2023 Integrated Resource Plan

February 1, 2024

Indiana Municipal Power Agency

The opinions expressed in this report are based on Indiana Municipal Power Agency's estimates, judgment and analysis of key factors expected to affect the outcomes of future energy, capacity, and commodity markets and resource decisions. However, the actual operation and results of energy markets may differ from those projected herein.

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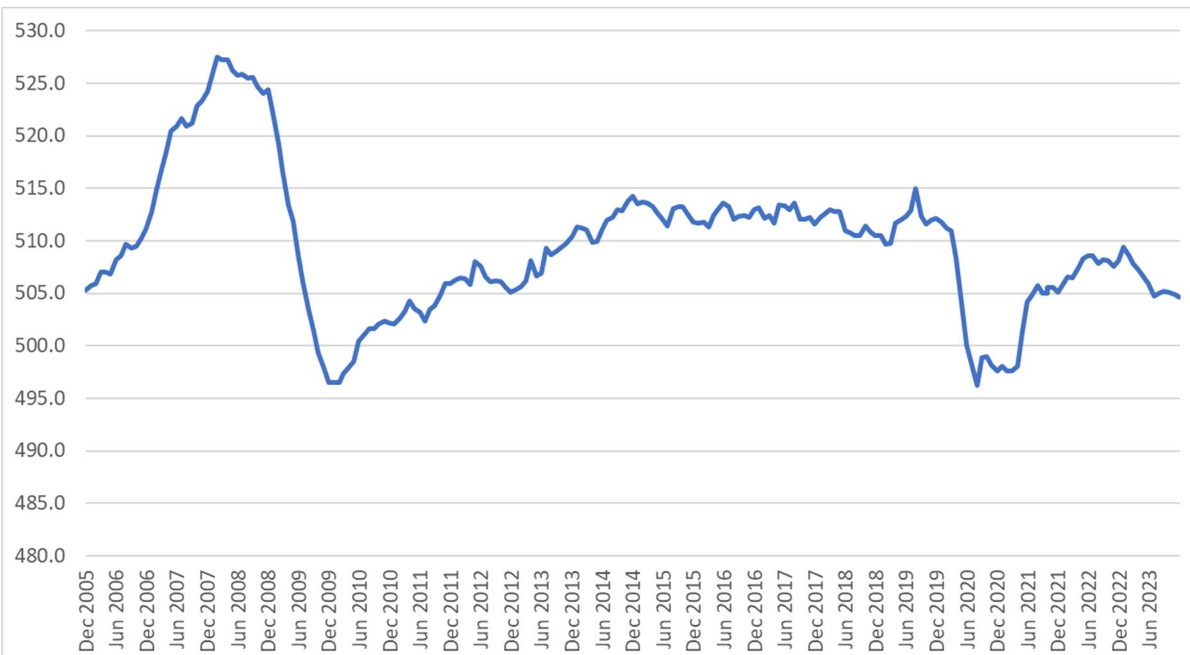
1 PREFACE

In IMPA's 2020 Integrated Resource Plan (IRP), Indiana Municipal Power Agency (IMPA) discussed the "unprecedented uncertainty" being faced by utility planners. At that time, the principal concern was one of pandemic related demand destruction and load forecast uncertainty around a potential economic recovery. As uncertainty surrounding economic recovery lifted, a host of new issues arose as the world economy emerged from the pandemic: Supply chain shortages, inflationary pressures, backlogged generation interconnection queues, reforms centered resource adequacy within the Independent System Operators (ISO) / Regional Transmission Organizations (RTO) framework, and competing/conflicting environmental goals.

On a monthly basis, IMPA tracks its member loads on a weather corrected basis in order to gauge potential changes in growth patterns related to economic growth. In late 2020 and early 2021, IMPA began to see a sharp uptick in weather corrected loads, signaling a rebound in load when compared to losses seen during the pandemic.

Figure 1 IMPA Weather Adjusted Load (GWh)



Recent trends suggest the start of some potential demand destruction after a relatively swift post pandemic recovery. These trends vary by area, with the IMPA AEP load zone seeing roughly .3% growth from 2014 through the end of 2023. However, this is offset by modest declines in the other four load zones IMPA serves. IMPA is continuing to investigate the source of these declines.

With COVID uncertainty abating, other storm clouds were gathering. As part of IMPA's 2020 action plan, IMPA stated it would "Explore incremental opportunities for solar off-take as part of the modeled, least cost solution." IMPA subsequently issued a RFP to canvass the market for potential projects. A project was selected and IMPA entered into negotiations with the selected developer. By Q2, 2021, the developer had backed away from initial pricing due to interconnection cost risk stemming from the Midcontinent Independent System Operator (MISO)'s generation interconnection queue.

Despite best efforts to find middle ground, IMPA and the short-listed developer parted ways by mid-2021. IMPA was then forced to run a new RFP, from which a project was to be selected. With a new project selected, IMPA executed new agreements. However, with growing uncertainty around MISO interconnection costs and equipment supplies, the developer was understandably concerned with being able to hold pricing. By late 2022, a re-negotiation was requested by the developer, with new pricing being 60% higher than the pricing received in the initial RFPs.

Concurrent to renewable power supply procurement challenges, ISO/RTOs greatly revamped their resource adequacy construct rules since the last IRP. MISO began by moving from a one season auction to a four-season auction with individual planning reserve margins while PJM is in the midst of its resource adequacy construct redesign. PJM, for now, seems to be headed towards a two season construct in contrast to MISO's four-season construct. MISO's construct poses a set of more immediate challenges to resource planning for IMPA.

MISO took steps to first implement a seasonal capacity auction for Planning Year 23/24. Two key features of this auction were newly implemented reserve margins and a change in how resources were accredited for their capacity contribution. The reserve margins for the first MISO Seasonal Capacity Auction (PY 23-24) are shown in Figure 2.

Figure 2 MISO Seasonal Capacity Auction Reserve Margins

Season	PY 19-20	PY 20-21	PY 21-22	PY 22-23	PY 23-24
Summer	7.9%	8.9%	9.4%	8.7%	7.4%
Fall	7.9%	8.9%	9.4%	8.7%	14.9%
Winter	7.9%	8.9%	9.4%	8.7%	25.5%
Spring	7.9%	8.9%	9.4%	8.7%	24.5%

While the summer season saw a slight decline in reserve margin, other seasons were markedly higher, particularly for the winter and fall seasons. When taken in conjunction with new resource accreditation rules, the planning focus shifts more towards winter requirements and reliability concerns in those months.

To that end, MISO moved resource accreditation from a methodology that is essentially an unforced capacity (UCAP) approach, to an approach that credits capacity based on how a particular generator performs during periods of market stress. These are called Resource Adequacy Hours, or RA Hours and they represent periods of "greatest need" during a season in a given planning year. They include both Emergency Declaration periods and periods when operating margins are at their lowest.[1] While MISO essentially blends accreditation values across emergency hours and non-emergency hours, it makes predicting and planning the resource portfolio challenging.

Additional complications arise as MISO continues to revise market rules around the seasonal capacity auction. The most recent proposal involves a Direct Loss of Load (DLOL) approach that credits capacity based on both market simulations and on how that capacity performed during modeled loss of load events. This would then set technology specific baselines for capacity credit with individual resources getting a bonus or decrement based on their real-world performance over prior RA Hours.

Under this capacity construct, the largest impact to resource accreditation would be to solar generation. Previously, solar generation was granted an initial class average of 50% capacity credit until enough performance data had been gathered, at which point performance during hours 13-15 were used to determine capacity credit.
Under DLOL approaches being proposed in a seasonal construct, solar takes a material reduction in capacity credit during the summer season and is credited with negligible credit during the winter season. [2]

[1] https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc
[2] https://cdn.misoenergy.org/20230711-12%20RASC%20Item%2008ai%20Resource%20Accreditation%20Presentation%20(RASC-2020-4,%202019-2)629479.pdf

Figure 3 Resource Accreditation Changes by Resource Class

	Summer		Fall		Winter		Spring	
Resource Class	UCAP	DLOL	UCAP	DLOL	UCAP	DLOL	UCAP	DLOL
Gas	91%	89%	89%	89%	84%	70%	88%	74%
Coal	92%	91%	91%	88%	90%	72%	89%	75%
Hydro	97%	97%	97%	99%	42%	68%	62%	70%
Nuclear	95%	91%	96%	86%	95%	87%	92%	80%
Pumped Storage	99%	98%	91%	97%	94%	57%	89%	75%
Solar	45%	37%	25%	27%	6%	1%	15%	17%
Wind	18%	12%	23%	15%	40%	14%	23%	18%
Storage	95%	94%	95%	94%	95%	94%	95%	95%
Run of River	100%	100%	100%	100%	100%	100%	100%	100%

While PJM's capacity market construct is being redesigned, it remains to be seen what, if any changes occur to renewable energy accreditation in the PJM construct. However, if the MISO market reforms are a prologue to the PJM reforms, it seems clear that ISOs and RTOs are moving away from a framework that is based on traditional peak load + reserves and moving towards a framework that sets future capacity obligations based on emergency events or periods of time when operating reserves are at their lowest. As renewable generation penetration increases in the market, this implies that the capacity obligation may occur at times the sun is not shining, and the wind is not blowing.

Finally, in the midst of market rule changes designed to enhance and protect the reliability of grid delivered power, utilities are also facing divergent policy making designed to limit CO_2 emissions. Specific to IMPA, ownership of the Prairie State Generating Campus subjects the IMPA portfolio to the Illinois Climate & Equitable Jobs Act (CEJA), while the Environmental Protection Agency (EPA) recently proposed new carbon standards for coal and natural gas fired power plants. The proposed EPA rules would effectively accelerate coal retirements and force baseload gas fired units (i.e., combined cycle units) to either equip units with carbon capture or blend their gas with hydrogen. Natural gas peaking units face far fewer restrictions, however.

