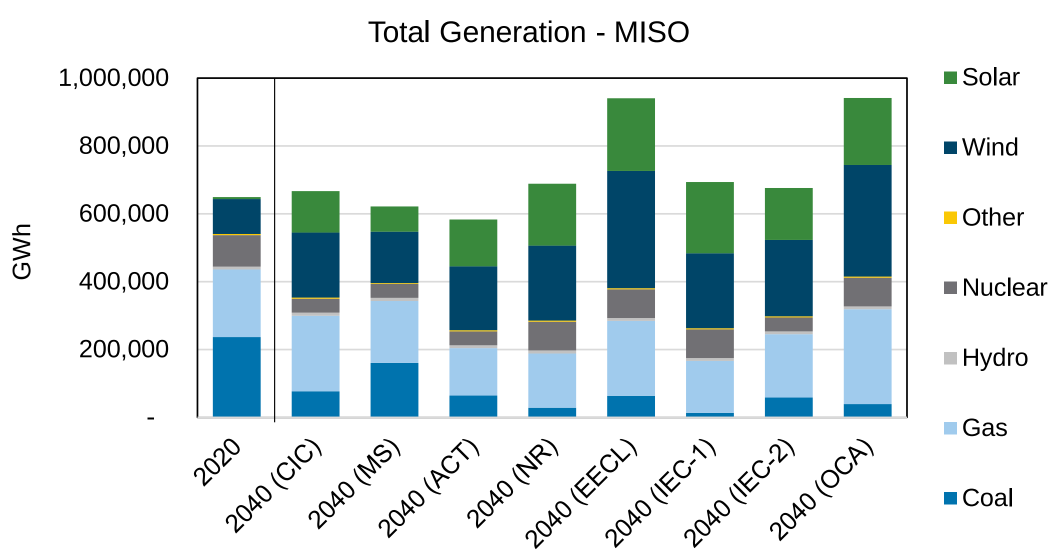
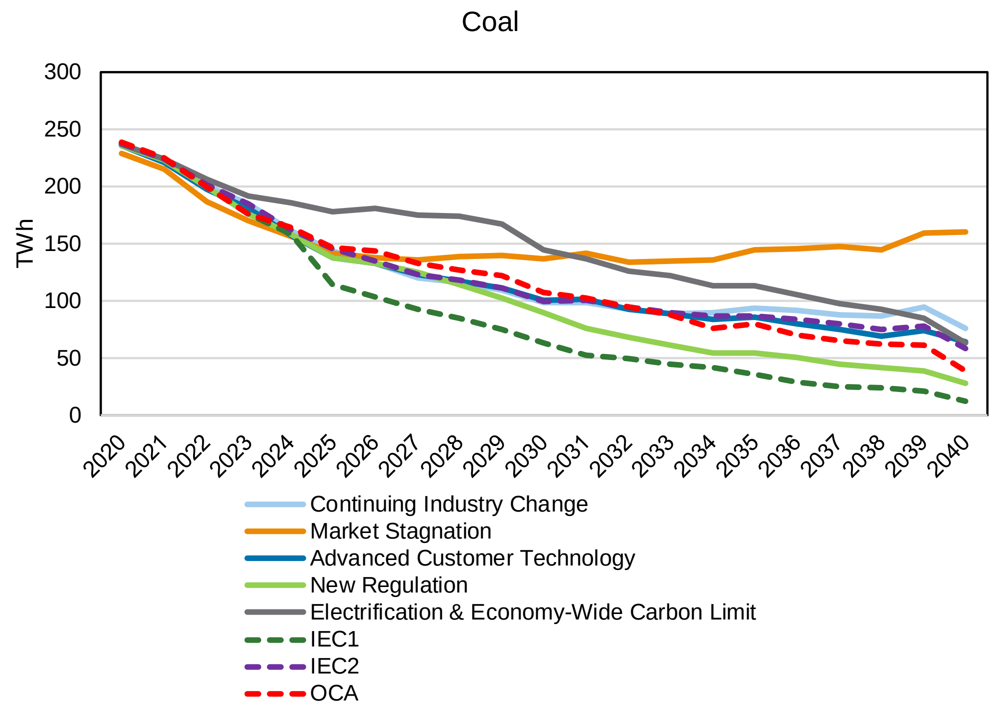
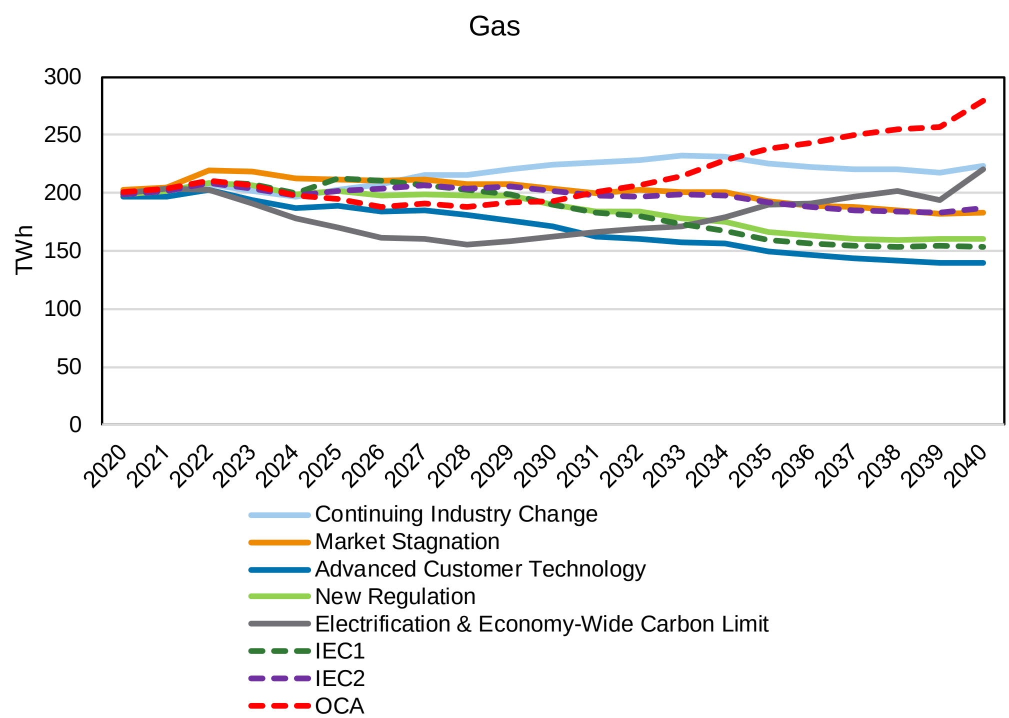
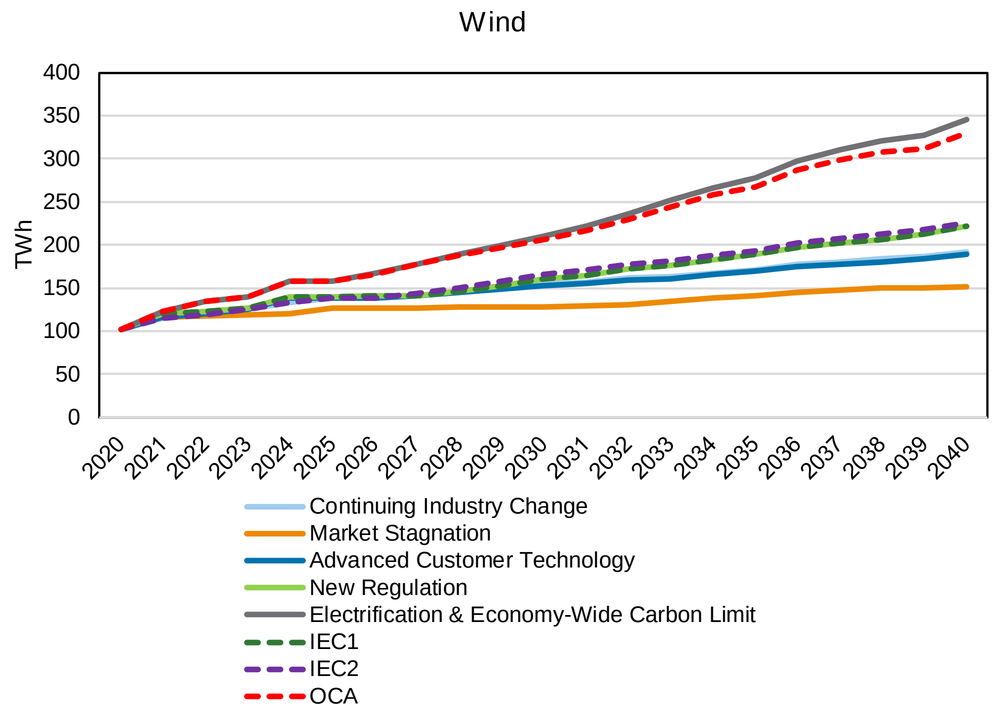
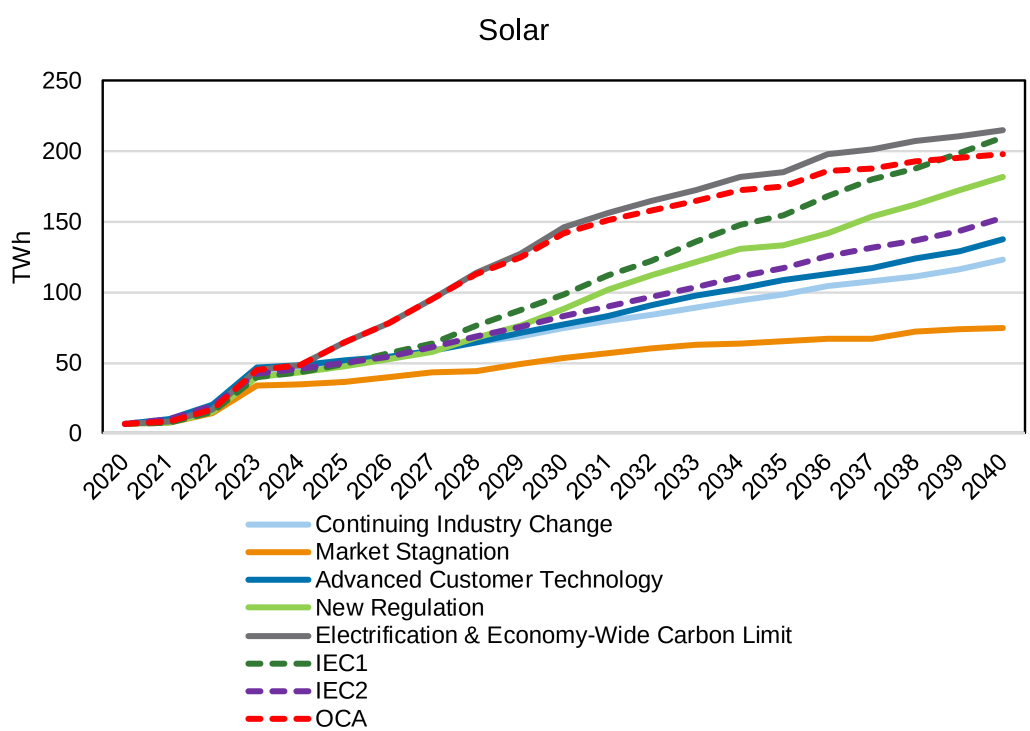


Exhibit 4.11 Generation by Fuel Type Across Scenarios






Wind
TWh
400
350
300
250
200
150
100
50
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
Continuing Industry Change
Market Stagnation
Advanced Customer Technology
New Regulation
Electrification & Economy-Wide Carbon Limit
IEC1
IEC2
OCA


Solar
TWh
250
200
150
100
50
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
Continuing Industry Change
Market Stagnation
Advanced Customer Technology
New Regulation
Electrification & Economy-Wide Carbon Limit
IEC1
IEC2
OCA

4.4.2. Scenario Price Comparisons

Power market prices are influenced most significantly by the price of natural gas, the price of carbon, and the capacity mix in the market. Across all scenarios, the price spread is expected to widen after the first seven years of the forecast period, as a result of changes in fuel prices and carbon price assumptions, as well as the evolution of the generating fleet. This is shown in Exhibit 4.12, which presents all hours, peak, and off-peak price projections over time for MISO Zone 3.

In addition to the annual average price ranges, the scenarios have different hourly shapes, primarily driven by the amount of renewable capacity entering the system and the type of generating resource that is marginal at any given point in time. More solar additions tend to lower relative prices during the mid-day period and shift the summer peak later in the day. The hourly price profiles for winter and summer months are summarized in Exhibit 4.13.

Exhibit 4.12 MISO Zone 3 All Hours, On-Peak, and Off-Peak Electricity Price

Zone 3 (Iowa) Electricity Price - On Peak

Zone 3 (Iowa) Electricity Price - Off Peak

Exhibit 4.13 Hourly Price Profiles for Winter and Summer, Across Scenarios

Summer

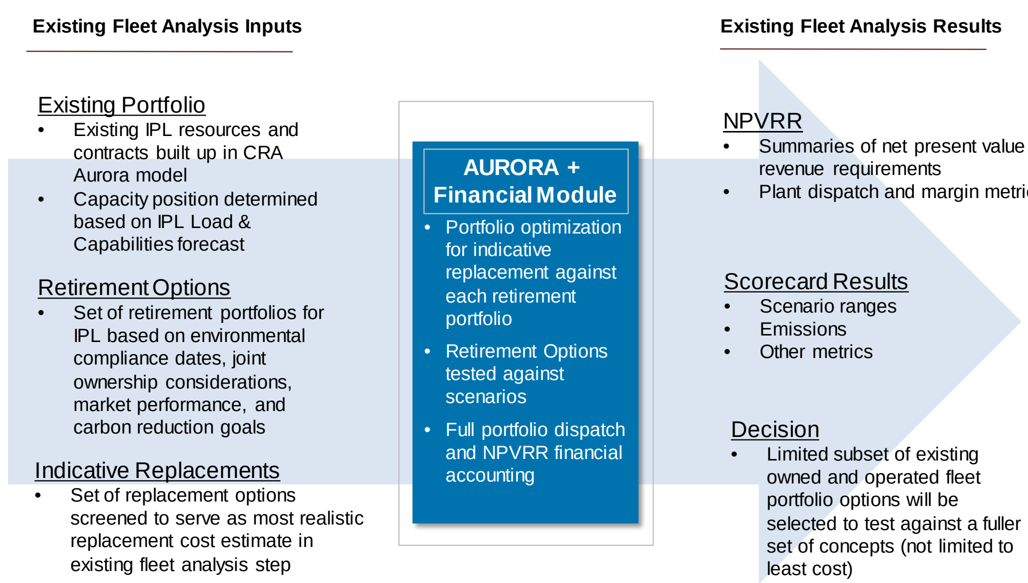
5. Existing Fleet Options Portfolio Development – Phase 1

As discussed in Chapter 2, IPL and CRA developed a two-phased approach for analyzing the portfolio questions associated with IPL's existing fleet of owned and operated resources and potential new resources over time. Central to that approach was the development of an initial set of portfolios for the existing fleet of owned and operated resources, which represent feasible strategies for IPL to meet its capacity obligation over the long-term planning horizon, structured around different near-term and long-term portfolio retirement decisions. The Phase 1 portfolio analysis can be broken down into three stages, as depicted in Exhibit 5.1:

1. Input development: Specification of existing portfolio; identification of options for the existing portfolio, including timeline and cost implications associated with specific retirement dates; and identification of replacement resource options that are available over time.
2. Portfolio dispatch simulation in Aurora with financial cost accounting;
3. Review of results, including assessment of portfolio costs and other dashboard metrics, to drive towards a refined subset of preferred portfolio pathways for further study in Phase 2.