IMPA's mission is to supply wholesale power to its 61 communities that is low-cost, reliable, and environmentally responsible. The balance of this document will demonstrate what IMPA believes is its best path forward to accomplish this mission.

2 EXECUTIVE SUMMARY

The Indiana Municipal Power Agency (IMPA) is a body corporate and politic and political subdivision of the State of Indiana, operating as a wholesale electric utility serving the total electricity requirements of 61 communities under long-term power sales contracts. Each of IMPA's 61 members is a city or town with a municipally owned electric distribution utility. IMPA regularly reviews its projected loads and resources in order to ensure it is planning to meet its members' long-term load requirements in an economical, reliable and environmentally responsible manner. These planning activities are required under IMPA's risk management framework and are necessary to participate in the Regional Transmission Organization (RTO) markets. Pursuant to the requirements of 170 IAC 4-7, IMPA presents its 2023 Integrated Resource Plan (IRP). This report assesses IMPA's options to meet its members' capacity and energy requirements for wholesale service from 2024 through 2043.

Integrated resource planning involves the consideration of both supply-side and demand-side resources to meet the future resource needs of an electric utility and its customers. IMPA's primary objective in developing its IRP is to minimize the price of electricity to its member utilities and their customers, while maintaining a reliable and environmentally responsible electricity supply. Additional objectives include minimizing risk through diversifying resources and fuel and maintaining flexibility to respond to changing economic and regulatory conditions.

In 2022, IMPA's coincident peak demand for its 61 communities was 1,205 MW, and the annual member energy requirements during 2022 were 6,193,499 MWh. IMPA projects that its peak and energy will grow at less than 0.30% per year. These projections do not include the addition of any new members or customers beyond those currently under contract.

IMPA currently uses both supply and demand-side resources to meet its customer peak demand and energy requirements. Current resources include:

- Joint ownership interests in Gibson Station 5, Trimble County Station 1 & 2, and Prairie State Energy Campus 1 and 2;
- Control, operation and maintenance responsibility of Whitewater Valley Station 1 & 2;
- Five (5) dual fuel, natural gas or No.2 fuel oil, fired combustion turbines owned and operated by IMPA;
- Two (2) natural gas fired combustion turbines owned by IMPA and operated by AES Indiana (AES);
- 50 Solar Parks located in member communities;

- Long-term power purchases from:
    - Indiana-Michigan Power Company (I&M)
    - Alta Farms II Wind Farm LLC
    - Ratts Solar Park LLC (COD 2025)
- Short term contracts with market participants in MISO and/or PJM;
- The IMPA Energy Efficiency Program

IMPA's existing resources are diverse in terms of size, fuel type and source, geographic location, and vintage. IMPA owns or controls generation in MISO and PJM as well as in the Louisville Gas & Electric/Kentucky Utilities (collectively LG&E) control area. IMPA's generation and contractual resources reside in Indiana, Illinois, and Kentucky. This diversity reduces IMPA exposure to forced outages, locational marginal prices (LMPs), zonal capacity rates, and regional fuel costs.

IMPA's energy efficiency program offers incentives in the form of rebates for residential and commercial and industrial (C&I) customers. Since 2012, IMPA's energy efficiency programs generated a cumulative savings of 121,033 MWh at the end of 2022 and a coincident peak reduction of 13.6 MW. In addition to its energy efficiency program, IMPA offers a demand response tariff, an excess renewable generation program, education, and training. Furthermore, many IMPA members utilize various rate structures aimed at assisting customers in lowering or controlling their energy consumption or bills.

As discussed in the body of this report, IMPA has considered a variety of potential resources. These are discussed more fully in Section 7. IMPA's analysis has identified a plan that allows it to economically meet its members' future load growth while limiting future risks due to unforeseen legal or regulatory outcomes. The description of the modeling, planning process, and plan selection are discussed in Sections 10 through 13.

2.1 ACTION PLAN

IMPA's preferred resource expansion plan is shown below.

Table 1 2023 IRP Expansion Plan - Preferred Plan

Date	Resource	ISO	+/- MW (ICAP)	+/- MW (Summer UCAP)	+/- MW (Winter UCAP)
Jan 2025	Demand Response*	MISO	2	2	2
Jul 2025	Ratts Solar	MISO	150	55	2
May 2026	Existing Bilateral Capacity	MISO	(75)	(75)	(75)
Jun 2026	New Bilateral Capacity - 5 yr Term	MISO	200	200	200
Jan 2028	Gibson 5 Retirement	MISO	(156)	(121)	(106)
Jan 2029	Solar PPA	MISO	50	19	1
Jan 2029	WWVS	PJM	(90)	(73)	(73)
Jan 2030	Solar PPA	PJM	50	19	1
Jan 2031	Solar PPA	PJM	50	19	1
Jan 2031	IMPA Self Build CT COD	MISO	239	201	208
May 2031	New Bilateral Capacity - 5 Yr Term	MISO	(200)	(200)	(200)
Jan 2032	Solar PPA	PJM	50	19	1
Jan 2033	Solar PPA	PJM	50	19	1
Jan 2034	Wind PPA	PJM	100	15	15
Jun 2034	AEP Contract	PJM	(190)	(190)	(190)
Jun 2034	Planned Combined Cycle	PJM	100	100	110
*** Demand Response is assumed to grow at a 2 MW per year in enrollments, maxing out at 10 MW**					

IMPA is expected to have a mostly flat capacity position over 20-year planning horizon if the preferred plan is acted on. Due to the newly seasonal nature of capacity markets, IMPA's position is expected to be long in the summer months, assuming no degradation of solar accreditation. The winter position is expected to be only slightly short under the preferred plan, with a maximum short position of about 60 MW. This position is small enough to be hedged in bilateral capacity markets or could be absorbed by better-than-expected demand response enrollments.

Action Plan Items

1. Work with the Gibson 5 partners regarding the final plan, timing, and cost for retirement of the unit.
2. Begin internal planning for the best path forward for adding CT capacity to its portfolio as a replacement for Gibson 5.
3. Execute 200 MW capacity bilateral contract.
4. Maintain regular contact with the marketplace for both financial and physical power.
5. Maintain regular contact with the renewable energy market to evaluate potential utility scale projects that may benefit the power supply portfolio.
6. Continue the IMPA Energy Efficiency Program and implement revised demand response program.
7. Continue to utilize the RTO/ISO stakeholder process to monitor market rules regarding renewable capacity accreditation and resource adequacy.
8. Monitor elections and the legislative process to remain informed on future legislative and regulatory policy as it pertains to CO_2.
9. Continue to enhance IMPA's modeling capabilities with respect to transmission, capacity/market price formation, and portfolio optimization.

In IMPA's previous IRPs, IMPA has seen the best fit resource as a combustion turbine for the replacement of Gibson 5. With the retirement of Gibson 5 fast approaching, IMPA intends to coordinate with the Indiana Utility Regulatory Commission (IURC), on meeting all regulatory requirements to pursue the construction of a natural gas fired combustion turbine in the 2030 time frame.

3 IMPA OVERVIEW

3.1 Introduction

Pursuant to Indiana Code § 8-1-2.2-1 *et seq*., IMPA was created in 1980 by a group of municipalities to undertake the planning, financing, ownership, and operation of projects to supply electric power and energy for the present and future needs of the members. IMPA began operation in 1983 with 24 members. IMPA now serves 61 members in Indiana and Ohio. Pursuant to the power sales contract with each of its members, IMPA is the wholesale full requirements power provider for its members. While IMPA's members serve a population of over 330,000 people, IMPA has no retail customers itself.

3.2 Key Events Since Last IRP

Since IMPA submitted its last IRP to the IURC on November 2nd, 2020 the following events have taken place:

- Continued the IMPA Solar Park program, installing 18 parks in 12 communities:
  - 2021 – 6 Parks – 49.1 MW
  - 2022 – 5 Parks – 22.8 MW
  - 2023 – 7 Parks – 24.7 MW
- In August 2022 IMPA closed on the sale of its Power Supply Revenue Bonds, 2022 Series A. The purpose of these bonds was to fund capital improvements on existing Agency assets.
- In December of 2022 IMPA closed on the buyback of the Anderson 1 solar park.
- In May of 2023, the Alta Farms II wind farm began commercial operations.
- In September of 2023, the amended and restated Ratts 1 Solar LLC contract was signed.
- In December of 2023 IMPA closed on the buyback of the Anderson 2, Greenfield, Flora, and Spiceland solar parks.

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4 IRP OBJECTIVES AND PROCESS

4.1 IRP RULES (170 IAC 4-7)

The IURC developed guidelines in 170 IAC 4-7-1 *et seq*. for electric utility IRPs to assist the IURC in its administration of the Utility Powerplant Construction Law, IC 8-1-8.5. IMPA and seven other utilities across the state of Indiana are subject to the IRP rules.

4.2 IMPA IRP OBJECTIVES

Integrated resource planning involves the consideration of both supply-side and demand-side resources to meet the future resource needs of an electric utility and its customers. IMPA's primary objective in developing its IRP is to minimize the price of electricity to its member utilities and their customers, while maintaining a reliable and environmentally responsible electricity supply. Additional objectives include minimizing risk through a diverse mix of resources and maintaining flexibility to respond to changing economic and regulatory conditions.

4.3 IMPA PLANNING CRITERIA

IMPA serves wholesale load in both MISO and PJM and must comply with the resource adequacy requirements of each RTO for its load in that RTO. In addition, loads are adjusted for area specific transmission loss factors, consistent with MISO and PJM capacity construct methodologies. From a resource planning standpoint, resource capacity was determined to be seasonal ratings for thermal resources, adjusted by observed or class average equivalent forced outage rate (EFORd), while wind was set to 15% of nameplate. At the time of modeling, MISO had put more discussion into solar resource accreditation than wind, thus wind was assumed to only get its previously allowed credit. Solar is given seasonal capacity credit based on currently contemplated market rules, using a proposed DLOL methodology. This results in capacity credit for solar ranging from 37% in the summer to as low as 1% in the winter.

IMPA plans its resources to meet its projected load and does not allow the expansion models to add resources for speculative sales. IMPA does allow the model to purchase market capacity in the future, but these are limited to small quantities and meant to simulate the normal final balancing that takes place in today's RTO capacity markets. This buffer also allows flexibility in the future regarding load uncertainty, energy efficiency, demand response, and renewables development.

4.4 IMPA Planning Process

Formulating an IRP is a multistep project that utilizes many disciplines, including engineering, environmental science, statistics, and finance. The basic steps of the IRP process are summarized below, with references to where further information can be found in this document.

1. Evaluation of Existing System – Establishes the basis for future resource planning by identifying the expected future availability of existing supply-side and demand-side resources, including possible upgrades, expansions, or retirements of those resources (Section 5).

2. Long Range Forecast Development – Annually, IMPA develops a 20-year projection of peak demands and annual energy requirements. The load forecast is developed using a time-series, linear regression equation for each load zone (Section 6).

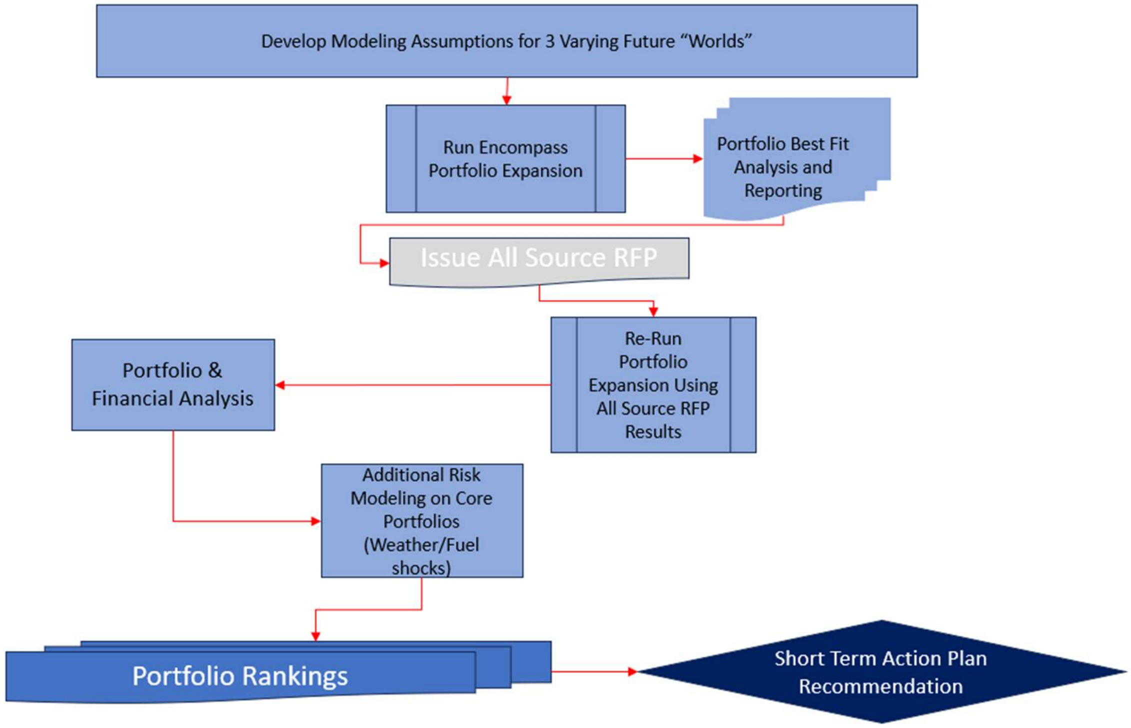
3. Resource Options and Environmental Compliance – This step involves the description of various resource alternatives. Additionally, transmission service and compliance with future environmental issues are discussed (Sections 7-9).

4. Software Overview / Data Sources – This section describes the software and data sources used to perform the analysis (Section 10).

5. Scenario Development, Assessment, and Evaluation – IMPA creates scenarios as a structured way to think about the future, as scenario planning is a proven tool to better anticipate and respond to future risks and opportunities. After scenarios have been established, IMPA modeling efforts center around building the most efficient portfolio of resources for a given scenario. From those portfolios, various risks and stress tests can be run. A crucial part of the IRP process is evaluating how a portfolio performs under various risk drivers and its ability to absorb risk (Section 12-15).

   As a broad overview, IMPA utilizes Encompass by Anchor Power Solutions for its power supply modeling and MCR-FRST by MCR Performance Solutions for financial modeling. The flowchart on the following page illustrates the general process for modeling the IRP.

Figure 4 IRP Flow Chart



The process begins with scenario development and their underlying assumptions. From those assumptions IMPA utilizes Encompass to run portfolios against forecast market forward prices for commodities, along with any environmental constraints. Encompass optimizes the portfolio to be the lowest cost possible while maintaining assumed reserve margins for each area. Supply resources at this stage of the process are largely "academic" and based on a combination of EIA cost estimates for new generation and other market-based observations.

6. Once best fit determinations have been made from model optimization, IMPA then issues an All-Source RFP seeking the resources the initial optimization suggested.
7. The Encompass model is then updated with the All-Source RFP projects and a new optimization is run.

From these new optimizations, final candidate portfolios are constructed and then assessed based on their various portfolio characteristics.

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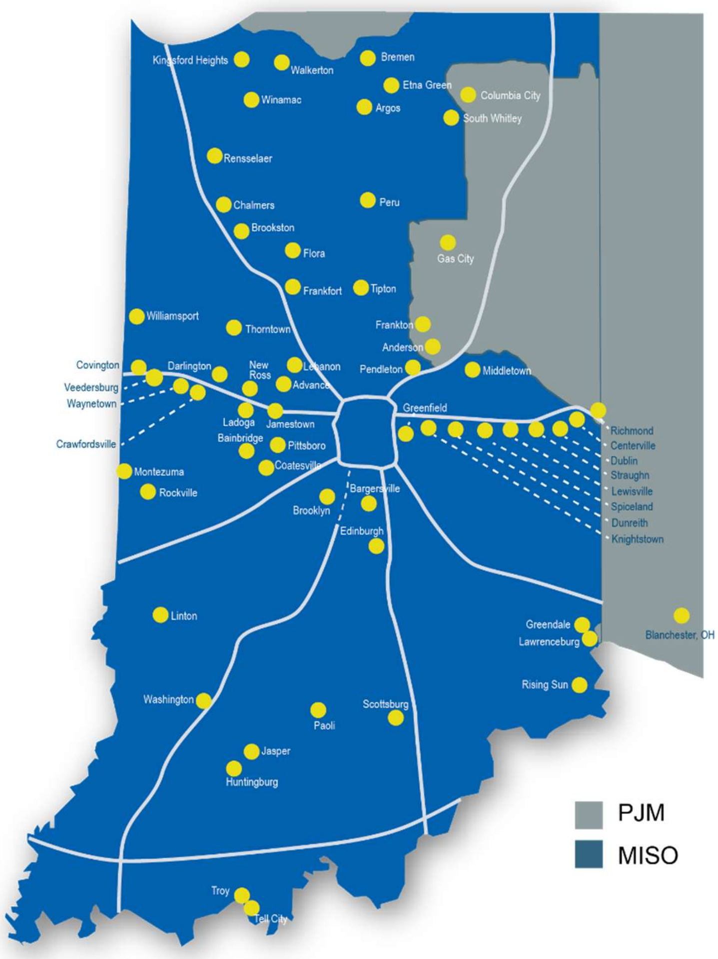
5 EXISTING SYSTEM

5.1 IMPA SYSTEM DESCRIPTION

IMPA is a body corporate and politic and political subdivision of the State of Indiana, operating as a wholesale electric utility serving the total electricity requirements of 61 communities. IMPA has no retail customers and no direct communication or other interaction with the member's retail customers, except as specifically requested by the member. Each of IMPA's 61 members is a city or town with a municipally owned electric distribution utility.

IMPA operates in both the MISO and PJM RTOs. IMPA has member load in five load zones and generation resources connected to six zones within the RTO footprints, plus two resources outside of the RTOs. IMPA's load is divided approximately two-thirds within the MISO footprint and one-third in PJM.

Figure 5 IMPA Communities Map



5.2 Loads and Load Growth

IMPA's member communities are located in five different load zones in MISO and PJM. When IMPA began operations in 1983, it served 24 communities. IMPA now serves 61 communities. The following table lists the 61 communities that IMPA serves along with the RTO and load zone in which they are located and the approximate percentage of IMPA's total load.

Table 2 IMPA Communities

RTO	Load Zone	% of Load	Community
MISO	Duke-IN	50%	Advance, Bainbridge, Bargersville, Brooklyn, Brookston, Centerville, Coatesville, Covington, Crawfordsville, Darlington, Dublin, Dunreith, Edinburgh, Flora, Frankfort, Greendale, Greenfield, Jamestown, Knightstown, Ladoga, Lawrenceburg, Lebanon, Lewisville, Linton, Middletown, Montezuma, New Ross, Paoli, Pendleton, Peru, Pittsboro, Rising Sun, Rockville, Scottsburg, South Whitley, Spiceland, Straughn, Thorntown, Tipton, Veedersburg, Washington, Waynetown, Williamsport
	NIPSCO	7%	Argos, Bremen, Chalmers, Etna Green, Kingsford Heights, Rensselaer, Walkerton, Winamac
	Centerpoint/Vectren	10%	Huntingburg, Jasper, Tell City, Troy
PJM	AEP-I&M	32%	Anderson, Columbia City, Frankton, Gas City, Richmond
	Duke-OH	1%	Blanchester, Ohio

In 2022, IMPA's peak demand for its 61 communities was 1,205 MW, and the annual member energy requirements were 6,193,499 MWh.

Hourly loads are shown in Appendix A and typical annual, monthly, weekly, and daily load shapes for IMPA are shown in Appendix B. As a wholesale supplier, IMPA does not have the necessary retail load information to draw conclusions concerning disaggregation of load shapes by customer class or appliance.