The remainder of this chapter details the process for defining the Phase 1 existing fleet option portfolios, based on a set of assumptions about IPL's supply, demand, and technology costs and parameters for viable resource options. This chapter also details the specific portfolios that were optimized under two distinct planning scenarios, Continuing Industry Change and New Regulation.[37] Chapter 6 describes the results of the Phase 1 analysis, including portfolio performance outputs and revenue requirement expectations under both pathways.

Exhibit 5.1 Phase 1 Retirement Analysis Process Flow Chart



[37] Through the collaborative process, IEC, ELPC, and SC jointly inquired about conducting a replacement portfolio optimization analysis on more than one scenario. In response, IPL performed a portfolio optimization on the New Regulation scenario in addition to analysis performed on the initial Continuing Industry Change Scenario. These two scenarios provided a range of capital costs (inclusive of transmission interconnection) for new renewables.

5.1. Portfolio Development Approach

As IPL is a load-serving entity in the MISO market, IPL must demonstrate its ability to meet a sufficient planning reserve margin, with respect to the base load forecast for the MISO coincident peak. Under baseline planning assumptions, IPL is expected to have enough generation capacity to meet its capacity obligation until [redacted] (see the UCAP breakdown and capacity obligation under baseline, end-of-life retirement assumptions in Exhibit 5.2).

[redacted]

Exhibit 5.2 IPL Baseline Supply-Demand Balances

[redacted]

IPL developed a set of nine feasible operational pathways for its existing owned and operated fleet, consisting of various permutations of unit retirement dates and coal-to-gas conversion options as outlined in Exhibit 5.3. The existing generation units evaluated were the following:

- Lansing Unit 4
    - Retirement in 2037
    - Retirement in 2021
- Burlington Generating Station
    - Gas conversion of Unit 1 in 2021 to 85 MW, 110 MW, or 200 MW sizes; Retirement of Unit 1 and Gas CT's in 2026
    - Retirement of Unit 1 and Gas CT's in 2021
- Prairie Creek Units 3 and 4
    - Gas conversion of Unit 3 in 2025; Retirement of Units 3 and 4 in 2035
    - Retirement of Units 3 and 4 in 2025
- Ottumwa Unit 1
    - Retirement in 2034
    - Retirement in 2026

        - Retirement in 2030
- Emery Generation Station
    - Retirement in 2039
    - Retirement 2030

Exhibit 5.3 IPL Phase 1 Existing Resource Operational Pathway Portfolios

Portfolio Concept	Baseline	Key Near-term Decisions (Lansing, Burlington, Prairie Creek)					Retire All Alliant Operated Coal		Retire All Alliant Operated Coal + Emery CC
	1	2	3	4	5	6	7	8	9
Operational Changes by Plant:	None	Lansing Burlington *(Conversion Option 1)*	Lansing Burlington *(Conversion Option 2)*	Lansing Burlington *(Conversion Option 3)*	Lansing Burlington	Lansing Burlington Prairie Creek	by 2026	by 2030	Coal 2026 Emery 2030
Lansing 4	Retire 2037	Early Ret. (2021)	→	→	→	→	Early Ret. (2021)	→	→
Burlington 1	Gas Conversion in 2021 (85 MW), Retire in 2026	→	Convert to 110 MW Gas	Convert to 200 MW Gas	Early Ret. (2021)	→	Gas Conversion in 2021 (85 MW), Retire in 2026	→	→
Prairie Creek 3&4**	Gas Conversion in 2025 (unit 3), Retire in 2035	→	→	→	→	Early Ret. (2025)	Gas Conversion in 2025 (unit 3), Retire in 2035	→	→
Ottumwa 1	Retire in 2034	→	→	→	→	→	Early Ret. (2026)	Early Ret. (2030)	Early Ret. (2026)
Emery CC	Retire in 2039	→	→	→	→	→	→	→	Early Ret. (2030)

The construction of full portfolios under these operational pathways was performed using the portfolio optimization feature in Aurora. The process involved evaluating the economics of a range of new resource options against IPL's peak requirements and other modeling constraints for each of the nine existing resource operational pathway portfolios.[38] Additional detail on the constraints associated with the portfolio optimization analysis is provided in Section 11.5 of the Appendix. The optimization analysis developed portfolio concepts, optimized under Continuing Industry Change and New Regulation scenarios.[39]

5.2. Capacity Replacement Options

IPL considered a range of replacement capacity options, such as utility-owned generating resources, demand side management ("DSM") measures, and market or bilateral transactions for capacity, which could enable IPL to meet its long-term capacity obligation. This section provides additional information regarding the replacement options considered, which included:

---

[38] IPL coordinated with ITC Midwest at a high level on transmission topics related to potential unit retirement impacts.

[39] It is important to note that the New Regulation scenario assumptions include different expectations for customer-owned distributed generation ("DG") and customer-driven incremental energy efficiency measures. Therefore, the load obligation is different under the two scenarios. Detailed information on the assumed customer-owned DG across scenarios is provided in Section 11.4 of the Appendix.

- Solar PV;
- Stand-alone lithium-ion battery storage;
- Solar PV, paired with lithium-ion battery storage, at a 4:1 pairing ratio of solar:storage nameplate capacity;
- Onshore wind;
- Natural gas peaker of frame type;
- Natural gas combined-cycle;
- IPL-owned distributed energy resources (“DER”) – stand-alone storage, and paired solar and storage – sited at customer locations;
- Energy efficiency programs;
- Demand response programs; and
- Capacity purchases.

5.2.1. Utility-Owned Resources

Utility-Scale Generation Resources

The main technology assumptions for utility-owned resources are provided in Exhibit 5.4. The contribution to IPL’s capacity obligation (stated as a percentage of nameplate installed capacity), typical block size of additions, and maximum limits on capacity that can feasibly be built in a single planning year were also specified in the optimization analysis.

Capital cost projections for new resource options were based on the WoodMac 2019 H1 No Federal Carbon Case estimates, supplemented by adjustments made by the IPL and CRA teams based on market insights. Market insights can be obtained in a number of ways, including Request for Proposals, CRA proprietary data, actual project data or market research scans. The relatively strong midwestern market for solar provides opportunities to gauge reasonable costs, avoiding the need to identify specific projects in this resource planning process. The unsubsidized capital cost projections for each technology are provided in Exhibit 5.5.[40]

[40] Note that the analysis incorporates the relevant investment tax credit (“ITC”) and production tax credit (“PTC”) benefits available for the renewable technologies. The tax benefit was represented as a reduction in capital cost, due to potential contributions from tax equity partners. The tax equity finance accounting is summarized in greater detail in Chapter 6.

Exhibit 5.4 Utility-Owned Resource Options: Operational Assumptions

Technology	***Operational Parameters and Capacity Credit Assumptions***	***Block Size***	***Max Install per Year***
Solar PV	24% capacity factor with 0.5% degradation per year;[41] declining capacity credit from 50% to 50/30/20% in 2040 (scenario-dependent)	25 MW	1 GW
Wind	45% capacity factor; 15.7% capacity credit; modeled with nodal discount to ALTW LMP[42]	100 MW	1 GW
Stand-alone Storage	Lithium-ion battery with 87.5% roundtrip efficiency, four-hour storage; 98% capacity credit; additional ancillary services benefit approximated[43]	25 MW	250 MW
Paired Solar and Storage	4:1 pairing ratio (40 MW solar, 10 MW battery)	50 MW	1 GW
Gas Peaker	Modeled as a simple cycle GT Frame with 9,700 Btu/kWh heat rate; 95% capacity credit	250 MW	1 GW
Gas CC	Modeled as 1x1 configuration with 6,600 Btu/kWh heat rate; 95% capacity credit	400 MW	800 MW

[41] This degradation assumption is representative of an all-in degradation rate on the output of the solar system. This assumption is supported by recently published literature that has been used to support the National Renewable Energy Laboratory's (NREL) solar PV models. A literature review across various solar technologies and vintages found a median degradation rate value of 0.5%/year, with the vast majority of estimates falling below 1.0%/year. In addition, Lawrence Berkeley National Laboratory published a report on empirical trends in utility-scale solar performance and PPA pricing; the report found that a sub-sample of utility-scale PV PPAs included contractual not-to-exceed degradation rates ranging from 0.25%-1.0%/year, with a sample median of 0.5%/year.
Jordan, D. and Kurtz, S. (2012). Photovoltaic Degradation Rates – An Analytical Review. NREL/JA-5200-51664. https://www.nrel.gov/docs/fy12osti/51664.pdf; Bolinger, M., Seel, J., & Robson, D. (2019). Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States – 2019 Edition. Lawrence Berkeley National Laboratory: https://escholarship.org/uc/item/336457 p.8.

[42] Wind farms in IPL's fleet have typically exhibited nodal discounts relative to the ALTW LMP; as such, a 15% discount during on-peak hours and 10% discount during off-peak hours, was accounted for new wind resources.

[43] Indicative assumptions for the ancillary services value from stand-alone storage, gas peaker, and gas CC resources were included based on CRA's recent analysis of value in the MISO market.

Exhibit 5.5 IPL-Owned Resource Options: Capital Cost Assumptions[44]

Wind Unsubsidized Costs

[44] Note that this exhibit represents capital costs prior to any accounting for transmission interconnection costs. Transmission interconnection network upgrade costs were accounted for separately, as summarized in Exhibit 5.6.

Lithium-Ion Battery Costs

IPL worked with CRA and the stakeholders to define cost trajectories for transmission interconnection network upgrades for new resources. The range of transmission interconnection costs used for the IPL-specific analysis captures the uncertainty surrounding transmission costs in the future. The technology-specific network upgrade costs, by resource type and planning scenario, are summarized in Exhibit 5.6.

Exhibit 5.6 Transmission Network Upgrade Costs by Technology Type

Solar

Wind

Thermal and Stand-Alone Storage

Distributed Energy Resources

IPL analyzed the potential for IPL-owned[45] distributed resources to provide capacity and energy to the system, along with potential benefits associated with avoided upgrades to the distribution system. DER resources may also provide additional benefits such as local reliability improvements, reduced energy line losses, and other synergies with potential customer hosts. For modeling purposes, IPL is assumed to own these non-wires alternatives, which would be sited at customer locations or other sites on the distribution system. The team determined plausible installed capacities of stand-alone storage and paired solar and storage that could provide a range of avoided distribution upgrades and related avoided costs.

For clarity and simplicity, the option for utility-owned DER was represented by tranches according to avoided distribution system cost estimates and implemented in order of high to low cost savings. The capital costs associated with DERs were modeled with the utility-scale costs for the same technology types, with an additional premium related to the smaller size. The resource tranches were modeled in Aurora, along with their cost profiles (where the avoided distribution costs have been accounted as capital cost savings), and eligible to be selected in the least-cost optimization modeling. The capacity limits and avoided distribution upgrade costs for the modeled DER tranches are listed in Exhibit 5.7.

Exhibit 5.7 IPL-owned DER Tranches: Installed Capacities and Avoided Distribution Costs

Tranche	***Avoided Costs from Distribution Upgrades***	***Stand-alone Storage***	***Paired Solar and Storage***[46]
High Dist. Deferral			
Med Dist. Deferral			
Low Dist. Deferral			

5.2.2. Demand-Side Measures

IPL's third-party DSM consultant, the Cadmus Group ("Cadmus"), conducted an analysis to determine possible energy efficiency measures (after the 2019-2023 Energy Efficiency Program ("EEP") concludes) and DR programs that IPL could pursue as load-reduction strategies. Cadmus provided detailed information about the energy and/or capacity value of the DSM measures, as well as relevant program costs to the utility. These DSM measures were organized into tranches that could ultimately be selected in the least-cost optimization modeling.[47]

[45] Note that a range of customer-owned distributed energy resources was assessed throughout the scenario development process, with a range of future penetration rates incorporated across scenarios. The specific ranges are detailed in Section 11.4.

[46] A 2:1 pairing ratio of solar:storage nameplate capacity is assumed for DERs that are sited at customer locations.

[47] IPL and CRA provided the detailed assumptions for energy efficiency and demand response tranches and relevant costs in the February 25, 2020 stakeholder meeting and in detailed spreadsheets sent to stakeholders on February 28, 2020.

Energy Efficiency

Cadmus' approach to estimate EE potential for IPL relied on the 2017 Iowa Statewide Potential Study. The potential study data, conducted by Dunsky Energy Consulting, was a ten-year study (2018-2027) that included IPL-specific technical, economic, and achievable potential results. Cadmus translated the data into technical achievable potential projections, by applying adoption rates to technical potential energy efficiency estimates, rather than solely measures economic to the utility. Cadmus grouped the EE measures into levelized cost bundles (utility cost per kWh) by year. Cadmus evaluated measures specific to low-income residential customers separately from other EE bundles, as low-income programs have different program costs and tend to be more expensive with less savings than other residential programs. Incentive and administration costs associated with the energy efficiency programs were based on IPL's current 2019-2023 EEP and mapped to the potential study data. Using the 2024-2027 technical achievable potential data, Cadmus projected the energy efficiency savings over the remaining planning horizon (2028-2040).

Applying the Iowa Technical Reference Manual hourly load shapes to annual energy savings, end-use hourly energy savings profiles were developed. Cadmus also provided typical end-of-use lifetimes; whereby, the EE measures are assumed to provide energy savings until the end of their useful lives.