5.3 EXISTING SUPPLY-SIDE RESOURCES

IMPA currently has a variety of supply-side resources, including:

- Joint ownership interests in Gibson Unit 5, Trimble County Units 1 and 2, Prairie State Units 1 and 2;
- Control, operation, and maintenance responsibilities for Whitewater Valley Units 1 and 2;
- Seven combustion turbines wholly owned by IMPA;
- 50 solar parks located in IMPA member communities;
- Long-term power purchases from I&M, as well as short term purchases from various utilities, power marketers, and exchanges in the MISO and PJM energy markets.
- Alta Farms II Wind Farm LLC
- Ratts Solar Park LLC (COD: 2025)

Some of these resources have contractual limitations that restrict their use to a particular balancing area or delivery point. Tables summarizing the key characteristics of IMPA's generating units and long term purchased power agreements are shown in Appendices D1 and D2. The resources and contracts are described in more detail on the following pages.

Gibson 5

IMPA has a 24.95% ownership interest in Gibson 5, which it jointly owns with Duke Energy Indiana (DEI) (50.05%) and Wabash Valley Power Alliance (WVPA) (25.00%). Gibson 5 is a 625 MW coal-fired generating facility located in southwestern Indiana. It is equipped with particulate, Hg, SO_2, and NO_x removal facilities (selective catalytic reduction (SCR) system), and an SO_3 mitigation process. The boiler has also been retrofitted with low NO_x burners. The fuel supply for Gibson Station is acquired through a number of contracts with different coal suppliers. The coal consists of mostly high sulfur coal sourced from Indiana and Illinois mines. A small amount of low sulfur coal is also purchased. DEI has multiple coal contracts of varying lengths to supply the five units at Gibson Station. Procurement is such that the prompt year's supply is nearly completely hedged while future years are partially contracted two to three years in advance. Coal is delivered by both train and truck. The current targeted stockpile inventory is 45-50 days.

DEI operates Gibson 5 under the "Gibson Unit No. 5 Joint Ownership, Participation, Operation, and Maintenance Agreement" (Gibson 5 Agreement) among DEI, IMPA, and WVPA. The Gibson 5 Agreement obligates each owner to pay its respective share of the capital, and operating costs of Gibson 5 and entitles each owner to its respective share of the capacity and energy output of Gibson 5.

As of the date of this report, this unit is scheduled to be retired on May 31, 2030. This information was not known at the time of modeling and the unit was allowed to retire economically in the model. That date was January 1st. 2028. Due to the jointly owned nature of the unit, IMPA cannot unilaterally exit its share of the unit prior to the agreed upon retirement date.

Trimble County 1

IMPA has a 12.88% ownership interest in Trimble County 1, which is jointly owned with LG&E (75.00%) and the Illinois Municipal Electric Agency (IMEA) (12.12%). Trimble County 1, commissioned in 1990, is a nominal 490 MW coal-fired generating unit located in Kentucky on the Ohio River, approximately 15 miles from Madison, Indiana. This subcritical unit is equipped with low-NO_x burners, an SCR system, a dry electrostatic precipitator, activated carbon injection, a pulse jet fabric filter, an SO_3 mitigation process, and wet flue gas desulfurization. Trimble County 1 burns high sulfur coal. LG&E purchases coal on a system basis and delivers it to its various power plants. The majority of this coal is from mines in Indiana and Kentucky. All coal is delivered to Trimble County by barge. Due to barge delivery, stockpile inventory levels fluctuate within a targeted 28-49 day level.

LG&E operates Trimble County 1 under the "Participation Agreement By and Between LG&E, IMEA, and IMPA" (Trimble County 1 Agreement). The Trimble County 1 Agreement obligates each owner to pay its respective share of the operating, and capital costs of Trimble County 1 and entitles each owner to its respective share of the capacity and energy output of Trimble County 1. Transmission service is provided from the plant to the LGEE-MISO interface.

Trimble County 2

IMPA has a 12.88% ownership interest in Trimble County 2, which is jointly owned with LG&E/KU (75.00%) and the IMEA (12.12%). Trimble County 2, commissioned in 2011, is a nominal 760 MW coal-fired generating unit located in Kentucky on the Ohio River, approximately 15 miles from Madison, Indiana. This supercritical unit is equipped with low-NO_x burners, an SCR system, a dry electrostatic precipitator, activated carbon injection, a pulse jet fabric filter, an SO_3 mitigation process, wet flue gas desulfurization, and a wet electrostatic precipitator. Trimble County 2 burns a blend of high- and low- sulfur coals. LG&E purchases coal on a system basis and delivers it to its various power plants. The majority of the high-sulfur coal is from mines in Indiana and Kentucky. The low-sulfur coal is western sub-bituminous coal. All coal is delivered to Trimble County by barge. Due to barge delivery, stockpile inventory levels fluctuate within a targeted 28-49 day level.

LG&E operates Trimble County 2 under a the "Participation Agreement By and Between LG&E, Kentucky Utilities, IMPA, and IMEA" (Trimble County 2 Agreement). The Trimble County 2 Agreement obligates each owner to its respective share of the capacity and energy output of Trimble County 2. Transmission service is provided from the plant to the LGEE-MISO interface.

Prairie State Energy Campus

IMPA has a 12.64% ownership interest in the Prairie State Energy Campus (PSEC), which is jointly owned with eight other public power entities. PSEC is located in the southwest part of Washington County, Illinois, approximately 40 miles southeast of St. Louis, Missouri. PSEC consists of Prairie State Units 1 & 2, related electric interconnection facilities, the Lively Grove mine, the near-field coal combustion residuals (CCR) disposal facility, and the Jordan Grove CCR disposal facility.

Prairie State Units 1 & 2, which began commercial operation in 2012, are each nominal 800 MW pulverized coal-fired generating units. These supercritical units are each equipped with low-NO_x burners, an SCR system, a dry electrostatic precipitator, an SO_3 mitigation process, wet flue gas desulfurization, and a wet electrostatic precipitator. The generating units are supplied coal from the adjacent Lively Grove mine (also part of PSEC). The PSEC-owned coal reserves were planned for a 30-year supply and are estimated to be able to supply the coal required by the plant for the foreseeable life of the asset, assuming CEJA limits the life of the asset.

The Prairie State Generating Company (PSGC) was created by the owners of the PSEC to operate all aspects of the PSEC. The nine owners of PSEC direct PSGC in operating and maintaining the PSEC.

As of the date of this report, PSEC is subject to the State of Illinois Climate and Equitable Jobs Act (CEJA). This requires the generating units to reduce CO_2 emissions by 45% by January 1, 2038 and by 100% by December 31, 2045.

White Water Valley Station

On June 1, 2014, IMPA entered into an amended and restated capacity purchase agreement with Richmond Power & Light, obtaining the rights to operate and maintain White Water Valley Station (WWVS). WWVS consists of two pulverized coal-fired generating units with a current maximum tested capabilities of approximately 30 MW and 60 MW, respectively. These subcritical generating units are each equipped with low-NOx burners, an overfire air system, dry sorbent injection, activated carbon injection, dry electrostatic precipitators, and a fabric filter baghouse. IMPA purchases coal on a short-term, spot market basis to support the operation of the plant, which is generally used to fulfill peaking needs.

Due to EPA's proposed Effluent Limitations Guidelines rule, WWVS is assumed to be retired by December 31st, 2028.

IMPA Combustion Turbines

IMPA owns seven combustion turbines at three sites. Three units are located in Anderson, Indiana (Anderson Station), two units are located near Richmond, Indiana (Richmond Station), and two units are located at the Georgetown Combustion Turbine Station in Indianapolis, Indiana (Georgetown Station).

IMPA operates and maintains the Anderson and Richmond Stations with on-site IMPA personnel. Each site has two GE 6B turbines; Anderson Unit 3 is a GE 7EA turbine. These generating units use either dry low-NO_x combustors and/or water injection for NOx compliance. These units operate primarily on natural gas, with No. 2 fuel oil available as an alternate fuel. Natural gas is delivered under an interruptible contract with CenterPoint (Vectren). This contract gives IMPA the option to obtain its own gas supplies from various sources with gas transportation supplied by CenterPoint (Vectren). IMPA maintains an inventory of No. 2 fuel oil at each station.

IMPA is the sole owner of Units 2 and 3 at the Georgetown Station. AES Indiana operates and maintains these two units for IMPA. The units are both GE 7EA turbines and operate solely on natural gas. They maintain NOx compliance with dry low-NO_x combustors. Citizens Energy Group delivers natural gas to the Georgetown Station from the Panhandle Eastern Pipeline system. AES Indiana has the responsibility to ensure IMPA's units comply with applicable environmental requirements.

IMPA Solar Parks

In 2013, IMPA began a program to construct photovoltaic solar parks in member communities. By the end of 2023, 50 facilities totaling 194.7 MW had been placed in service. These solar parks range in size from 0.24 to 9.90 MW. Continued development of solar parks is planned through 2025.