CRA modeled the hourly energy savings and cost assumptions of the EE programs in Aurora by bundles, categorized by program year (e.g. three planning periods, reflective of typical utility planning timelines) and levelized cost. The resource adequacy value of EE is accounted as a reduction in peak load, and thus, IPL's capacity obligation. Exhibit 5.8 provides an illustration of the various bundles of energy efficiency over time which were candidate replacement resource options in the least-cost optimization modeling.

Exhibit 5.8 Achievable Energy Efficiency Measures[48]

Demand Response ("DR")

IPL currently operates a residential air-conditioning ("AC") direct load control ("DLC") program and a large-scale industrial interruptible program. IPL expects to begin winding down the residential AC program over the course of ten years (2024-2033), with the potential to transition to other DR measures:

- **New residential DLC programs, such as a smart thermostat "bring-your-own-thermostat" program**.[49] An estimate of the maximum number of participants for such a program was derived from the 2017 Iowa Statewide Potential Study, which estimated the saturation of homes for smart thermostats and achievable adoption rates. The per unit impacts and costs (i.e. incentives, administration, and marketing costs) were built off existing residential DLC AC program assumptions;
- **Small-scale commercial DLC program.** This promotes the direct installation of smart thermostats and DR. Cadmus developed program impacts and costs through benchmarking other utility DR potential studies and utility program data.

The DR measures above would represent about 25 MW of peak capacity by 2040. CRA modeled the first-year costs, ongoing costs, and capacity contributions from the DR programs, which were candidate options in the least-cost optimization modeling.

---

[48] The black shaded area, "2019-2023 Energy Efficiency Plan," was hard-coded into the modeled IPL demand trajectory, as the EEP program is assumed to continue as planned. The green and blue shaded areas roughly illustrate the eligible EE bundles that provide savings for a given number of years; the initial ramp-up in savings represents new EE measures adopted through the EEP program, until they gradually ramp down at the end of their useful lifetimes.

[49] IPL filed an Application for a Limited Modification of the Energy Efficiency Plan on October 15, 2020 asking for Board approval of a 3-year Smart Thermostat pilot within the Demand Response Portfolio.

5.2.3. Capacity Purchases

IPL identified three price points for bilateral short-term capacity purchases in the near-term planning period (2020-2025), based on recent experience and market insight. The option to purchase up to [redacted] of capacity in any given year was recognized as a viable strategy to fill a short-term capacity need. For the long-term planning period (2026-2040), one-year capacity purchases up to 100 MW were allowed as options to bridge a capacity gap, as existing resources and contracts come offline throughout the modeling period. To capture uncertainty in long-term capacity prices, a range of prices was modeled across the scenarios, with three stakeholder-suggested scenarios departing from the base assumption of WoodMac's MISO Zone 3 capacity prices (and a slightly different WoodMac carbon price scenario forecast). The capacity price assumptions used across scenarios are depicted in Exhibit 5.9.

As load growth, customer-owned DG, and solar PV capacity credit assumptions vary across the planning scenarios, IPL's capacity obligation is also expected to vary. From a portfolio analysis perspective, capacity purchases backfill the gap between portfolio UCAP and the scenario-specific capacity obligations; thus, capacity purchase quantities differ across planning scenarios.

Exhibit 5.9 MISO Zone 3 Capacity Pricing Assumptions

[redacted]

5.3. Phase 1 Optimization Modeling

The portfolio optimization exercise in Aurora led to the development of two different portfolios for each of the nine existing owned and operated fleet operational pathways (see Exhibit 5.3) based on optimization under the Continuing Industry Change and New Regulation scenarios. For ease of reference, the naming convention throughout this report will refer to a portfolio's operational concept by number and refer to the scenario by letter, where "a" is Continuing Industry Change and "b" is New Regulation. For example, 2a is the portfolio that retires Lansing in 2021, optimized under the Continuing Industry Change scenario assumptions.

The optimization analysis revealed the following:

- Utility-scale solar was the predominant resource selected in the modeling when capacity needs arose, with the first installations occurring in line with the drop in expected network upgrade costs. Under Continuing Industry Change, this drop occurs in 2025; under New Regulation, this drop occurs in 2023;
- In the portfolios that retire Lansing Unit 4 in 2021, [redacted] with solar additions in subsequent years (2026 in portfolios 2a through 9a; 2023 in portfolios 2b through 9b);
- In the Continuing Industry Change optimization scenario, all portfolios selected 122 MW of installed utility-owned DER standalone storage by 2030 and paired solar and storage tranches with the highest avoided distribution costs. In the New Regulation optimization scenario, lower cost assumptions for solar and storage resulted in the optimizer selecting a greater amount of utility-owned DER capacity, totaling nearly 400 MW of installed capacity by 2040;
- Lower wind costs and a drop in the transmission interconnection costs (prior to the expiration of the PTC after 2024) under the New Regulation scenario result in the selection of a limited capacity of wind installations in 2024 in the "b" portfolios;
- A varied number of DSM programs (all EE measures) were selected across all portfolio concepts, resulting in energy savings that reduce peak load by approximately 200 MW in 2040;

Exhibit 5.10 provides summary level detail of the cumulative installed capacity by resource type across the Continuing Industry Change optimized portfolios, and Exhibit 5.11 provides a summary of the cumulative installed capacity added in the New Regulation optimized portfolios. For more detail on the Continuing Industry Change and New Regulation-optimized portfolios, please refer to Section 11.6 in the Appendix.

Exhibit 5.10 Cumulative Nameplate Installations by Portfolio, Optimized under Continuing Industry Change

Exhibit 5.11 Cumulative Nameplate Installations by Portfolio, Optimized under New Regulation

Exhibit 5.12 [redacted]

[redacted]

6. Phase 1 Portfolio Analysis

6.1. Aurora Portfolio Dispatch Analysis

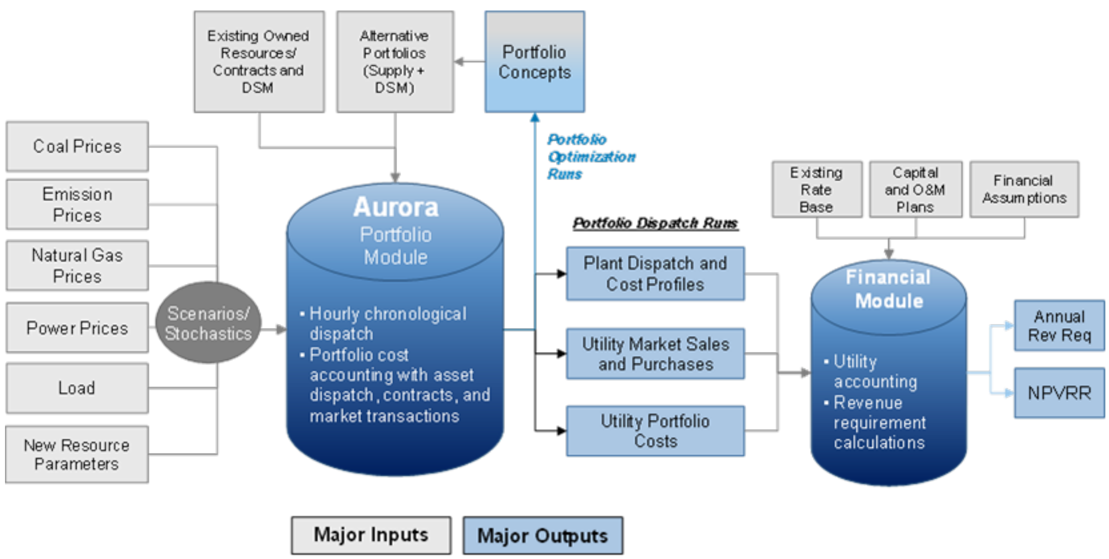
The portfolio modeling feature of Aurora enables the user to evaluate revenues and costs associated with serving demand for a fleet of owned and contracted resources. This feature combines Aurora's asset dispatch modeling capabilities with energy balancing in the broader market.[50] As the Aurora model is run, it tracks whether IPL's portfolio is short or long energy at any given time and accounts for net purchases and sales in the day-ahead energy market at MISO Zone 3 prices.

Aurora simulates the hourly chronological dispatch of energy assets and calculates all variable costs associated with:

- Dispatch of owned resources (e.g. fuel, variable operating and maintenance, startup, and emission costs);
- Revenues and costs from contracts (terms specified by IPL); and
- Revenues and costs from MISO market purchases and sales.

The general process is outlined in the left side of the flow chart in Exhibit 6.1. CRA ran the Aurora model in a standard, all-hours fashion for the modeled time period of 2020 through 2040 to evaluate all Phase 1 portfolios against all nine (IPL and stakeholder-proposed) scenarios.

Exhibit 6.1 CRA Modeling Framework



50 IPL operates within the MISO market and essentially sells all generation into the market and buys back what it needs to meet load. The Aurora model tracks this position on an hourly basis, accounting for net sales and purchases.

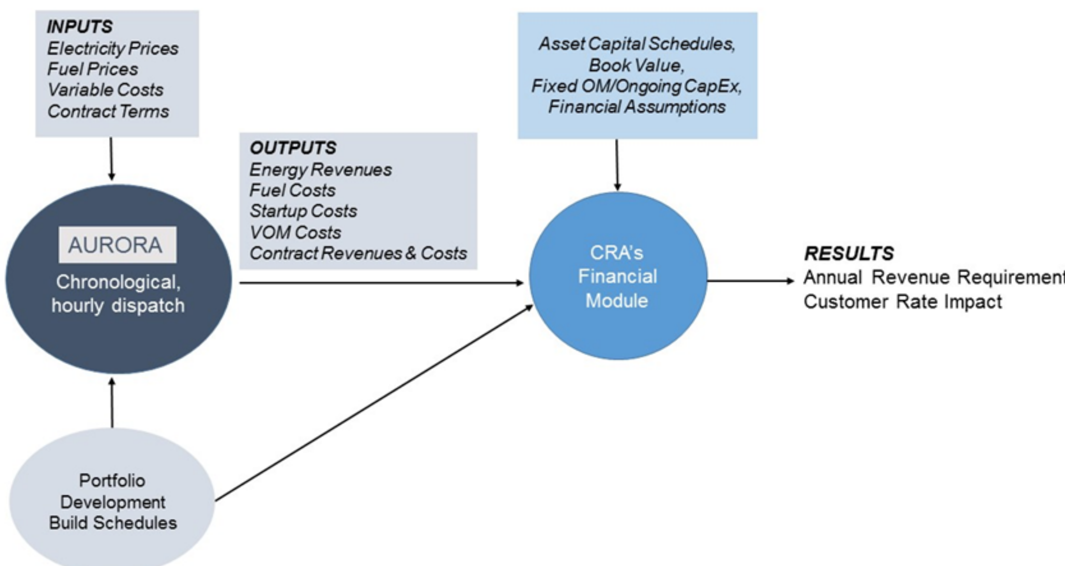
6.2. CRA Financial Module

6.2.1. Overview

CRA's financial module projects utility revenue requirements, which are made up of the following components: total variable power supply costs like fuel, emissions and variable operations and maintenance costs (all calculated within Aurora); fixed operating and maintenance costs; capital expenditures associated with IPL's fleet (new or existing) and the associated financial accounting of depreciation, taxes, and utility return on investment on all capital expenditures; and the existing book value associated with IPL's fleet and all associated financial calculations. For purposes of evaluation, the present value of these revenue requirements across time for all portfolios are recorded in the financial module. A summary of inputs and outputs to the CRA financial module is summarized in Exhibit 6.2.

IPL's core financial assumptions are shown in Exhibit 6.3. These financial assumptions utilize IPL's weighted return on equity from Docket No. RPU-2019-0001 for existing and planned new projects (defined from ratemaking proceedings and principles). CRA's financial module also accounts for the various tax treatments of existing and new resources as they relate to customer revenue requirement calculations. The financial module uses accelerated tax depreciation schedules to calculate deferred taxes for both new and existing capital. In addition to this, the model accounts for Iowa-specific tax rules around the effect of tax flowback values when existing IPL units retire.[51]

Exhibit 6.2 CRA Financial Module Inputs and Outputs



[51] Certain net book versus tax basis differences at the in-service date of the plant are flowed through to the customers' benefit. In addition, accelerated Iowa state tax depreciation in excess of book depreciation in early years of an investment create benefits for customers. Those differences eventually reverse over the book life of the asset, and if there is an early retirement, represent uncollected amounts of the flowback still remaining.

Exhibit 6.3 Core Financial Assumptions

Income Tax Rate	28.7%
Federal Income Tax Rate	21.00%
State Income Tax Rate	9.80%
Property Tax Rate	0.00%
Return on Equity (Blend of Existing and New Assets)	9.8%
Cost of Debt (Existing and New Assets)	4.34%
Equity % Rate Base	51%
Debt % Rate Base	49%
AFUDC	7.12%
After-Tax WACC	6.56%

For the resource planning analysis in the Clean Energy Blueprint, an annual revenue requirement was projected for the time period of 2020 through 2055. CRA runs its fundamental Aurora dispatch through 2040, and all revenue requirements through 2040 are calculated using actual portfolio results from Aurora. In order to properly account for the capital that is added in each portfolio, CRA runs an additional "end-effects" calculation through 2055. This extension period grows all O&M, including Aurora output, at inflation, while continuing to fundamentally calculate return on, return of, and taxes associated with capital additions. This extension period is necessary because of the way capital is recovered under a rate-based approach; the annual cost of new assets declines over time as capital is depreciated, and without accounting for later, low-cost years, the true cost of new capital additions may otherwise be overstated relative to alternatives.

6.2.2. Financial Treatment of Existing Assets

CRA's financial module considers the net book value and tax attributes of IPL's existing assets, based on capital schedules provided by IPL. The decommissioning costs for the early retirement of the thermal power plants are based on the cost of removal ("COR") estimates embedded in existing capital schedules provided by IPL. In addition, the module considers fixed O&M schedules for the existing owned assets. The module assumes that all existing capital, as well as any new project investments, earn a return of and on the investment through the end of the asset's current book life (as shown in Exhibit 6.4) regardless of retirement date.

Exhibit 6.4 Book and Tax Life Assumptions on Existing Unit Capital Expenditures

Technology	***Book Life (yr)***	***Tax Life (yr)***
Ongoing Capital Expenditure at Existing Assets		
Lansing	18	20
Ottumwa	15	20
Burlington	7	7
Prairie Creek	13	20
Emery	20	20
Other Generation	25	20

The ongoing capital expenditures, inclusive of environmental costs (water and ash spending), and fixed O&M costs at each of the plants evaluated for early retirement are presented in Exhibit 6.5 through Exhibit 6.9. Following the Phase 1 Analysis, the IPL team performed a refresh of capital budgets; as a result, some adjustments to the projected costs were included in Phase 2 Analysis, as illustrated in the exhibits with dashed lines.

Exhibit 6.5 Lansing Unit 4 Capital Expenditure and Fixed O&M Costs

Lansing Ongoing CapEx + WRASH Spend

Lansing FOM

Exhibit 6.6 Burlington Generating Station Ongoing Capital Expenditure and Fixed O&M Costs[52]

BGS Ongoing CapEx + WRASH Spend

BGS FOM

[52] The Phase 2 Analysis incorporated a proxy (in real 2019$) cost to upgrade the local transmission system, spent during the year of retirement. For example, BGS conversion portfolios incur this cost in 2026, whereas BGS early retirement would incur the cost in 2021. This expenditure is not reflected in the graphics above.

Exhibit 6.7 Prairie Creek Units 1, 3, 4 Ongoing Capital Expenditure and Fixed O&M Costs

Prairie Creek Ongoing CapEx + WRASH Spend

Prairie Creek FOM

Exhibit 6.8 Ottumwa Ongoing Capital Expenditure and Fixed O&M Costs

Ottumwa Ongoing CapEx + WRASH Spend

Ottumwa FOM

Exhibit 6.9 Emery Generating Station Ongoing Capital Expenditure and Fixed O&M Costs

Emery Ongoing CapEx + WRASH Spend

Emery FOM

6.2.3. Financial Treatment of New Assets

The investment costs for newly acquired replacement resources account for: i) installed capital costs; ii) transmission upgrade costs associated with each technology type; and iii) the financing structure for new assets. All ongoing capital expenditures and fixed operating and maintenance costs are accounted in the financial module. The book and tax life assumptions for all replacement options are provided in Exhibit 6.10.

For modeling purposes, IPL and CRA assumed that all owned renewable assets – wind, solar PV, and paired solar and storage resources – would be developed under a tax equity financing structure. The financial module includes such tax benefits for wind with the production tax credit ("PTC") and for solar and paired solar and storage with the investment tax credit ("ITC"), according to the schedule in Exhibit 6.11. With recent federal tax law extending PTC eligibility through 2024, the modeling assumption is that new wind in-service by 2024 will qualify for 60% of the PTC.

Since all new renewable additions are assumed to be tax-equity financed, the analysis incorporates a reduction in upfront capital costs that would be required by IPL, effectively a discount offered by the tax equity partner in exchange for its ability to monetize the tax credits and accelerated depreciation benefits. This general approach is consistent with tax equity partnerships pursued by other investor owned utilities in recent years. The reductions in capital cost for each eligible technology type by online year have been calculated by CRA and summarized in Exhibit 6.12.

Exhibit 6.10 Book and Tax Life Assumptions on Capital Expenditure

Technology	***Book Life (yr)***	***Tax Life (yr)***
Replacement Resource Options		
Wind	30	5
Solar	30	5
Battery Storage	30	7
Paired Solar and Storage	30	5
Gas Peaker	30	15
Gas Combined-Cycle	30	20
Distributed Solar	30	5
Distributed Storage	30	7
Distributed Solar and Storage	30	5
Transmission Upgrade CapEx	40	20

Exhibit 6.11 ITC and PTC Schedules

ITC Phase Down Schedule		
Commence Constr. Year	***In-Service Year***	***ITC Percentage***
2019	2019-2023	30%
2020	2020-2023	26%
2021	2021-2023	22%
2022 or later	2022+	10%

PTC Phase Out Schedule	
In-Service Year[53]	***PTC Percentage***
2020-21	100%
2021-22	80%
2022	60%
2023	60%
2024	60%

[53] Note that PTC eligibility was extended for safe-harbored projects, such that 100%-eligible projects that commenced construction in 2016 can enter into service in 2021 and 80%-eligible projects that commenced construction in 2017 can enter into service in 2022.

Exhibit 6.12 Capital Cost Reduction (Tax Equity) Assumptions for Renewable Replacements

Technology	***Online Year***	***Capital Cost Reduction (Tax Equity)***
Wind	2022	45%
Wind	2023	45%
Wind	2024	45%
Solar	2022	35%
Solar	2023	35%
Solar	2024+	13%[54]
Paired Solar and Storage	2022	35%
Paired Solar and Storage	2023	35%
Paired Solar and Storage	2024+	13%

6.3. Phase 1 Portfolio Results

6.3.1. Dispatch and Generation Mix

The Aurora modeling produced hourly dispatch projections, which included portfolio generation, demand, emissions, and variable costs associated with the portfolio. Exhibit 6.13 presents examples of the annual projected generation mix by fuel type, IPL net demand (after taking into account customer-owned DER), and the IPL net demand after EE energy savings. The net annual market energy purchases for the portfolio are depicted in the graphic with the dashed line at the bottom.[55]

54 The assumption of a tax equity partnership on new owned solar and paired solar plus storage projects installed after 2023 was deployed for modeling purposes, although IPL's ultimate strategy on tax credit realization with a 10% ITC will be determined later based on many factors.

55 Although not presented in graphical form below, the New Regulation optimized "b" portfolios present a similar pattern with regards to net energy position.

Exhibit 6.13 Generation by Fuel Type under Continuing Industry Change, Phase 1 Portfolios

6.3.2. Cost and Financial Results

CRA produced annual revenue requirement projections for the nine operational pathway concepts, for both the “a” and “b” categories, across IPL and stakeholder planning scenarios. Exhibit 6.14 presents an example of the annual revenue requirements developed for portfolios 1a-9a under the Continuing Industry Change scenario. The net present value of revenue requirement (“NPVRR”) results for two timeframes – 2020-2029 (“short-term”) and 2020-2055 (“long-term”) – are summarized in Section 11.7 of the Appendix.

The NPVRR metric is used to summarize total costs for customers across the relevant time period with a single number. These NPVRR summaries present cost projections from a customer perspective and currently include the best assumptions available at the time of the analysis. The remainder of this chapter's discussion will focus on the portfolios optimized under the Continuing Industry Change scenario; however, all NPVRR projections for both sets of portfolios are provided in the Appendix.

Exhibit 6.14 Annual Revenue Requirement Results (2020-2055) under Continuing Industry Change

Lansing Retirement Options

Across all nine scenarios, the early retirement of Lansing 4 provided costs savings in long-term NPVRR, as depicted in Exhibit 6.15. The long-term NPVRR was between $54 and $154 million lower for early Lansing retirement across the five IPL scenarios and between $35 and $241 million lower across the stakeholder scenarios.

Exhibit 6.15 Phase 1 2020-2055 NPVRR Portfolio Deltas: Lansing 2037 vs. 2021

Portfolio 2a *minus* Portfolio 1a (2020-2055 NPVRR)

[redacted]

Portfolio 2a *minus* Portfolio 1a (2020-2055 NPVRR)

[redacted]

Burlington Generating Station Options

Under the initially modeled gas supply costs, gas conversion at Burlington Generating Station to 85 MW in 2021 was approximately [redacted] retirement of the coal unit and gas CTs at Burlington in 2021. However, early retirement in 2021 would expose the portfolio to a high degree of capacity purchase reliance, as depicted in Exhibit 5.12.

Burlington gas conversion at larger sizes – 110 MW (portfolio 3) and 200 MW (portfolio 4) – resulted in around [redacted] long-term NPVRR, respectively, than the 85 MW conversion. This result stems almost entirely from capital costs assumed for installing firm gas infrastructure required for the larger conversion sizes. Because the options at BGS are a near-term decision, and because the gas conversion and CTs are primarily capacity resources, the NPVRR results do not change significantly across the planning scenarios, as depicted in Exhibit 6.16.

Exhibit 6.16 Phase 1 2020-2055 NPVRR Deltas: BGS Conversion and Retirement Options

Portfolio Delta Relative to Portfolio 2a
(2020-2055 NPVRR)

[redacted]

Prairie Creek Options

Early retirement of Prairie Creek 3 and 4 [redacted] the long-term NPVRR by around [redacted] across the core IPL scenarios, as depicted in Exhibit 6.17. [redacted] stakeholder scenarios, early retirement results in [redacted] These findings suggest that the Prairie Creek units provide low-cost capacity to the portfolio, in comparison with other market alternatives.

Exhibit 6.17 Phase 1 2020-2055 NPVRR Deltas: Prairie Creek 3 and 4 Options

[redacted]

Ottumwa Retirement Options

Across the core IPL scenarios, early retirement of Ottumwa in 2026 [redacted] long-term NPVRR by [redacted], while early retirement in 2030 [redacted] NPVRR by [redacted] Retaining Ottumwa through end-of-life presented NPVRR [redacted] compared to other thermal generation resources in the portfolio.

Exhibit 6.18 Phase 1 2020-2055 NPVRR Delta: Ottumwa Retirement Options

Emery Generating Station Options

The retirement of Emery Generating Station before the end of its depreciable life was found to [redacted] long term NPVRR by between [redacted] However, scenarios with [redacted]

Exhibit 6.19 Phase 1 2020-2055 NPVRR Delta: Emery Generating Station Retirement

[redacted]

The following summarizes certain key findings regarding planning scenarios:

- Results regarding Burlington decisions were stable across planning scenarios, as the portfolio differences between portfolios 2 through 5 only exist between 2021 and 2025.
- In general, early retirement of the studied resources provides the most cost savings in the scenario that assumes a carbon pricing regime (New Regulation and IEC-1). Under IEC-1, which assumes the highest carbon price, early retirement at Prairie Creek, Ottumwa, and Emery Generation Station appears lower cost, in contrast to other scenario findings.
- In the Electrification & Economy-Wide Carbon Limit scenario, with highest natural gas prices and high load, early retirement of the studied resources provides less cost savings than the CIC scenario, as coal plants like Lansing and Ottumwa are projected to be more competitive in the market when gas prices are higher.
- The portfolios optimized under the New Regulation scenario with lower transmission costs generally include more renewable additions. When evaluated in the LEG scenario, with high transmission interconnect costs and additional point-to-point transmission charges, the "b" portfolios are higher than the "a" portfolios.

6.3.3. Sustainability Metrics

One of IPL's planning objectives is sustainability, and the Energy Blueprint analysis tracks portfolio carbon emissions and water use as two metrics within this category. As described during Chapter 9, sustainability metrics have been chosen to describe changes with regard to a 2005 baseline.

The CO_2 emissions accounting found the following:

- Across all of IPL's planning scenarios, early retirement at Lansing Unit 4 would achieve a 55% reduction in CO_2 emissions by 2030 from a 2005 baseline, compared to a reduction of just under 50% in the portfolio that retains Lansing until 2037.
- Retiring all Alliant-operated coal by 2030 or 2026 would achieve 67% or 73% reductions, respectively.
- The portfolio that retires all coal and Emery Generating Station by 2030 would achieve a 77% reduction in CO_2 emissions.
- Early retirement of Prairie Creek Units 3 (after the gas conversion) and 4 do not provide substantial emissions reductions, as these gas units are expected to perform similarly to gas peaker units with low capacity factors.

Water usage is expected to change in the following ways:

- Across IPL's planning scenarios, early retirement at Lansing Unit 4 would achieve an 80% water use reduction by 2030 from a 2005 baseline, compared to 61% reduction in the portfolio that retains Lansing until 2037.
- Marginal improvements (within 1 percentage point difference) would be achieved by retiring all coal and/or the Emery Generating Station by 2030. This finding stems from the fact that Ottumwa and Emery use closed-cycle water cooling loops, as compared to the once-through cooling system at Lansing.

These results highlight that early retirement of Lansing Unit 4 alone would allow Alliant to significantly advance its CO_2 emissions and water usage reduction goals.

7. Phase 2 Portfolio Analysis

7.1. Phase 1 Analysis Implications

Based on the Phase 1 analysis conclusions and ongoing stakeholder feedback, several portfolio concepts were deemed relevant for continued testing and refinement in Phase 2. The following key conclusions influenced Phase 2 portfolio development:

- The baseline portfolio with all units running to current end-of-life assumptions was retained as a comparison to alternative portfolio concepts;
- Early retirement of Lansing was retained as a portfolio concept likely to result in lower NPVRR,
- Given comparable costs for Burlington gas conversion without significant gas infrastructure upgrade expenses and early retirement in 2021, further refinement of similar portfolio themes was considered;
- Although Prairie Creek Units 3 and 4 were found to be a low-cost capacity resource, early retirement portfolio themes were advanced to Phase 2, especially given joint feedback from IEC, ELPC, and SC after the May 18, 2020 stakeholder meeting;
- Given the sensitivity of the portfolio cost implications of solar additions to transmission cost assumptions, further evaluation of solar additions by 2023 (based on the results of the New Regulation optimization) was considered;
- Although early retirement of Ottumwa generally resulted in higher NPVRR, joint feedback from IEC, ELPC, and SC after the May 18, 2020 stakeholder meeting suggested that early retirement in 2030 should continue to be evaluated;

7.2. Developments Relevant to Phase 2 Portfolio Construction

After the conclusion of the Phase 1 analysis, IPL identified several relevant developments and reflected on stakeholder feedback as described above, which contributed to the construction of refined portfolios for further evaluation in Phase 2 modeling. These developments are described below.

7.2.1. Lansing End-of-life Extension to 2022

U.S. Environmental Protection Agency ("EPA") rule changes associated with the Effluent Limitation Guidelines ("ELG") rule would potentially allow Lansing to operate with current ash systems until the pond is closed. This option would require the Iowa Department of Natural Resources ("DNR") to approve an amendment to the National Pollution Discharge Elimination System ("NPDES") permit for Lansing, to remove the current deadline for installation of dry bottom ash handling, but it would enable a delay in the retirement date until December 2022. Potential life extension would require a roughly capital investment for minor modifications to redirect water to a new outfall and improve filtering in the fly ash hydroveyor.

7.2.2. Burlington Gas Conversion Potential

IPL conducted tests on Burlington to assess the plant's ability to run on gas during the summer months. Although without firm gas capacity, the plant was able to operate at capacities up to approximately 150 MW.[56] [redacted] However, given the success of the tests, a revised portfolio with higher Burlington summer capacity and minimal firm gas upgrades was evaluated.