IMPA solar parks are currently operating in the following communities:

Table 3 IMPA Solar Parks

Facilty	MW			Facilty	MW	
Advance	0.24	(PPA)		Ladoga	0.60	
Anderson	4.90			Linton	5.38	(PPA)
Anderson 2	8.35			Middletown	1.35	
Anderson 3	8.70	(PPA)		Pendleton	2.01	
Anderson 4	7.80	(PPA)		Peru	3.02	
Anderson 5	3.00	(PPA)		Peru 2	9.45	(PPA)
Anderson 6	6.75	(PPA)		Peru 3	2.85	(PPA)
Argos	0.71			Rensselaer	1.00	
Bainbridge	0.35			Rensselaer 2	3.85	(PPA)
Bremen	6.75	(PPA)		Richmond	1.00	
Centerville	1.05	(PPA)		Richmond 2	7.40	(PPA)
Columbia City	4.25	(PPA)		Richmond 3	6.39	(PPA)
Crawfordsville	2.98			Richmond 4	7.05	(PPA)
Crawfordsville 2	7.57	(PPA)		Richmond 5	9.15	(PPA)
Crawfordsville 3	4.54	(PPA)		Richmond 6	5.33	
Crawfordsville 4	2.32	(PPA)		Richmond 7	4.35	
Crawfordsville 5	9.66	(PPA)		Scottsburg	6.95	(PPA)
Darlington	0.90	(PPA)		Spiceland	0.51	
Flora	0.79			Tell City	1.05	
Frankton	0.99			Tell City 2	3.09	(PPA)
Gas City	2.44	(PPA)		Tipton	5.16	(PPA)
Gas City 2	1.80			Walkerton	1.05	(PPA)
Greenfield	2.78			Washington	3.57	
Huntingburg	2.03			Washington 2	9.90	
Knightstown	1.35			Waynetown	0.27	

(PPA) - Facility was developed, designed and constructed by IMPA, but sold to a third-party. IMPA purchases 100% of the output from the solar park under a long term PPA with the third party.

Firm Power Purchases

On January 1, 2006, IMPA began taking firm power and energy from I&M under a "Cost-Based Formula Rate Agreement for Base Load Electric Service." Initially, this agreement provided IMPA with base load power and energy for a twenty-year period. The initial contract quantity under this agreement was 150 MW. IMPA may increase its purchases by up to 10 MW each year to a maximum delivery of 300 MW. The current contract quantity is 190 MW. I&M's demand and energy charges are calculated each year according to a formula that reflects the previous year's costs with an annual "true-up". I&M is responsible for providing the capacity losses and reserves under this contract. The contract was extended in 2010 and now has an expiration date of May 31, 2034.

Other Power Purchases

In January 2019, IMPA entered into a contract with Alta Farms II, LLC for the purchase of up to 75 MW of wind energy from the Alta Farms II Wind Farm located in DeWitt County, Illinois. This project was declared operational in May of 2023.

In January 2020, IMPA entered a contract with Ratts I Solar Farm, LLC for the purchase of 100 MW of solar energy from the Ratts I Solar Farm located in Pike County, Indiana. This contract was subsequently amended to increase the offtake amount to 150MW. Deliveries are scheduled to begin by 2025.

At the time of writing, IMPA was also negotiating a 200 MW power purchase agreement with Cold Spring Solar, LLC. However, this project, as part of the MISO interconnection process, was assigned transmission upgrade costs that may make the project economically unviable.

IMPA has entered various monthly purchased power contracts with multiple counterparties to supplement the power and energy available to it from other resources. IMPA engages in both physical and financial transactions for capacity and energy. IMPA currently has market capacity and energy purchases extending to 2026.

Green Power

IMPA offers a Green Power rate to its members, for pass through to their retail customers. Under this rate, IMPA will obtain and provide green power for a small incremental charge over its base rate. As discussed above, IMPA currently has access to over 200 MW of solar facilities, and 75 MW of wind facilities IMPA members implement the Green Power rate if they desire. Currently, IMPA members have 67 retail customers on the Green Power rate and sell just under 25,000 MWh per year under the program.

Net Metering/Retail Customer-Owned Generation (Renewable)

On January 28, 2009 the Board approved IMPA's net metering tariff. This tariff allowed for the net metering of small renewable energy systems at retail customer locations. As with the Green Power rate, the net metering tariff was implemented at each member's discretion. Currently, there are approximately 80 traditional net metering installations in members' service territories with a total installed capacity of approximately 530 kW.

After the passage of Senate Enrolled Act 309 (2017) in which Indiana's net metering laws were changed by the Indiana General Assembly, IMPA changed its policy to an excess customer generation policy. Though IMPA is not bound by this state law, IMPA management believes following the spirit of the state laws avoids confusion to retail customers. Under this program, retail customers may install any renewable systems they wish. Like the state law, any power generated in excess of instantaneous needs of the customer is purchased by IMPA at a rate determined by the agency on an annual basis. Under the program, the retail customer must sign an interconnection and safety agreement with the local utility and a purchased power agreement with IMPA. As of the date of this report, IMPA, has contracted with 117 customers, totaling 3.6 MW of installed renewable energy systems.

Retail Customer-Owned Generation (Non-Renewable)

IMPA does not currently have any customers on the system that operate a combined heat and power (CHP) system. While under the right circumstances CHP systems could be beneficial to both the customer and IMPA, the right mix of site-specific operating conditions and economics must be in place for both parties for a CHP project to go forward.

Except for emergency back-up generators at some hospitals, factories, commercial customers, and water treatment plants, IMPA knows of no other non-renewable retail customer generation in its members' service territories.

5.4 EXISTING DEMAND-SIDE RESOURCES

Existing demand-side resources consist of programs coordinated by IMPA as well as those implemented by its members. A discussion of existing programs is provided below.

IMPA Energy Efficiency Program History

In early 2011, IMPA launched the IMPA Energy Efficiency Program, designed to help retail customers in the Agency's member communities save money through incentives for implementing energy-saving measures in four different categories: energy efficient lighting, heating, ventilation, and air conditioning (HVAC); motors, fans & drives; and refrigeration, food service and controls. IMPA worked with member utilities to market the program, educate customers, and build relationships with local vendors to implement the energy saving measures.

In 2012 and 2013, IMPA voluntarily participated in Energizing Indiana, a state-wide energy efficiency program in order to gain experience and evaluate the cost-effectiveness of a variety of residential, commercial, and industrial programs. The savings from these efficiency efforts was 32 million kWh (2012) and 52.7 million kWh (2013), annually.

In 2014, IMPA returned to the more cost-effective, self-managed energy efficiency program, which it first launched in 2011.

Figure 6 IMPA Energy Efficiency Programs

Source: www.impa.com/energyefficiency

Energy Efficiency and Conservation Education

IMPA has long promoted energy efficiency and conservation in its member communities. IMPA includes such information, developed both from public and internal sources, in the Municipal Power News, which is a publication which IMPA mails to members' customers' homes and businesses three times each year, as well as through multiple social media platforms. The Agency also provides literature containing conservation and efficiency tips to member communities for distribution in their local utility offices or events.

IMPA's website at www.impa.com/energyefficiency includes energy efficiency, conservation, and safety information for consumers as well as links to various energy calculators and USDOE information.

Demand Response

On December 10, 2010, IMPA's board approved Demand Response tariffs to utilize demand response programs offered under the MISO and PJM tariffs. At this time, no customers are participating in the program. As part of IMPA's preferred plan, IMPA will be enlisting the help of a Demand Response Aggregator to assist in examining market potential and enrollment of eligible customers to a revised demand response tariff.

Member Programs

IMPA's members have implemented a variety of programs and projects tailored to their individual systems to reduce peak demand and encourage efficient energy use. Most of these programs are rate or customer service related. Examples include coincident peak rates, off-peak rates, power factor improvement assistance, load signals to customer-owned peak reduction or energy management systems, advanced meter infrastructure/automatic meter reading, and streetlight replacement with more efficient lamps.

Summary

Through the end of 2023, IMPA's energy efficiency programs have generated a cumulative savings of 121,000 MWh and a coincident peak reduction of approximately 13.6 MW.

5.5 IMPA Transmission

A large portion of IMPA's load is connected to the Joint Transmission System (JTS) that is jointly owned by DEI, IMPA, and WVPA. Pursuant to the terms of the "Transmission and Local Facilities Ownership, Operation, and Maintenance Agreement" (the T&LF Agreement) and the "License Agreement," IMPA dedicated and licensed the use of its portion of the JTS to itself, DEI, and WVPA. DEI and WVPA similarly dedicated and licensed the use of their facilities to IMPA. The T&LF Agreement provides mechanisms for the owners to maintain proportionate ownership shares and to share proportionately in the operating costs and revenues from the JTS.

IMPA owns but does not operate transmission facilities. DEI is responsible for the operation and maintenance of the JTS. In addition, DEI performs all load and power flow studies for the JTS and recommends improvements or expansions to the JTS Planning Committee for its approval. DEI files the FERC Form 715 on behalf of the entire JTS.

IMPA is a member of MISO as a Transmission Owner (TO). DEI and WVPA are also TO members of MISO. The higher voltage facilities of the JTS are under the operational and planning jurisdiction of MISO.

Approximately two thirds of IMPA's load is connected to delivery points on MISO-controlled transmission lines of the JTS, Northern Indiana Public Service Company (NIPSCO) and Centerpoint/Vectren. The remaining portion of the members' load is connected to delivery points on the AEP and Duke-OH transmission systems, located in the PJM footprint. IMPA is a transmission dependent utility (TDU) for all load not connected to the JTS system, approximately 50%. For these loads, IMPA purchases Network Integration Transmission Service (NITS) under the appropriate zonal tariff.

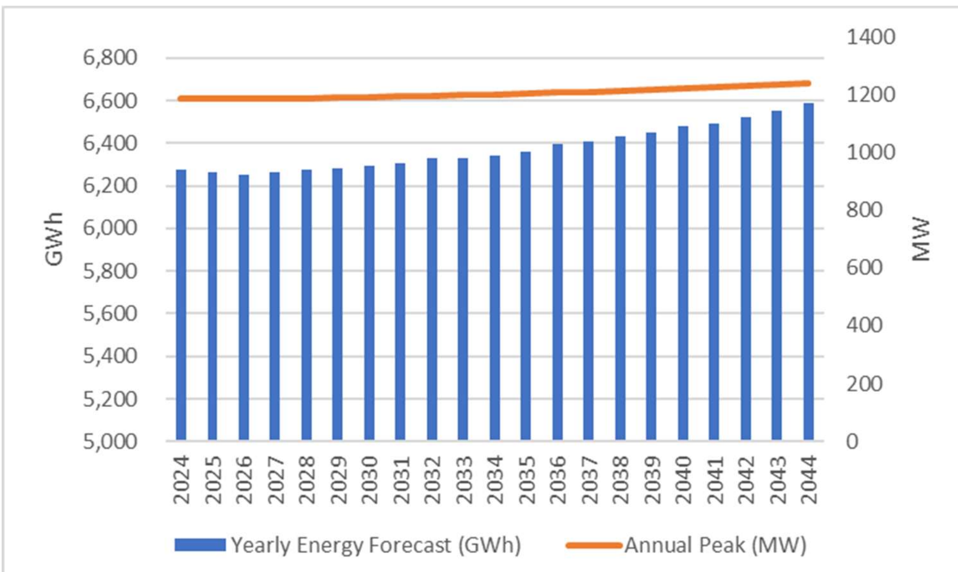
6 LOAD FORECAST

As a basis for this IRP, IMPA developed a 20-year projection of peak demands and annual energy requirements by month. This section describes the methods employed, their results, historical performance, and alternative methods of forecasting.