7.2.3. Near-term Solar Opportunities

Based on the Phase 1 analysis findings that suggested that solar additions at certain prices could achieve cost savings, IPL's development group assessed the market for the likely all-in costs of solar projects throughout MISO Zone 3 that could enter into service by the end of 2023 and take advantage of the full 30% ITC. This assessment suggested that up to 400 MW of solar may be available through end of 2023 with all-in (solar capital plus transmission network upgrade) costs in the [redacted] range. A comparison of these costs versus the various scenario trajectories is shown in Exhibit 7.1. Based on this finding, IPL evaluated portfolios with these specific cost assumptions in the Phase 2 analysis.

Exhibit 7.1 All-In Solar Cost Comparison (Prior to ITC Impact) vs. Scenario Range

[redacted]

7.3. Phase 2 Portfolio Development

Based on the findings from the Phase 1 analysis and the additional information acquired by IPL, nine Phase 2 portfolios were developed for evaluation. These are summarized in Exhibit 7.2. Following the September 10 stakeholder meeting, an additional portfolio "5a" that combined a Burlington 2021 retirement with solar additions in 2023 was jointly recommended by IEC, ELPC, and SC and included in IPL's analysis. The cumulative nameplate installations of new capacity for each portfolio are presented in Exhibit 7.3, while a more

[56] The modeling assumes that MISO capacity accreditation for the Burlington gas conversion would not be affected by lack of firm winter gas capacity, although IPL recognizes that market rules changes (i.e. a future seasonal resource adequacy construct) may affect the seasonal capacity position.

extensive summary of cumulative installed capacity by resource type can be found in Section 11.8 in the Appendix.

The near-term capacity purchase requirements for each Phase 2 portfolio are illustrated in Exhibit 7.4.

Exhibit 7.2 IPL Phase 2 Existing Resource Operational Pathway Portfolios

Portfolio Concept	Baseline (1)	Lansing (2)	Lansing (2a)	Burlington (3)	Burlington (5)	Burlington (3b)	Prairie Creek (6)	Ottumwa (8)
Portfolio Changes:	None	Lansing (2021) Burlington *(Conversion Option 1)*	Lansing (2022) Burlington *(Conversion Option 1)*	Lansing (2022) Burlington *(Conversion Option 2)*	Lansing (2022) Burlington *(Retire 2021)*	Lansing (2022) Burlington *(Conversion Option 2)* With Solar	Lansing (2022) Burlington *(Conversion Option 2)* Prairie Creek (2025) With Solar	Lansing (2022) Burlington *(Conversion Option 2)* Prairie Creek (2025) Ottumwa (2030) With Solar
Lansing 4	Retire 2037	Early Ret. (2021)	Early Ret. (2022)					
Burlington 1	Gas Conversion in 2021 (85 MW), Retire in 2026	Convert to 85 MW Gas	Convert to 85 MW Gas	Convert to 155 MW Gas	Early Ret. (2021)	Convert to 155 MW Gas		
Prairie Creek 3&4	Gas Conversion in 2025 (unit 3), Retire in 2035						Early Ret. (2025)	
Ottumwa 1	Retire in 2034							Early Ret. (2030)

Evaluate 2023 solar

Exhibit 7.3 Cumulative Nameplate Installations by Phase 2 Portfolio

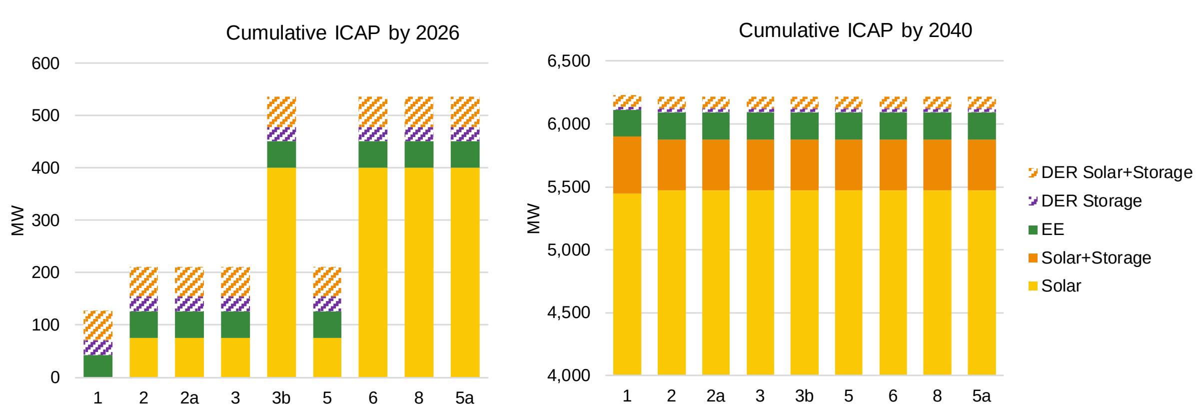


Exhibit 7.4

MISO Capacity Purchases

8. Phase 2 Portfolio Results

All Phase 2 portfolios were evaluated across all market scenarios in the same fashion described in Chapter 6. The remainder of this chapter provides an overview of the key outcomes and results.

8.1. Dispatch and Generation Mix

The Aurora modeling produced hourly dispatch projections, which included portfolio generation, demand, emissions, and variable costs associated with the portfolio. Exhibit 8.1 presents a selection of examples for the annual projected generation mix by fuel type, IPL net demand, and the net annual market energy purchases. These examples particularly highlight the varying levels of coal and solar generation in the portfolios over time.

Exhibit 8.1 Generation by Fuel Type under Continuing Industry Change, Phase 2 Portfolios

8.2. Cost and Financial Results

CRA produced annual revenue requirements across the IPL and stakeholder scenarios for the nine Phase 2 portfolios. The NPVRR results for two timeframes – 2020-2029 ("short-term") and 2020-2055 ("long-term") – are summarized in Section 11.9 of the Appendix. The remainder of this section demonstrates the relative performance of portfolios that evaluate specific retirement decisions and new resource options through the lens of the long-term NPVRR metric.

Lansing Retirement Options

The Phase 2 analysis evaluated retirement at Lansing in 2021 and 2022, as described in Section 7.2.1. Relative to the baseline retirement date of 2037, early retirement is projected to result in cost savings across all IPL and stakeholder scenarios. With retirement in 2021 or 2022, the long-term NPVRR is projected to be approximately \$70 to \$180 million lower than the NPVRR of the portfolio that retains Lansing across IPL scenarios and approximately \$35 to \$270 million lower across stakeholder scenarios. This is shown in Exhibit 8.2.

The 2021 and 2022 retirement dates have similar costs, with the 2022 retirement resulting in a lower NPVRR of approximately $2 to $3 million. This is because the higher fixed O&M and capital costs associated with life extension by one year are largely offset by avoided market capacity purchases in planning year 2021 and additional energy margins associated with continued operation.

Exhibit 8.2 Phase 2 2020-2055 NPVRR Portfolio Deltas: Lansing 2037 vs. 2021 and 2022

[redacted]

[redacted]

Burlington Generating Station Options

In addition to evaluating the Burlington gas conversion at 85 MW and a 2021 retirement, the Phase 2 analysis also evaluated gas conversion at 155 MW with updated capital and fixed O&M cost projections. The financial modeling projects that a larger conversion size of 155 MW would lower NPVRR by approximately [redacted] versus the 85 MW conversion. Similarly, early retirement in 2021 is projected to result in a [redacted] NPVRR versus the 85 MW conversion by approximately [redacted] Given the modeled conversion costs at BGS, the financial trade-off between the larger conversion size and early retirement is [redacted][57]

Exhibit 8.3 Phase 2 2020-2055 NPVRR Portfolio Deltas: BGS Conversion and Retirement Options

[redacted]

Near-term Solar Opportunities

The impact of 2023 solar additions was evaluated with a cost of [redacted] on an all-in basis (solar capital costs plus interconnection costs). In three of the five IPL scenarios, early solar is expected to [redacted]. However, in the New Regulation and Advanced Customer Technology scenarios, which assume a lower solar

[57] As noted earlier, the Phase 2 analysis incorporated an estimated [redacted] (in real 2019$) cost to upgrade the local transmission system at the time of retirement. Conversion portfolios incur this cost in 2026, whereas BGS early retirement would incur the cost in 2021.

capital cost trajectory over time (depicted in Exhibit 7.1), delaying solar additions until after 2023 would result in lower NPVRR. This pattern is reflected in the stakeholder scenarios as well. The IEC-1 and IEC-2 scenarios assume significant declines in solar capacity over time, meaning that acquisition at [redacted] in 2023 results in higher NPVRR than waiting until after 2025. In the LEG scenario, all-in solar costs at the expected [redacted] cost and at a cost that includes higher transmission interconnection charges were both modeled; depending on the cost in 2023, early solar could result in either a higher or lower NPVRR under LEG's scenario assumptions. These comparisons are all summarized in Exhibit 8.4.

Exhibit 8.4 Phase 2 2020-2055 NPVRR Portfolio Deltas: Near-term Solar Opportunities

[redacted]

[redacted]

Prairie Creek Options

With updated fixed O&M cost projections at Prairie Creek, the Phase 2 analysis evaluated the gas conversion of Prairie Creek Unit 3 versus the early retirement of Prairie Creek Units 3 and 4 in 2025. For four out of the five IPL scenarios, early retirement is expected to result in [redacted] long-term NPVRR by [redacted] however, early retirement [redacted] costs in the scenario that assumes a carbon price – New Regulation. Across [redacted] of the nine IPL and stakeholder scenarios, the analysis indicates that retaining the Prairie Creek units results in a [redacted] NPVRR, highlighting Prairie Creek's [redacted] capacity resource for the portfolio. This is shown in Exhibit 8.5.

Exhibit 8.5 Phase 2 2020-2055 NPVRR Portfolio Deltas: Prairie Creek 3 and 4 Options

[redacted]

[redacted]

Ottumwa Retirement Options

In line with the Phase 1 analysis, early retirement at Ottumwa in 2030 is projected to the long-term NPVRR across all five IPL scenarios by approximately . The difference in cost is dependent on the expected price of natural gas, future carbon regulation, and the evolution of the MISO market. In of the four stakeholder scenarios, early retirement results in long-term NPVRR, – IEC-1, with a high carbon price – early retirement results in a NPVRR by These results are summarized in Exhibit 8.6.

Exhibit 8.6 Phase 2 2020-2055 NPVRR Portfolio Deltas: Ottumwa Retirement Options

8.3. Sustainability Metrics

The sustainability impacts of the Phase 2 portfolios are consistent with the Phase 1 analysis. The following provides a brief summary of these findings:

- Across all of IPL's planning scenarios, early retirement at Lansing Unit 4 would achieve a 55% reduction in CO_2 emissions by 2030 from a 2005 baseline, compared to a 49% reduction in the portfolio that retains Lansing until 2037.
- Across IPL's planning scenarios, early retirement at Lansing Unit 4 would achieve an 80% water use reduction by 2030 from a 2005 baseline, compared to 61% reduction in the portfolio that retains Lansing until 2037.
- Early retirement at Burlington Generating Station and/or Prairie Creek Units 3 and 4 are not expected to result in significant emissions reductions, as these gas units are expected to perform with low capacity factors.
- Retiring Ottumwa in 2030 would achieve 67% emissions reductions by 2030, relative to a 2005 baseline, and result in minimal water consumption reductions due to the closed-cycle cooling system at the plant.
- Across the nine portfolios, IPL would add between 122 MW and 1,447 MW of renewable and storage capacity by 2030. Portfolios with earlier coal retirements and 2023 solar additions have higher levels of renewable additions.

9. Dashboard

9.1. Overview and Development

In resource planning, a dashboard can be an effective tool in decision-making. A “dashboard” for resource planning purposes refers to a device that illustrates the performance of different resource alternatives across a set of company-defined performance objectives, indicators, and metrics. A dashboard enables a utility to develop and justify decisions based on those criteria and metrics that matter most to the utility and the customers it serves. This methodology provides a simple, structured means of explaining how sometimes conflicting objectives are traded off to arrive at the preferred resource planning decision.

As part of the Energy Blueprint initiative, the IPL team, with support from CRA, developed a dashboard summary of key objectives and metrics, which was shared in preliminary form with stakeholders at the February 25, 2020 stakeholder meeting. The IPL team emphasized ensuring consistency with corporate objectives, particularly related to customer- and sustainability-oriented goals. Exhibit 9.1 summarizes the dashboard criteria and metrics identified by IPL.

Exhibit 9.1 Energy Blueprint Dashboard Summary

Criteria	Description
Customer Affordability	Minimizing costs to IPL customers • **Metric:** $/MWh generation cost (10-year % CAGR) • **Metric:** Present value of revenue requirement (10-year and total)
Customer Rate Stability	Evaluating sensitivity of resource plans to changes in market conditions • **Metric:** Rate certainty (High to low scenario range total NPVRR) • **Metric:** Rate risk (95^{th} percentile $ of 35-year NPVRR) • **Metric:** Scenario resilience (Highest $/MWh scenario of 21-year NPVRR)
Maintaining Flexibility	Balancing cost minimization with near- and long-term flexibility • **Metric:** Resource optionality (Avg. length of 2020-2040 commitments) • **Metric:** Operational flexibility (2025 dispatchable capacity installed)
Maintaining Reliability	Preserving a reliable portfolio in the context of changing market dynamics • **Metric:** Resource diversity (% of generation mix served by technology type) • **Metric:** Market reliance (Avg. capacity purchases between 2021-2025)
Sustainability	Reaching environmental goals • **Metric:** Clean energy (Cumulative installed new renewables/storage in 2030) • **Metric:** Carbon emissions (Reduction % Alliant CO_2 emissions 2030 vs. 2005) • **Metric:** Water use (Reduction % IPL water withdrawn 2030 vs. 2005)

9.2. Elements and Metrics

The dashboard comprises five overall performance objectives and twelve performance indicators. Each of these is described in more detail below.

9.2.1. Objective 1: Customer Affordability

Customer affordability is one of Alliant Energy's stated corporate goals. For IPL, minimizing cost to customers was a clear objective for the dashboard.

Performance Indicator: Rate Impact

Generation rate impact was selected as a performance indicator of cost minimization. Generation rate impact is measured using a 10-year Compound Annual Growth Rate ("CAGR"), which is a simple expression of the short-term expected impact on customer rates.[58]

Performance Indicator: Present Value Revenue Requirement

Net Present Value Revenue Requirement was selected as a second performance indicator of cost minimization. NPVRR is a representation of the annual costs paid by IPL's customers related to power supply. This includes plant operating and maintenance costs, fuel costs, environmental costs, net purchases and sales of energy and capacity, property and income taxes, and the return on and of capital related to power supply. NPVRR is measured for both 10-year (2020-2029) and 36-year (2020-2055) periods to capture short- and long-term trends.

9.2.2. Objective 2: Customer Rate Stability

IPL understands that market fluctuations in electric and fuel commodities can adversely impact customer rates under a resource plan deemed to be most affordable. The Customer Rate Stability objective is included on the dashboard so that IPL can evaluate the sensitivity of resource plans to changes in market conditions, in addition to seeing their expected costs. The team saw importance of balancing the objective of customer affordability with limiting risk, as the two may sometimes be at odds with one another.

Performance Indicator: Rate Certainty and Rate Risk

The retail rate certainty metric assesses the range of total NPVRR costs between the highest and lowest scenario outcomes. Rate risk was selected as a performance indicator to evaluate risk across a stochastic distribution of potential portfolio cost options. After the completion of Phase 1 and after consultation with stakeholders during and after the May 18, 2020 stakeholder meeting, IPL decided to not perform stochastic analysis, meaning that this metric is not reported in the dashboard below.

Performance Indicator: Scenario Resilience

Scenario resilience was selected as a performance indicator for limiting cost risk. Scenario resilience is defined as the highest expected cost of each portfolio option under its worst performing resource planning scenario in the deterministic modeling environment. Scenario resilience ($/MWh) is measured as the maximum 21-year NPVRR (2020-2040) under any scenario, divided by the net present value of load over that scenario.

[58] Note that in the calculation of the 10-year CAGR, IPL calculated a starting 2021 generation rate as the average across all portfolios to avoid advantaging or disadvantaging portfolios with different cost profiles in the starting, "baseline" year.

9.2.3. Objective 3: Maintaining Flexibility

The team identified “maintaining flexibility” as an important objective to be included on the dashboard. In light of consistently and sometimes rapidly changing conditions in the industry that impact power supply, the team saw the importance of balancing the objective of cost minimization with an ability to maintain flexibility.

Performance Indicator: Resource Optionality

Resource optionality was selected as a performance indicator for maintaining flexibility. Resource optionality is defined as the level to which IPL is locked into long-term commitments as part of a portfolio option. In general, new resources represent a longer commitment, while existing owned resources or contracted resources can often represent a shorter commitment. Resource optionality is measured as the average unforced capacity-weighted duration of commitments over the period 2020 to 2040.

Performance Indicator: Operational Flexibility

Operational flexibility was selected as a second performance indicator for maintaining flexibility. Operational flexibility is defined as the ability of the IPL portfolio to have sufficient dispatchable capacity available when needed in response to shifts in net load requirements over time. The increase in intermittent renewable resources across MISO may create the need, under some scenarios, for flexible resources that can provide a reliability service and balance the system. Understanding each portfolio’s ability to provide dispatchable capacity to the system is an important factor for determining the preferred plan and is a simple proxy for future ancillary services and seasonal capacity value, which is highly uncertain. Operational flexibility is measured as the amount of dispatchable, non-intermittent capacity included in the portfolio in 2025, whether owned or contracted.

9.2.4. Objective 4: Maintaining Reliability

The team identified maintaining reliability as an important, fundamental objective to be included on the dashboard. Reliability is an essential aspect of a utility’s mission. All portfolio options evaluated in the Clean Energy Blueprint process are assumed to fully satisfy MISO resource adequacy requirements, so for purposes of the dashboard, reliability was also viewed from the perspective of resource diversity and secured capacity.

Performance Indicator: Diversity of Resource Mix

Diversity of resource mix was selected as a performance indicator for maintaining reliability. Diversity of resource mix is defined as the proportion of IPL load that is met by each type of generation technology and fuel. While the financial impacts of resource diversity are implicitly captured within the previously identified metrics, it is still valuable to understand the portion of IPL load that is being served by different resource types because no quantitative modeling exercise will be able to capture all possible cost outcomes for key uncertainty variables. For example, fuel price changes, environmental policy, weather trends, and potential MISO market reforms may impact different resource types differently. Diversity of resource mix is measured as the percent of 2030 load served by each technology and fuel.

Performance Indicator: Market Reliance

Although the MISO market is ultimately responsible for managing the regional reserve margin requirements in the system, capacity market reliance was selected as a performance indicator for maintaining reliability to reflect the fact that exposure to a short capacity position could result in the portfolio facing higher costs than expected in the event that reserve margins in MISO market tighten. Market reliance is defined as the expected average capacity market purchases in MW across the 2021 through 2025 time period.

9.2.5. Objective 5: Sustainability

The team identified sustainability as an important objective to be included on the dashboard, consistent with IPL's environmental targets.

Performance Indicator: Clean Energy

Clean energy was selected as a performance indicator for sustainability. In this setting, clean energy is defined as energy generated from renewable technologies, and for purposes of the dashboard, incremental clean energy additions were recorded for each portfolio. These were measured with the cumulative new installed capacity of renewables and storage added to each portfolio by 2030.

Performance Indicator: Carbon Emissions

Carbon emissions were selected as a performance indicator for sustainability. IPL carbon emissions are defined as the greenhouse gas emissions from its owned and contracted generating resources. Alliant announced its goal to cut carbon emissions 40% by 2030 and 80% by 2050, compared to the 2005 emissions level and eliminate all existing coal from its generation mix by 2050. Reporting the emissions results of portfolio alternatives is critical to understanding how each resource plan compares with the stated environmental goals. The carbon emission indicator is measured as the percent reduction in total IPL emissions in 2030 versus 2005 emissions.

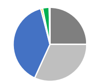
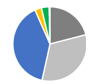
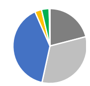
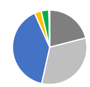
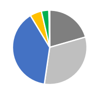
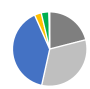
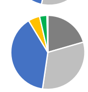
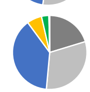
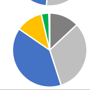
Performance Indicator: Water Use

Water use was selected as a performance indicator for sustainability. IPL water use is defined as the total amount of water withdrawn at IPL's owned and contracted generating resources. Alliant announced its goal to cut water supply needs from fossil-fueled generation 75% by 2030. Reporting the water use results of portfolio alternatives is necessary for understanding how each resource plan compares with the stated environmental goals. Water use is measured as the percent reduction in IPL water consumption across owned and contracted resources in 2030 versus 2005 water consumption.

9.3. Overall Dashboard Results

The complete dashboard results are provided in Exhibit 9.2, where lighter shading indicates better performance within each metric relative to the other portfolio options.

Exhibit 9.2 Overall Dashboard Results

	Customer Affordability			Customer Rate Stability		Maintaining Flexibility		Maintaining Reliability		Sustainability		
	$/MWh Gen Cost	Present Value Revenue Requirement		Rate Certainty	Scenario Resilience	Resource Optionality	Operational Flexibility	Resource Diversity	Market Reliance	Clean Energy	Carbon Emissions	Water Use
	10-Yr CAGR - IPL Scenario Avg.	10-Yr NPVRR - IPL Scenario Avg.	Total NPVRR IPL Scenario Avg.	High - Low Scenario Range NPVRR	Highest Scenario Levelized Gen Cost	Average Duration of Commitments	Dispatchable Capacity Installed	IPL Generation Mix (MWh) by Technology	Avg. Capacity Purchases	Cumulative New Installed Renewables / Storage	Reduction in IPL Emissions	Reduction in IPL Water Withdrawal
	2021-2030	2020-2029	2020-2055	2020-2055	2020-2040	2020-2040	2025	2030	2021-2025	2030	2030 vs. 2005	2030 vs. 2005
Portfolio	%	$MM	$MM	$MM	$/MWh	Years	MW	% by Tech	MW UCAP	MW ICAP	%	%
Portfolio 1 Baseline	**0.03%**	**$ 5,142**	**$ 10,484**	**$ 1,853**	**$48.37**	**14.03**	**2,944**		**0**	**122**	**49%**	**61%**
Portfolio 2 Lansing 2021, Burlington Conversion 85 MW	**0.00%**	**$ 5,055**	**$ 10,348**	**$ 1,933**	**$48.21**	**14.50**	**2,693**		**150**	**372**	**55%**	**80%**
Portfolio 2a Lansing 2022, Burlington Conversion 85 MW	**0.00%**	**$ 5,051**	**$ 10,346**	**$ 1,932**	**$48.20**	**14.43**	**2,693**		**110**	**372**	**55%**	**80%**
Portfolio 3 Lansing 2022, Burlington Conversion 150 MW	**0.00%**	**$ 5,047**	**$ 10,342**	**$ 1,932**	**$48.18**	**14.35**	**2,763**		**60**	**372**	**55%**	**80%**
Portfolio 3b Lansing 2022, Burlington Conversion 150 MW, Early Solar	**0.00%**	**$ 5,096**	**$ 10,332**	**$ 1,909**	**$48.23**	**14.43**	**2,763**		**40**	**522**	**55%**	**80%**
Portfolio 5 Lansing 2022, Burlington 2021	**0.00%**	**$ 5,049**	**$ 10,343**	**$ 1,933**	**$48.18**	**14.59**	**2,564**		**230**	**372**	**55%**	**80%**
Portfolio 5a Lansing 2022, Burlington 2021, Early Solar	**0.00%**	**$ 5,090**	**$ 10,324**	**$ 1,913**	**$48.20**	**14.66**	**2,564**		**150**	**522**	**55%**	**80%**
Portfolio 6 Prairie Creek 3&4 Retire by 2025	**0.11%**	**$ 5,095**	**$ 10,339**	**$ 1,912**	**$48.33**	**14.60**	**2,763**		**40**	**672**	**55%**	**80%**
Portfolio 8 Alliant Coal Retires 2030	**0.88%**	**$ 5,092**	**$ 10,396**	**$ 1,955**	**$48.97**	**14.81**	**2,763**		**40**	**1,447**	**67%**	**81%**

Coal
Gas
Wind
Solar
DSM
Other

10. Conclusions

Over the course of the resource planning component of IPL's Clean Energy Blueprint process, CRA and IPL performed analysis and evaluated a range of resource planning pathways across multi-dimensional objectives. As a result, an integrated dashboard (in Section 9.3) was developed to illustrate several performance indicators and tradeoffs. The following major observations from the analysis were made about the existing owned and operated IPL fleet:

- Early retirement of Lansing Unit 4 improves near- and long-term affordability and enables IPL to advance its sustainability goals for CO_2 emissions and water usage reductions. This result was supported across all IPL and stakeholder scenarios.
- Under the Consent Decree, the Burlington Generating Station will cease burning coal by the end of 2021. Several near-term resource planning options after 2021 were evaluated for BGS, including gas conversion of Unit 1 at various capacity levels or the retirement of the unit and the gas peakers on site in 2021. Overall, the following conclusions were made:
  - The analysis found that various options at Burlington resulted in similar impacts on the affordability metrics.
  - However, early retirement of BGS in 2021 would result in greater reliance on MISO market capacity purchases to meet resource adequacy requirements for the period 2021 through 2025. In addition, the reliable dispatchable capacity available would correspondingly be reduced by approximately 200 MW.
  - Gas conversion and early retirement options present similar environmental implications, as the gas units are expected to dispatch at low capacity factors.
- Prairie Creek Units 1 is planned to retire in 2025 and, under the Consent Decree, Unit 3 is required to be retired or refueled no later than December 31, 2025. The options to convert Prairie Creek Unit 3 to gas and continue operation of Units 3 and 4 (currently running on gas) through 2035, or to retire Units 1, 3, and 4 in 2025 were evaluated. Under the modeled cost assumptions in the Phase 2 Analysis, gas conversion of Prairie Creek Unit 3 and plant retirement in 2035 results in lower NPVRR in six of the nine IPL and stakeholder scenarios and mitigates exposure to the MISO market for capacity. Nevertheless, in scenarios that assume a price on CO_2 emissions, early retirement presents long-term cost savings.
- Early retirement of Ottumwa was evaluated in Phases 1 and 2 of the Clean Energy Blueprint analysis, and in both stages, retaining Ottumwa through its planned end-of-life results in lower NPVRR across 8 of the 9 IPL and stakeholder scenarios. This result is supported by the relatively attractive dispatch economics of Ottumwa in comparison to other coal units in IPL's portfolio.
- Retaining the Emery Generating Station through its planned end-of-life was found to result in lower NPVRR than retiring the unit early across most scenarios according to the Phase 1 analysis.

The following major observations from the analysis were made about new resource options:

- Consistent with current available information, up to 400 MW of utility-scale solar PV with the potential to enter into service by the end of 2023 and receive a 30% ITC was modeled. Such solar was evaluated in the Phase 2 analysis based on the Phase 1 optimization findings under the New Regulation scenario, with the following conclusions:
    - Solar at an all-in cost of [redacted] in 2023 would provide long-term savings in 3 of the 5 IPL scenarios, namely scenarios that assume "base" capital cost trajectories or high load expectations.
    - However, in the scenarios that assume rapid declines in capital costs over time, the analysis suggests that waiting for more cost-effective solar in the future would result in a lower NPVRR.
    - This observation points to the significance of realized capital cost projections, and as greater information becomes available regarding actual projects in the future, the conclusions outlined herein may shift.
- Targeted distributed energy resources, such as battery storage or paired solar and storage systems, may provide benefits to IPL by deferring planned distribution system upgrades and by providing additional energy and capacity value for the portfolio. The value of DER additions depends on projections of capital costs and the magnitude of cost savings associated with avoided distribution system investments.
- A number of energy efficiency measures may provide energy and capacity value to IPL's portfolio by reducing load and peak demand.

The resource planning Clean Energy Blueprint stakeholder initiative was an extensive, collaborative effort between IPL, CRA, and the Iowa stakeholders who participated in providing feedback and input into the process, including through six meetings convened by IPL. The analysis herein revealed multiple resource planning tradeoffs along utility objectives for customer affordability, customer rate stability, maintaining flexibility, maintaining reliability, and sustainability; and provides a number of viable paths for IPL with regard to resource retirement and new resource additions. While this resource planning process within IPL's Clean Energy Blueprint will guide IPL's near-term resource planning decisions, any future decisions will depend on a number of factors, including the ability to secure market capacity purchases at the rates used in this analysis, the actual costs of replacement resources, and other legal, regulatory, financial and operational considerations.

11. Appendix

11.1. Appendix A: IPL Portfolio Model Calibration Details

CRA conducted a calibration exercise to ensure the Aurora model was reasonably simulating IPL plant performance prior to engaging in the forward-looking Energy Blueprint analysis.