6.1 LOAD FORECAST OVERVIEW

IMPA independently forecasts each of its 5 load zones using a linear regression model developed using historical load and weather data. IMPA then uses normalized weather and forecasted economic data as independent variables to create a forecast with monthly energy and peak demand values.

Figure 7 IMPA Load Forecast



The above figure represents forecasted annual energy and yearly system peak values. IMPA expects an average energy growth rate over the forecasted period of .21%. Growth in peak demand is expected to be similarly flat at an average rate of .20%, with modest amounts of load growth coming from EV penetration.

6.2 ENERGY FORECAST METHODOLOGY

The forecasts used as a basis for scenario planning in this IRP start with regression models. These regression equations are then used to predict energy consumption and peak utilization levels on a monthly basis. The independent variables used to create these regression equations differ slightly across load zones, as a single model does not account for enough of the geographic and demographic differences across zones. In general, the models rely on one or more macroeconomic variables (e.g. Real GDP Growth Rate or Unemployment Rate) to capture changes in energy consumption related to economic activity and a variety of weather-related variables to capture changes in energy consumption related to temperature. IMPA annually evaluates its load forecasts to search for new variables that might better describe the relationships between weather, economy, people, and demand. An obvious area for improvement is the use of national data to describe a localized environment; many of the communities that IMPA serves experience an economic environment very different than the environment painted by national data. Unfortunately, data that is localized, current, accurate, and forecastable has proven very difficult to find. Tables 4 and 5 summarize the regression statistics and variables used in the load forecast process.

Table 4 Energy Forecast Regression Statistics and P-Values

Area	HDD	CDD	Peak Days	Off-Peak Days	U2
AEP (I&M)	5.01E-65	9.09E-55	8.16E-19	1.25E-12	0.008284
DUK-IN	4.50E-66	9.06E-71	5.30E-24	3.92E-18	4.00E-13
DUK-OH	2.01E-18	1.03E-18	2.31E-02	2.37E-01	4.29E-10
NIPSCO	4.64E-12	8.32E-27	2.47E-14	1.10E-05	3.85E-04
Centerpoint (Vectren)	2.77E-28	6.29E-53	1.20E-15	2.21E-06	N/A

Area	Peak Season Dummy	Jasper Dummy	Annual GDP Change	Model Adj. R^2	Observations
AEP (I&M)	0.001232	N/A	N/A	0.9	211
DUK-IN	1.33E-05	N/A	4.04E-01	0.94	211
DUK-OH	2.99E-01	N/A	N/A	0.66	187
NIPSCO	1.20E-02	N/A	1.54E-02	0.82	211
Centerpoint (Vectren)	3.65E-01	7.86E-28	4.30E-01	0.93	211

Table 5 Description of Energy Forecast Regression Variables

Variable	Description
HDD	The sum of all heating degree days during the month
CDD	The sum of all cooling degree days during the month
Peak Days	Number of non-holiday, non-weekend days during the month
Off-Peak Days	Number of weekend days, plus the number of holiday-days
U2	National Unemployment Rate
Peak Season Dummy	Binary dummy variable set to either 1 for summer, or 0 for all other seasons*
Jasper Dummy	A binary Variable to account for unexplained loss of demand in the Vectren load zone
Annual GDP Change	% change in GDP from previous year

IMPA sources weather data from Energy Velocity[3], using different weather stations in each load zone. IMPA uses historical data to create the regression model and then relies on a normalized

[3] https://www.velocitysuiteonline.com/RDWeb/Pages/en-US/login.aspx?ReturnUrl=/RDWeb/Pages/en-US/Default.aspx

weather year for forecasting purposes. Historical economic data is gathered from FRED[4], and forecasted economic data is gathered from the Survey of Professional Forecasters[5].

6.3 Energy Forecast Electric Vehicle Addendum

In an effort to capture vehicle electrification as a vector for sales growth, IMPA has implemented an ex-post forecast adjustment based largely on impending growth in the electric vehicle market. In many places, EV based load growth represents a significant hill to climb in an already tight market, with clogged interconnection queues and slimming reserve margins. IMPA has conducted its own analysis on vehicle electrification to better distil the impacts such a trend would have on its members.

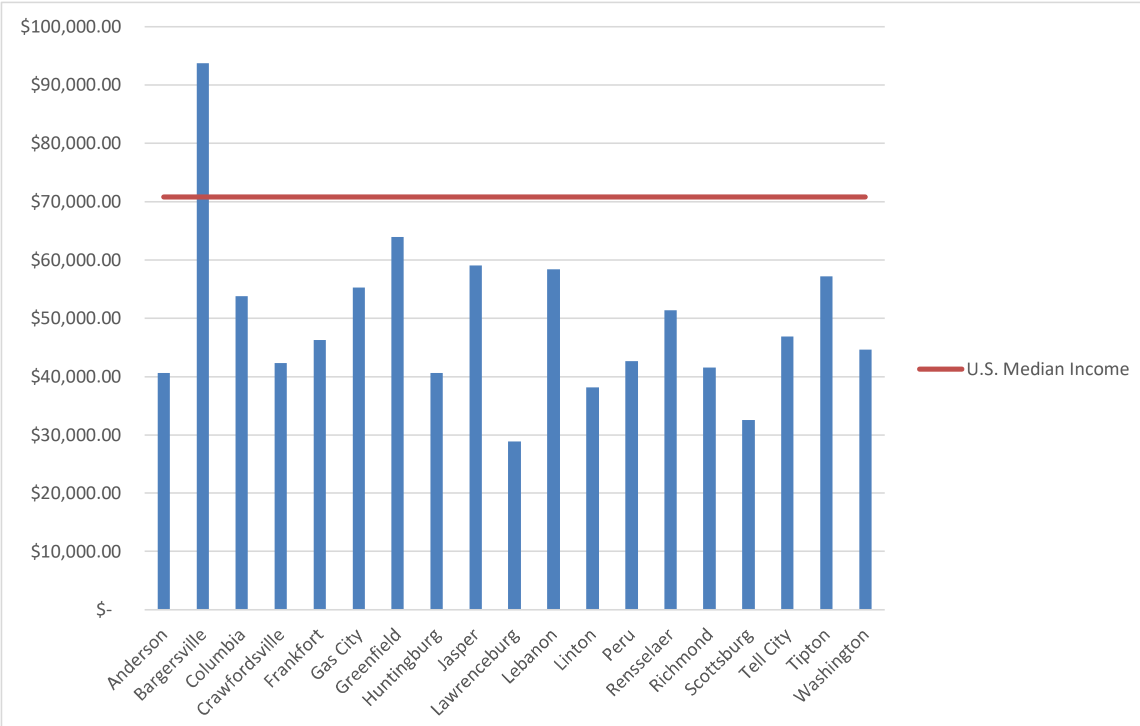
IMPA's analysis started with an independent national electric vehicle sales forecast provided by Wood-Mackenzie[6]. This forecast, along with publicly available data regarding vehicle registrations, was used to create an electric vehicle population forecast at the national level. From this point forward, IMPA developed a load-impact forecast based on a few simplifying assumptions:

1. IMPA's member population will initially adopt electric vehicles at a slower rate than the national rate.

IMPA's member communities tend to earn a lower household income compared to the rest of the nation. Out of the member communities whose population is more than 5,000 people, only one of IMPA's communities had a higher median household income than the national level. It stands to reason that a population that has less money to spend will hold onto existing cars for longer or substitute away from what are generally more expensive vehicles. IMPA's electric vehicle forecast slowly increases the rate of member EV adoption until it is in line with the national level in 2030, coinciding with the Biden administration goal of 50% of new car sales being electric vehicles. Figure 8, on the following page, illustrates sample household median income from IMPA member communities compared to median national household income.

[4] https://fred.stlouisfed.org/
[5] https://www.philadelphiafed.org/surveys-and-data/real-time-data-research/survey-of-professional-forecasters
[6] https://www.woodmac.com/our-expertise1/capabilities/electric-vehicles/

Figure 8 Median Household Income



2. Most electric vehicle charging occurs outside of on-peak hours.

According to a study by the Idaho National Laboratory, more than 80% of electric vehicle owners charge at home and most of these owners charge overnight.[7] IMPA believes that this trend will hold inside its member communities as the people in them commute to and from their job and thus charge when they get home.