This calibration procedure includes two major elements:

- Calibration of historical performance for the past three years (2017-2019), where Aurora dispatch results are compared to historical benchmarks; and
- Calibration of performance in the near-term future (2020-2024), where Aurora dispatch results are compared to historical performance, in light of expected market changes.

11.1.1. Calibration Benchmarking Data

While operational parameters for IPL's resources remained the same throughout the two calibration testing periods, market price signals used to model dispatch were gathered from historical data as well as market forwards outlooks. The data sources for the calibration modeling procedure are summarized in Exhibit 11.1. Data used for the historical period was gathered from a variety of sources, including ABB's Energy Velocity Suite and SNL (S&P Global Market Intelligence Commodity Charting Tool), and includes energy commodity prices and reported plant generation. Price inputs for the forward period are CRA's projections for the Continuing Industry Change scenario using underlying WoodMac commodity price forecasts.

Aurora's long-term capacity expansion ("LTCE") feature was used to develop hourly LMPs, based on scenario planning assumptions (see Chapter 4 for more detail). To capture additional day-to-day fluctuations in energy prices, CRA introduced daily volatility to the energy price forecast based on the 2017 historic year, while keeping monthly average on-peak and off-peak prices and hourly shapes within a day consistent with the model output.

This preserves both the monthly average prices and the hourly model price shape, but the spread of daily average prices within a single month increases. The introduction of daily volatility generally improves plant dispatch calibration, as it is more reflective of actual market conditions. Exhibit 11.2 summarizes historical and projected natural gas and MISO power prices, while Exhibit 11.3 illustrates the trends in delivered coal prices at each of the IPL owned and co-owned coal plants, based on reported values from Energy Velocity for the historical time period and projections by WoodMac in the H1 2019 No Carbon Case.[59] Over the forward calibration period, natural gas prices, the delivered coal prices for the IPL plants, and MISO power prices are projected to remain relatively flat in real terms.

[59] Note that the reported values for Lansing coal prices in 2017 and 2018 appeared inconsistent with typical trends; based on IPL feedback, CRA applied an adjustment (dashed line in) for calibration purposes.

Exhibit 11.1 Calibration Benchmarking Data for Historical and Forecast Periods

	Historical Period (2017-2019)	***Forecast Period (2020-2024)***
Plant parameters	**IPL**: all plant operational assumptions remained the same between time periods	
Plant Generation	**Energy Velocity, SNL**: generation (MWh) for plants, as reported for EPA Continuous Emissions Monitoring System	**N/A**
Electricity Prices[60]	**Energy Velocity**: hourly day-ahead LMPs for the Alliant West Zone ("ALTW")	**CRA**: hourly electricity price forecasts under the Continuing Industry Change scenario
Natural Gas Prices	**SNL**: spot index prices for the Ventura hub, with gas delivery adders for certain IPL plants based on WoodMac	**WoodMac**: monthly prices for MISO Iowa region under 2019 H1 No Carbon case, with gas delivery adders for certain IPL plants[61]
Coal Prices	**Energy Velocity**: annual delivered coal prices as reported to EIA	**WoodMac**: annual delivered coal prices under 2019 H1 No Carbon case
Nodal Basis Adders	**Energy Velocity**: historical nodal basis at IPL plants, summarized for on/off-peak time periods at monthly resolution	**IPL**: PROMOD nodal analysis results

60 Since 98% of IPL load is met in ALTW, the simplifying assumption is made that IPL portfolio dispatches to ALTW prices, inclusive of the nodal basis adders noted in the table.

61 A blend between SNL forwards for Ventura hub and WoodMac MISO Iowa region for the near-term period 2020-2022 is applied, because of the discrepancy between the historical Ventura hub prices and future projections for WoodMac MISO Iowa region. For the remainder of the modeling time period (2024-2040), WoodMac delivered natural gas projections under the 2019 H1 No Carbon case are applied.

To reflect the actual local market conditions for IPL units, nodal bases to the zonal Alliant West (“ALTW”) electricity prices were incorporated into the Aurora model. For the historical time period, hourly nodal prices at the respective IPL plants were taken from Energy Velocity and represented for on-/off-peak time periods at monthly granularity. For the forwards modeling period, IPL provided CRA the results of its PROMOD simulation, a forecast that provides nodal LMP projections based on expected MISO transmission topology.[62] IPL’s model is based on MISO Transmission Expansion Plan (“MTEP”) future scenarios, reflecting the best available assumptions about future transmission topology and generation. CRA has

62 IPL simulated PROMOD for three model years (2023, 2028, 2033); CRA represents the nodal adjustment as a percentage premium/discount to the ALTW LMP and applies this to the MISO Zone 3 price from Aurora forecast. CRA interpolates between future model years and holds the 2033 percentage premium/discount constant for the remainder of the forward modeling period.

incorporated these nodal price inputs for on-/off-peak periods at monthly granularity for the forwards period. LMPs at Lansing Unit 4 are [redacted] to the IPL zonal LMP during on- and off-peak hours.

11.1.2. Calibration Methodology

The aim of the calibration modeling exercise was to replicate the dispatch of IPL's plants, given specified plant parameters, as closely as possible to historical performance and within reasonable expectations of the near-term future. When assessing model output versus historical actuals or future expectations, the main modeling levers to calibrate plant performance were:

- Aurora dispatch logic: namely, the "non-cycling" parameter represents a premium to the dispatch price for unit commitment;
- Plant heat rates: small adjustments to base and minimum output heat rates can be made and verified against values reported by public sources (such as SNL) to be within reasonable bounds; and
- Minimum capacity for plant dispatch was calibrated to historical hourly generation reported by SNL.

In addition, historical outages, often due to maintenance events, were taken into account in the model. The main benchmarks used to assess plant performance calibration were generation (MWh) and capacity factor. CRA has also compared modeled fuel costs and energy margins with actuals in order to ensure reasonableness of dispatch results. CRA recognizes differences between historical and modeled dispatch may result from certain real-time events not captured here; for example, historical forced outages and capacity ratings may be different from those reported in the latest Planning Year information.

11.1.3. Lansing Calibration Findings

Exhibit 11.4 presents a summary of Lansing Unit 4 capacity factors, as dispatched in Aurora, along with historical dispatch. The backcast model simulation matches the historical seasonal behavior quite closely, and the forecast expects similar trends. The seasonality of Lansing Unit 4 dispatch is also summarized in the seasonal capacity factors graphic in Exhibit 11.5. The plant is expected to operate most when [redacted] Overall, this summary confirms that the Aurora simulation tool is representing the plant's observed behavior in a reasonable fashion, with similar operations expected in the near future.

[redacted]

Exhibit 11.4 Lansing Unit 4 Capacity Factor Results: Calibration

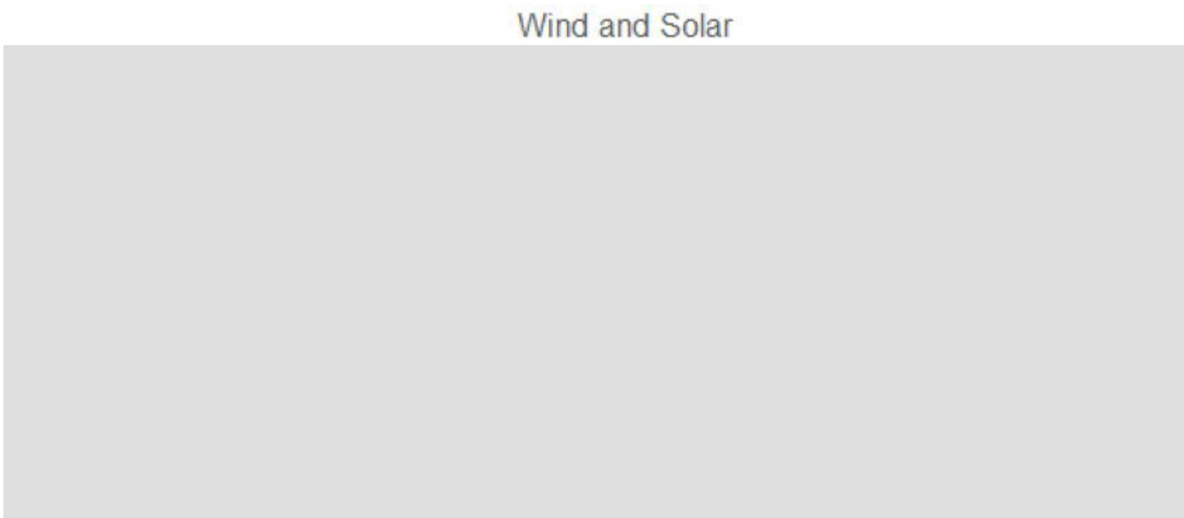
Exhibit 11.5 Lansing Unit 4 Seasonal Capacity Factor (2021-2025) under Continuing Industry Change[64]

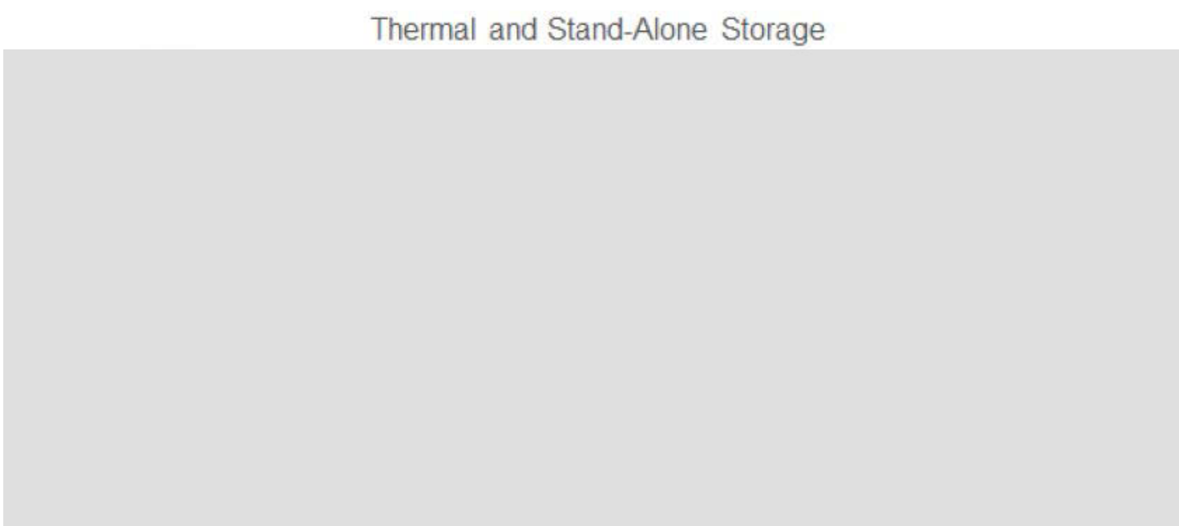
[64] Summer includes June, July, and August. Winter includes December, January, and February. Spring includes March, April, and May. Fall includes September, October, and November.

11.2. Appendix B: Transmission Interconnection Costs for MISO Scenario Analysis

Exhibit 11.6 summarizes the transmission interconnection costs assumed for new resources in the Western MISO zones in the MISO scenario analysis described in Chapter 4. These assumptions are slightly different than those applied to IPL portfolios and referenced in Section 5.2.1. The IPL-specific assumptions included the same scenario themes, but the timing of transmission cost declines and differentiation across technologies was updated based on IPL-specific knowledge and stakeholder input.

Exhibit 11.6 MISO Scenario Analysis Transmission Interconnection Cost Assumptions





11.3. Appendix C: Long-term Capacity Expansion Analysis Detailed Modeling Approach

From a process perspective, the long-term capacity expansion simulation for the MISO market is performed in a limited-hours setting to reduce run time and allow for the model to converge on a solution.[65] After the long-term runs are complete, a resulting capacity expansion and retirement plan is produced. CRA then runs the Aurora model in standard, hourly configuration to produce a full forecast of dispatch and market prices across MISO.

Since the long-term portfolio optimization is focused solely on least cost, CRA made certain assumptions and adjustments to reflect elements of the scenario themes not covered in the least-cost algorithm:

- Units must be flagged as eligible for retirement in the long-term capacity optimization runs. In order to ensure a reasonable range of coal retirement outcomes across scenarios, CRA changed retirement eligibility across scenarios in the following fashion:
    - An annual retirement limit (above previously announced retirements) was set to prevent the model from retiring large amounts of capacity all at once based on a simple economic signal. Limits help reflect a more realistic pace of utility decision making, MISO approval of deactivation requests, and how quickly new resource options can be integrated into the MISO system. Limits are higher in the near term and slowed over time to reflect added difficulty associated with higher quantities of intermittent resources in the MISO system.
    - Based on indicative results in the Continuing Industry Change case, retirements for MISO-wide coal units built after 1980 were restricted to announced retirements. In the Market Stagnation case, retirements were restricted further to allow economic retirements for only plants built before 1973. Other cases allowed economic retirement for all coal units in MISO.
- Under deterministic energy price simulations with limited run hours, certain resource options like storage and peaking capacity, which are likely to realize additional value due to sub-hourly flexibility and their ability to monetize real-time market price spikes and ancillary services markets, will be unlikely to be selected by the model. Furthermore, resource planners are likely to evaluate such resource options with an eye towards other attributes, including the ability to directly firm up intermittent resources with pairing strategies, while regulators and system operators like MISO will potentially be altering rules and requirements to capture such dynamics. Due to these factors, CRA incorporated user-defined resource additions based on the amount of solar capacity built by the long-term model as follows:
    - In the Continuing Industry Change, Market Stagnation, Advanced Customer Technology, and "IEC-2" cases, CRA assumed that storage was added in an amount consistent with 30% of the solar capacity coming online in 2023 supported by storage at a 4:1 ratio.[66] This grew to an 80% ratio for new projects by 2040. As the peak capacity value of these resources increases with storage

[65] This approach is generally recommended by Energy Exemplar, the licenser of Aurora, and is the approach used by CRA in most market work in large systems. CRA has found that the limited hours approach, with properly representative hours across a selection of days and weeks for each month, provides results broadly consistent with all-hours runs.

[66] For modeling purposes in Aurora, this storage was directly paired with solar resources.

pairing, overall solar capacity was reduced to match the original MISO reserve margin from the long-term capacity expansion run.

- In the New Regulation, Electrification and Economy-Wide Carbon Limit, "IEC-1," and OCA cases, CRA assumed that storage would be added at a 4:1 ratio consistent with 30% of solar projects in 2023, and grew this share to 100% by 2040, making a corresponding adjustment to overall solar capacity.
- In several cases, additional market storage[67] and gas peaking capacity was included based on zones with high renewable penetration and significant market price volatility. These additional resources were included based on reserve margin requirements and the relative economics of storage and peaker additions.[68]

[67] For modeling purposes in Aurora, this market storage was evaluated as stand-alone storage able to charge and discharge directly with the MISO market.

[68] For example, in the Continuing Industry Change scenario, gas peaking capacity was lower cost and comprised most additions. In the New Regulation and "IEC-1" scenarios, lower assumed battery costs drove the incremental capacity additions to be more weighted towards storage resources. In the Electrification and Economy-Wide Carbon Limit and OCA scenarios, higher load growth drove more additions overall.

11.4. Appendix D: Customer-Owned Distributed Generation by Scenario

IPL provided CRA with a baseline forecast of expected load for the long-term planning horizon (see Exhibit 3.4) which takes into account baseline assumptions for customer-owned distributed generation ("DG") and the 2019-2023 Energy Efficiency Plan. However, IPL's net demand across planning scenarios takes into account a combination of factors: planning scenario load growth assumptions, customer-owned DG projections, and incremental energy efficiency measures adopted by customers.

The role of customer-owned DG is expected to have a meaningful impact on utility resource planning over the long-term horizon. The IPL and CRA teams worked closely together to define a set of scenarios for customer-owned DG installations in the IPL load zone, following the planning scenarios' narratives of technology capital cost declines, load growth, and market incentives for DG adoption. While Section 4.2.3 describes load adjustments due to DG under the Advanced Customers Technology scenario for the MISO-wide market simulation, customer-owned DG forecasts specific to IPL's portfolio were mapped across the planning scenarios. The scenario mapping and corresponding DG trajectories for the IPL scenarios are provided in Exhibit 11.7 and Exhibit 11.8 [69] The scenario-specific net load (peak and average) projections are provided in Exhibit 11.9.

Exhibit 11.7 Customer-Owned DG Scenarios

	Continuing Industry Change	Advanced Customer Technology	Market Stagnation	New Reg-ulation	Electrifi-cation & Economy-Wide Car-bon Limit
Solar Trajectory:	Base	High	Conservative	High	High
Solar+Storage Trajectory:	Base	High	Conservative	Base	Base

[69] Stakeholder scenarios map to the DG trajectories for the IPL scenarios upon which they are based (see Exhibit 4.4).

Exhibit 11.8 Cumulative Installed Customer-Owned DG Scenarios

Exhibit 11.9 IPL Scenario Net Load (Peak and Average) Trajectories

	Continuing Industry Change		Advanced Customer Technology		Market Stagnation		New Regulation		Electrification & Economy-Wide Carbon Limit	
Year	***Peak***	***Avg***	***Peak***	***Avg***	***Peak***	***Avg***	***Peak***	***Avg***	***Peak***	***Avg***
2020										
2021										
2022										
2023										
2024										
2025										
2026										
2027										
2028										
2029										
2030										
2031										
2032										
2033										
2034										
2035										
2036										
2037										
2038										
2039										
2040										

11.5. Appendix E: IPL Portfolio Optimization Constraints

When performing portfolio optimization for IPL, the Aurora model aims to minimize the NPVRR of portfolio costs subject to user constraints. CRA and IPL have incorporated the following constraints in the modeling:

- Planning reserve margin targets between 8.9% and 20%;
- Net energy sales constrained to 30% of average annual IPL load;[70] and
- Capacity purchases are [redacted] and up to 100 MW for the longer-term planning period (2026-2040).[71]

[70] This limit was identified as a reasonable benchmark based on the range of historical purchases/sales positions for IPL and MidAmerican over the last several years, as per FERC Form 1.

[71] In the near-term, a meaningful level of bilateral capacity purchases are expected to be available based on the current supply-demand balance in the Iowa region and IPL's market intelligence, although this is uncertain and will need to be confirmed prior to IPL finalizing its plans. Over the long term, it is not certain that excess capacity will be available. Given IPL's obligation to serve load, a smaller market purchase limit was deemed appropriate.

11.6. Appendix F: Phase 1 Optimized Portfolios

Exhibit 11.10 Cumulative Installed Capacity by Phase 1 Portfolio

Technology	*In-stalled*	1a	2a	3a	4a	5a	6a	7a	8a	9a
Solar	2023									
	2026									
	2030									
	2035									
	2040									
Wind	2026									
	2030									
	2035									
	2040									
Storage	2026									
	2030									
	2035									
	2040									
Paired Solar and Storage[72]	2026									
	2030									
	2035									
	2040									
Energy Efficiency (Peak Hour Savings MW)	2026									
	2030									
	2035									
	2040									
Distributed Storage (Utility-Owned)	2026									
	2030									
	2035									
	2040									
Distributed Solar and Storage (Utility-Owned)[73]	2026									
	2030									
	2035									
	2040									

[72] Capacity numbers represent total capacity for the paired resource at a 4:1 solar to storage ratio. Thus, 400 MW represents 320 MW of solar and 80 MW of storage.

[73] Capacity numbers represent total capacity for the paired resource at a 2:1 solar to storage ratio.

Technology	***In-stalled***	**1b**	**2b**	**3b**	**4b**	**5b**	**6b**	**7b**	**8b**	**9b**
Solar	**2023**									
	2026									
	2030									
	2035									
	2040									
Wind	**2026**									
	2030									
	2035									
	2040									
Storage	**2026**									
	2030									
	2035									
	2040									
Paired Solar and Stor-age[74]	**2026**									
	2030									
	2035									
	2040									
Energy Efficiency (Peak Hour Savings MW)	**2026**									
	2030									
	2035									
	2040									
Distributed Storage (Utility-Owned)	**2026**									
	2030									
	2035									
	2040									
Distributed Solar and Storage (Utility-Owned)[75]	**2026**									
	2030									
	2035									
	2040									

[74] Capacity numbers represent total capacity for the paired resource at a 4:1 solar to storage ratio. Thus, 600 MW represents 450 MW of solar and 150 MW of storage.

[75] Capacity numbers represent total capacity for the paired resource at a 2:1 solar to storage ratio.

11.7. Appendix G: Phase 1 NPVRR Results

Exhibit 11.11 Phase 1 2020-2029 NPVRR Results Across IPL and Stakeholder Scenarios

NPVRR ($MM)	**1a**	**2a**	**3a**	**4a**	**5a**	**6a**	**7a**	**8a**	**9a**
Continuing Industry Change									
Advanced Customer Technology									
Market Stagnation									
New Regulation									
Electrification& Economy-Wide Carbon Limit									
IEC/ELPC/SC Alternative #1									
IEC/ELPC/SC Alternative #2									
LEG Alternative #1									
OCA Alternative #1									

NPVRR ($MM)	**1b**	**2b**	**3b**	**4b**	**5b**	**6b**	**7b**	**8b**	**9b**
Continuing Industry Change									
Advanced Customer Technology									
Market Stagnation									
New Regulation									
Electrification& Economy-Wide Carbon Limit									
IEC/ELPC/SC Alternative #1									
IEC/ELPC/SC Alternative #2									
LEG Alternative #1									
OCA Alternative #1									

11.8. Appendix H: Phase 2 Optimized Portfolios

Exhibit 11.12 Cumulative Installed Capacity by Phase 2 Portfolio

Technology	*In-stalled*	1	2	2a	3	3b	5	5a	6	8
Solar	2023									
	2026									
	2030									
	2035									
	2040									
Wind	2026									
	2030									
	2035									
	2040									
Storage	2026									
	2030									
	2035									
	2040									
Paired Solar and Storage[76]	2026									
	2030									
	2035									
	2040									
Energy Efficiency (Peak Hour Savings MW)	2026									
	2030									
	2035									
	2040									
Distributed Storage (Utility-Owned)	2026									
	2030									
	2035									
	2040									
Distributed Solar and Storage (Utility-Owned)[77]	2026									
	2030									
	2035									
	2040									

[76] Capacity numbers represent total capacity for the paired resource at a 4:1 solar to storage ratio. Thus, 400 MW represents 320 MW of solar and 80 MW of storage.

[77] Capacity numbers represent total capacity for the paired resource at a 2:1 solar to storage ratio.

11.9. Appendix I: Phase 2 NPVRR Results

Exhibit 11.13 Phase 2 2020-2029 NPVRR Results Across IPL and Stakeholder Scenarios

NPVRR ($MM)	**1**	**2**	**2a**	**3**	**3b**	**5**	**6**	**8**	**5a**
Continuing Industry Change									
Advanced Customer Technology									
Market Stagnation									
New Regulation									
Electrification& Economy-Wide Carbon Limit									
IEC/ELPC/SC Alternative #1									
IEC/ELPC/SC Alternative #2									
LEG Alternative #1									
OCA Alternative #1									

Exhibit 11.14 Phase 2 2020-2055 NPVRR Results Across IPL and Stakeholder Scenarios

NPVRR ($MM)	**1**	**2**	**2a**	**3**	**3b**	**5**	**6**	**8**	**5a**
Continuing Industry Change									
Advanced Customer Technology									
Market Stagnation									
New Regulation									
Electrification& Economy-Wide Carbon Limit									
IEC/ELPC/SC Alternative #1									
IEC/ELPC/SC Alternative #2									
LEG Alternative #1									
OCA Alternative #1									

Exhibit 11.15 Phase 1 2020-2055 NPVRR Results Across IPL and Stakeholder Scenarios

NPVRR ($MM)	**1a**	**2a**	**3a**	**4a**	**5a**	**6a**	**7a**	**8a**	**9a**
Continuing Industry Change									
Advanced Customer Technology									
Market Stagnation									
New Regulation									
Electrification& Economy-Wide Carbon Limit									
IEC/ELPC/SC Alternative #1									
IEC/ELPC/SC Alternative #2									
LEG Alternative #1									
OCA Alternative #1									

NPVRR ($MM)	**1b**	**2b**	**3b**	**4b**	**5b**	**6b**	**7b**	**8b**	**9b**
Continuing Industry Change									
Advanced Customer Technology									
Market Stagnation									
New Regulation									
Electrification& Economy-Wide Carbon Limit									
IEC/ELPC/SC Alternative #1									
IEC/ELPC/SC Alternative #2									
LEG Alternative #1									
OCA Alternative #1									

11.10. Appendix J: CRA Firm and Team Overview

Charles River Associates (CRA) is a consulting firm engaged in management consulting and expert support to clients worldwide. CRA's Energy Practice was formed in the late 1980s with much of the initial focus on electricity and gas markets development. Since that time, CRA has expanded into strategy, planning, and transaction support, primarily for electric utilities and energy conglomerates.

One of CRA's major service areas for the last twenty years has been electric utility resource planning and strategy. CRA provides end-to-end IRP services, including scorecard development, commodity price forecasting, technology analysis, load analysis, energy efficiency program analysis, scenario development and analysis, portfolio formation and modeling, portfolio risk analysis, technical volume development, testimony development, and stakeholder engagement. The firm has experts in key functional subject matters areas including electricity and gas markets, load forecasting and demand response, power technologies, portfolio modeling, financial revenue requirement analysis, and advanced analytics including stochastics. CRA licenses and develops models to evaluate complex resource decisions, including Aurora and its proprietary financial module.

CRA has extensive resource planning experience across the United States and particularly in the MISO market, with recent work focused on developing commodity price forecasts, performing portfolio analysis, and conducting stakeholder engagement processes. Over the last two years, in addition to CRA's work with IPL, the firm has provided analysis and consulting support for the following MISO utilities: Wisconsin Power and Light, Northern Indiana Public Service Company, Great River Energy, Hoosier Energy, Minnkota Power Cooperative, and DTE.

As a firm founded on principles of applied economics, CRA's staff is highly trained in economic and market analysis, with expert witness testimony experience present across much of the senior team. Brief biographies of the core CRA staff members that contributed to the resource planning efforts associated with IPL's Clean Energy Blueprint are provided below.

Jim McMahon

Jim McMahon is a Vice President in CRA's energy practice with approximately twenty years of experience in management consulting to utilities. Jim regularly consults to North American utilities on strategy, capital allocation, and business planning. He has advised electric and gas utilities – large and small - on major infrastructure investment decisions, including generation investment, T&D replacement and modernization, and gas midstream investment. He frequently leads teams at CRA that model the complex interactions of utility assets in electricity markets and distills results into actionable financial and qualitative analytics. Jim also frequently facilitates meetings with utility teams and has led numerous stakeholder sessions at the public utilities commission. Jim holds a JD and MBA from the College of William and Mary, and a BA in Economics from Tufts University.

Patrick Augustine

Patrick Augustine is a Vice President in CRA's Energy practice, with fifteen years of experience in the electric industry, specializing in market analysis and strategy development within the utility and power market sectors. Pat is experienced with power market dispatch systems and utility planning tools and has performed and managed power market assessments throughout North America in support of project developers, utilities, investors, and lenders in their development, financing, and planning efforts. He has worked for dozens of electric utilities in support of their resource planning and strategy development activities and has extensive experience assessing and designing portfolio modeling techniques and processes. He has testified in state regulatory proceedings related to resource planning and power market analysis in Indiana, Michigan, Ohio, and Kentucky. Pat holds a master's degree in environmental management from Duke University and a BA from Harvard University.

Natasha Turkmani

Natasha Turkmani is an Associate in CRA's Energy Practice. Her primary focus at CRA is power market modeling using Aurora, with particular emphasis on utility portfolio analysis and revenue requirement accounting. Prior to joining CRA, she completed her Master's in Energy Technologies from Cambridge University as a Gates Cambridge Scholar. She holds a BA from Princeton University.

John Garvey

Jack Garvey is a Consulting Associate in CRA's energy practice. Jack specializes in both power market modeling and financial modeling. He manages CRA's financial revenue requirement processes and has performed a variety of economic and financial modeling analyses on behalf of multiple investor owned utility clients to support resource planning, rate forecasting, generation strategy, and tax equity related exercises. Jack holds a BA from Boston College and is currently pursuing an MBA at the University of Chicago.

Jonathan Painley

Jonathan Painley is a Senior Associate in CRA's Energy Practice specializing in market analysis and strategy development within the utility and power market sectors. Jonathan has supported utilities, project developers, investors, and lenders in their development, financing, planning, and risk analysis efforts. Jonathan manages input assumptions, model setup, and execution of Aurora dispatch software to capture North American power market fundamentals and produce long-term assessments of generation portfolios. Prior to joining CRA, he was a Summer Associate at CenterPoint Energy and a Process Engineer at a biodiesel refinery and a cogeneration power plant. Jonathan holds an MBA from the University of Texas at Austin and an BS from North Carolina State University.