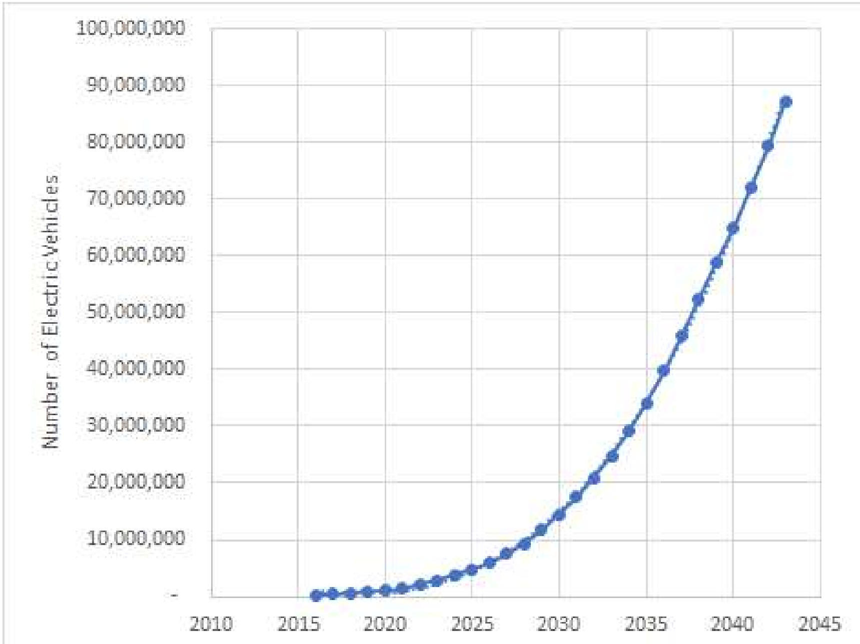
3. IMPA's member population allocate 100% of their charging hours to charging stations or homes located within the IMPA footprint.

This assumption has been made for ease of modelling, and it provides a more generous floor for estimating impacts to load. The electric vehicle sales forecast undergoes three transformations based on these assumptions. The first transformation is from a national sales forecast to a national EV *population* forecast. Using data from the Alternative Fuels Data Center[8] and assuming a 10%

[7] https://avt.inl.gov/sites/default/files/pdf/arra/PluggedInSummaryReport.pdf
[8] https://afdc.energy.gov/vehicle-registration

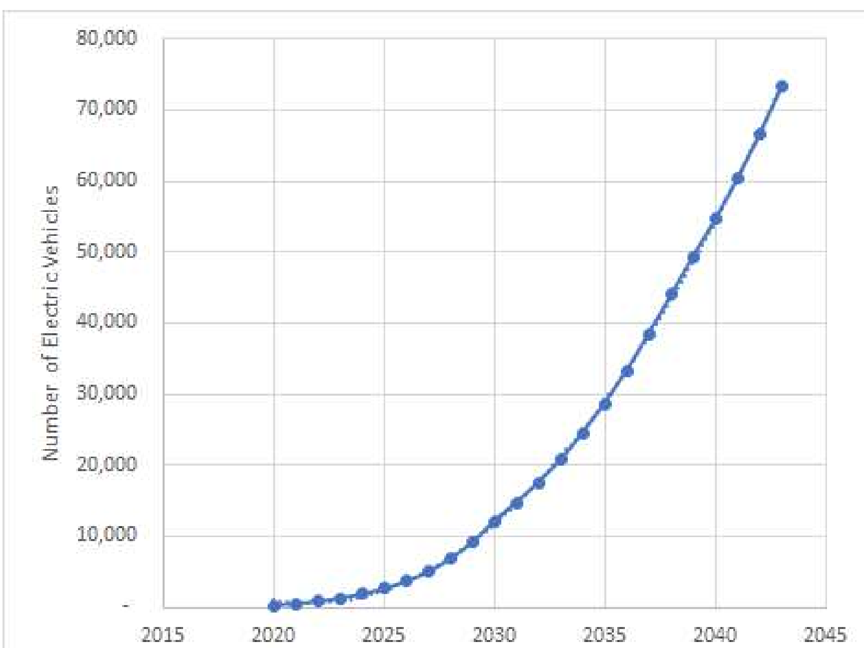
retirement rate after 10 years an estimate for the total number of U.S. electric vehicle registrations can be created.

Figure 9 Projected U.S. Consumer Electric Vehicles



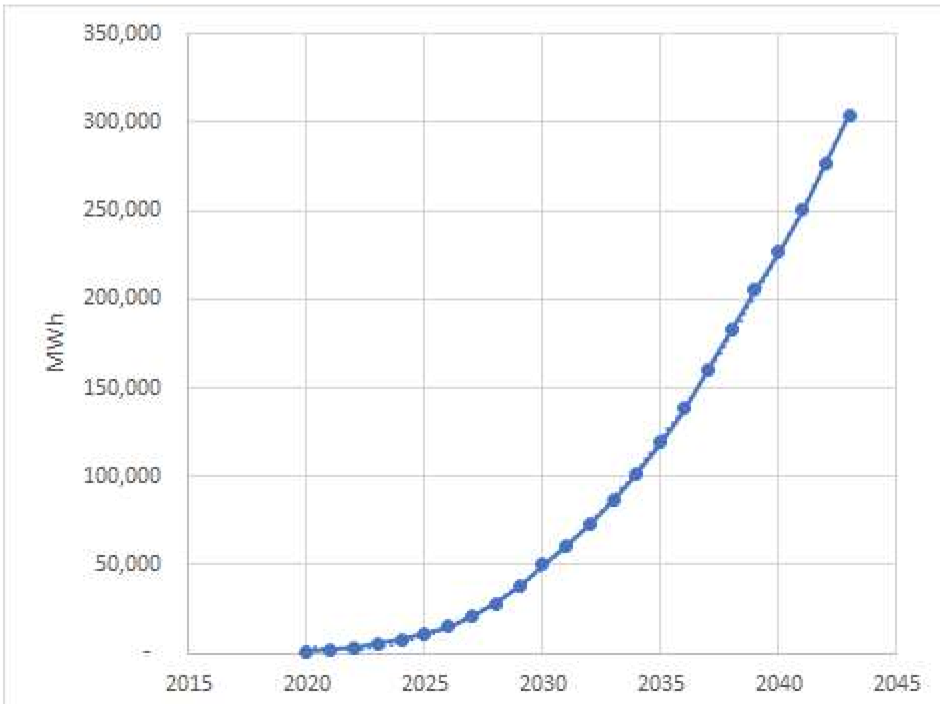
The second transformation is from a national forecast to a more localized forecast. The national data is multiplied by a series of ratios to capture the differences between nation-wide trends and IMPA demographics.

Figure 10 Projected IMPA Member Electric Vehicles



The third and final transformation the forecast must undergo is from a forecast of Electric Vehicles to a forecast of additional energy usage. A conservative estimate of 34.6 kWh per 100 miles driven, and an average mileage per year of 12,000 per vehicle yields a value of additional megawatt hours demanded that wouldn't be captured by the regression model.

Figure 11 Additional Annual MWh from Electric Vehicles



These annual values are then split into monthly values and allocated to the RTOs to be added onto the RTO forecasts. The base case assumes that member electric vehicle adoption rates match the national rate by 2030, and other cases move the "match year" forward or backwards as needed.

6.4 Peak Demand Forecast Methodology

As with the IMPA energy forecast, the demand forecast is based on a linear regression model. The model predicts the peak load in each load area on a monthly basis. The independent variables used to create these regression equations differ slightly across load zones as a single model does not account for enough of the geographic and demographic differences across zones.

In general, IMPA links its demand and energy regressions with a macroeconomic variable (in this case National Unemployment rate) in order to provide cohesive and complementary forecasts. IMPA utilizes modified weather variables in its demand forecasts in comparison to its energy forecasts; degree day values are replaced with degree day *equivalents* that impute factors such as humidity and wind chill to better capture the way people *feel* temperature, which is a slightly better predictor than simply the temperature related values themselves. IMPA's summer peak load is fairly air-conditioner sensitive, so an additional 3-day moving average variable is included alongside the cooling degree-day equivalent value, which helps to capture the effects of multi-day heat waves on consumer psychology as it pertains to air conditioning usage. Table 6 and 7 summarizes the regression statistics for the peak demand forecast.

Table 6 Demand P-values and Regression Statistics

Area	National Unemployment	HDD Equivalent	CDD Equivalent	CDD 3 day MA
AEP (I&M)	5.55E-01	1.09E-50	4.21E-11	1.15E-05
DUK-IN	3.72E-03	3.47E-51	1.30E-14	5.94E-06
DUK-OH	1.45E-03	8.53E-21	N/A	1.43E-17
NIPSCO	4.63E-05	1.07E-05	1.71E-03	5.37E-08
Centerpoint (Vectren)	2.30E-01	1.13E-50	3.97E-10	7.85E-13

Area	Peak Season Dummy	Jasper Dummy	Model R^2	Observations
AEP (I&M)	N/A	N/A	0.86	211
DUK-IN	N/A	N/A	0.89	211
DUK-OH	N/A	N/A	0.72	79
NIPSCO	1.13E-17	N/A	0.85	211
Centerpoint (Vectren)	N/A	1.40E-23	0.93	211

Table 7 Description of Demand Independent Variables

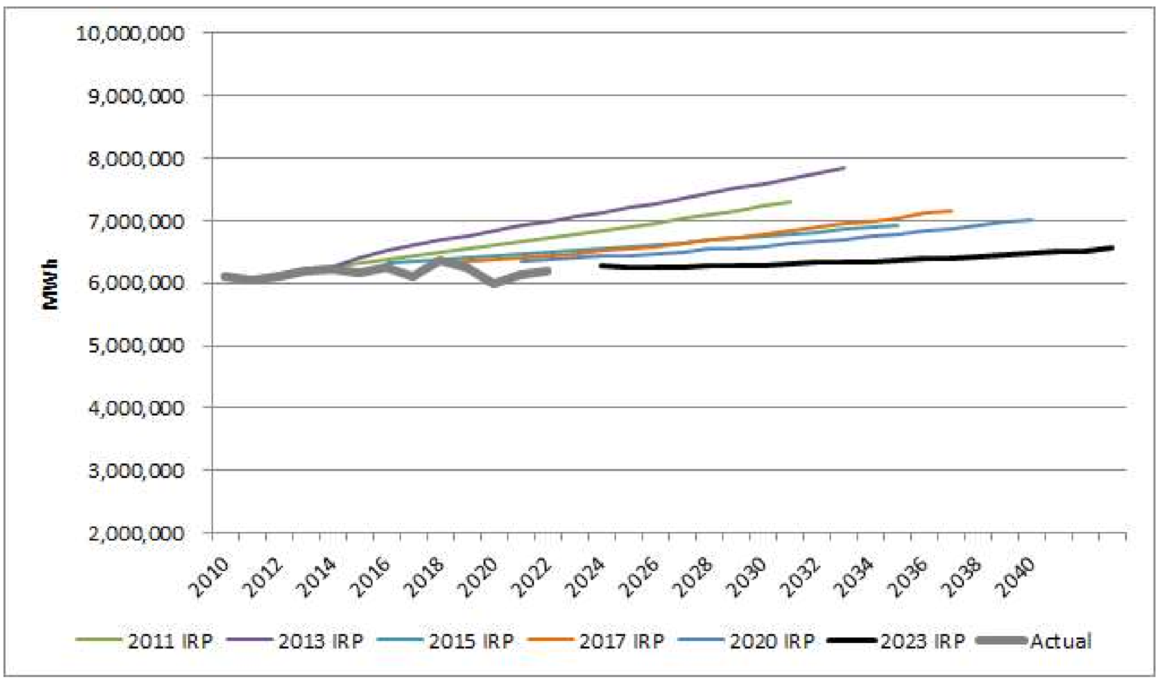
Description of Independent Variables	
Variable	Description
National Unemployment	National Unemployment Rate
HDD Equivalent	Heating Degree Days adjusted to account for a "real-feel"
CDD Equivalent	Cooling Degree Days adjusted to account for a "real-feel"
CDD 3 day MA	The three day moving average of the number of adjusted cooling degree days
Peak Season Dummy	A trinary dummy variable set to either 0, 1, or 2 depending on the season and model
Jasper Dummy	A binary Variable to account for unexplained loss of demand in the Vectren load zone

IMPA sources weather data from Energy Velocity[9] using different weather stations in each load zone. IMPA uses historical data to create the regression model and then relies on a normalized weather year for forecasting purposes. Historical economic data is gathered from FRED[10] and forecasted economic data is gathered from the Survey of Professional Forecasters[11].

6.5 COMPARISONS TO PAST FORECASTS

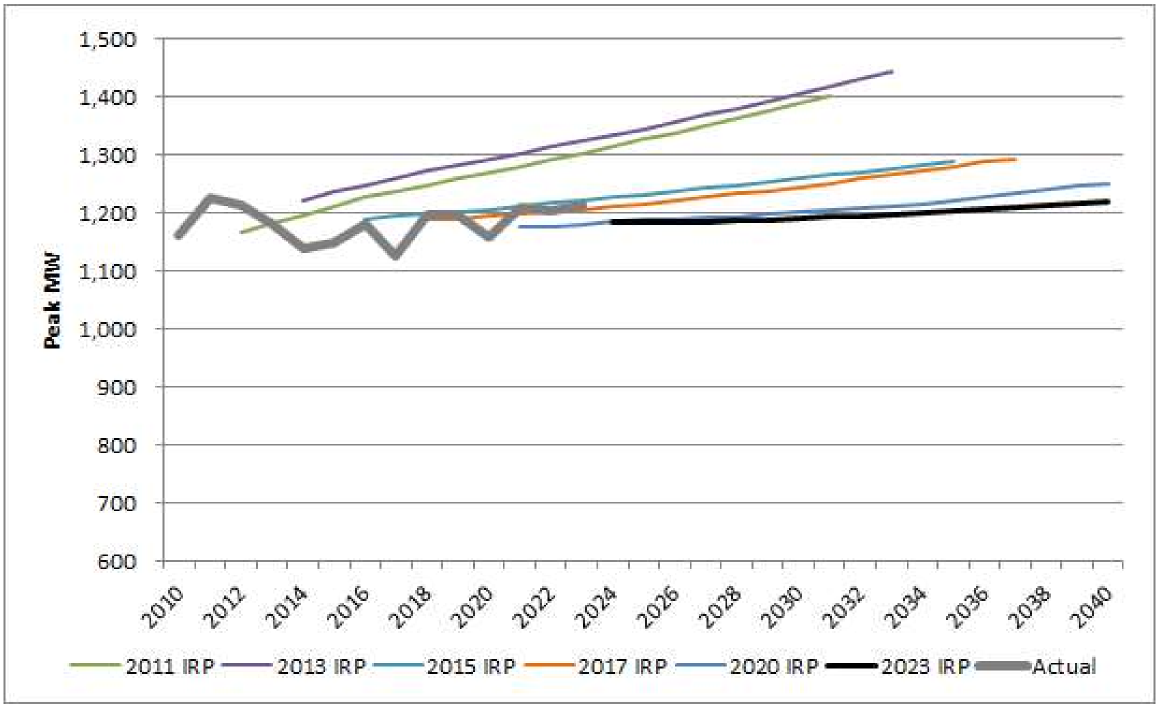
The following figures compare IMPA's load forecasts to the forecasts used in each of the prior five IRPs as well as the actuals through 2022.

Figure 12 Historical Energy Forecast Comparison



[9] https://www.velocitysuiteonline.com/RDWeb/Pages/en-US/login.aspx?ReturnUrl=/RDWeb/Pages/en-US/Default.aspx
[10] https://fred.stlouisfed.org/
[11] https://www.philadelphiafed.org/surveys-and-data/real-time-data-research/survey-of-professional-forecasters

Figure 13 Historical Peak Forecast Comparison



6.6 What-if Forecasts

As a part of the integrated resource planning process, IMPA creates alternative load forecasts depicting possible futures that differ from the underlying forecasted economic data used in the main load forecast. These alternate forecasts show a "*what if*" version of the future, where economic outcomes may be more or less optimistic. These alternatives are created using the same models but inputting lower growth rates and higher unemployment rates. Alternate energy forecasts are also characterized by higher or lower levels of future electric vehicle penetration. The "Base Case" describes the most likely future, informed by a combination of in-house forecasting, weather normalization, and macroeconomic forecasts from the Survey of Professional Forecasters. The "Voluntary Net-Zero" case utilizes a more optimistic forecast driven by an assumed high GDP growth rate, a low unemployment rate, and a faster rate of electric vehicle adoption by IMPA's member communities. The "Austerity Case" utilizes a forecast that assumes much of the opposite: low GDP growth, low electric vehicle adoption, and high unemployment.

Table 8 Case Energy Forecast Comparison (GWh)

Year	Base Case	Voluntary Net Zero Case	Austerity Case
2024	6,274	6,299	6,138
2025	6,261	6,296	6,089
2026	6,255	6,295	6,096
2027	6,263	6,310	6,140
2028	6,278	6,328	6,139
2029	6,280	6,328	6,153
2030	6,293	6,337	6,145
2031	6,303	6,352	6,114
2032	6,332	6,387	6,192
2033	6,329	6,381	6,142
2034	6,342	6,400	6,177
2035	6,362	6,429	6,219
2036	6,395	6,461	6,203
2037	6,406	6,479	6,231
2038	6,430	6,509	6,219
2039	6,452	6,537	6,271
2040	6,482	6,569	6,265
2041	6,495	6,592	6,297
2042	6,521	6,624	6,324
2043	6,552	6,664	6,327

Table 9 Case Forecast Comparison (Peaks)

Year	Base Case	Voluntary Net Zero Case	Austerity Case
2024	1,186	1,189	1,161
2025	1,186	1,190	1,155
2026	1,185	1,193	1,156
2027	1,186	1,193	1,162
2028	1,187	1,195	1,159
2029	1,189	1,197	1,162
2030	1,191	1,200	1,158
2031	1,193	1,203	1,151
2032	1,195	1,205	1,160
2033	1,198	1,206	1,152
2034	1,200	1,209	1,155
2035	1,203	1,212	1,159
2036	1,206	1,217	1,151
2037	1,210	1,225	1,154
2038	1,214	1,229	1,148
2039	1,218	1,231	1,153
2040	1,222	1,239	1,147
2041	1,226	1,241	1,151
2042	1,230	1,246	1,151
2043	1,235	1,255	1,146

Figure 14 IMPA total MWhs Comparison

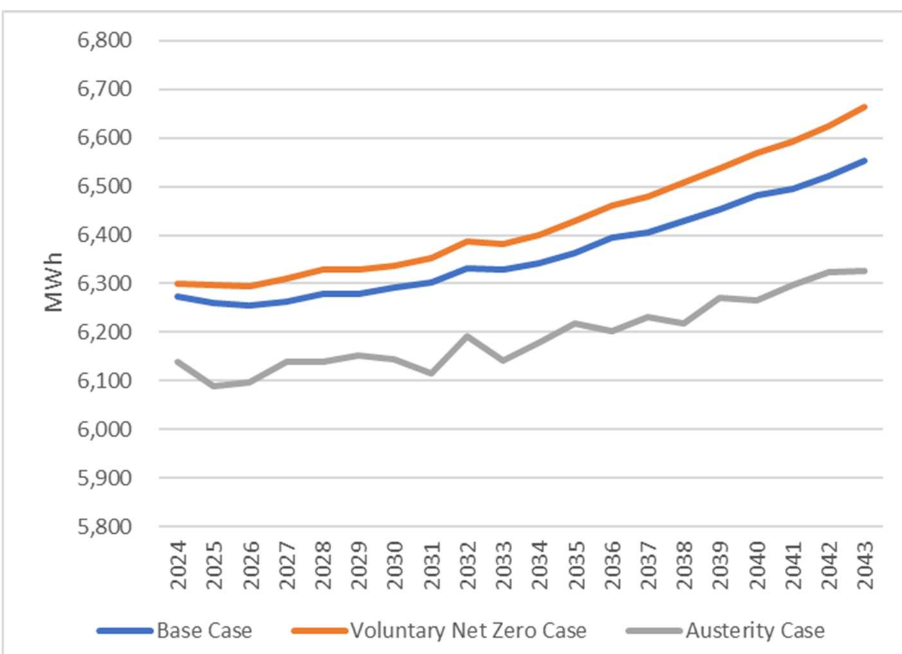
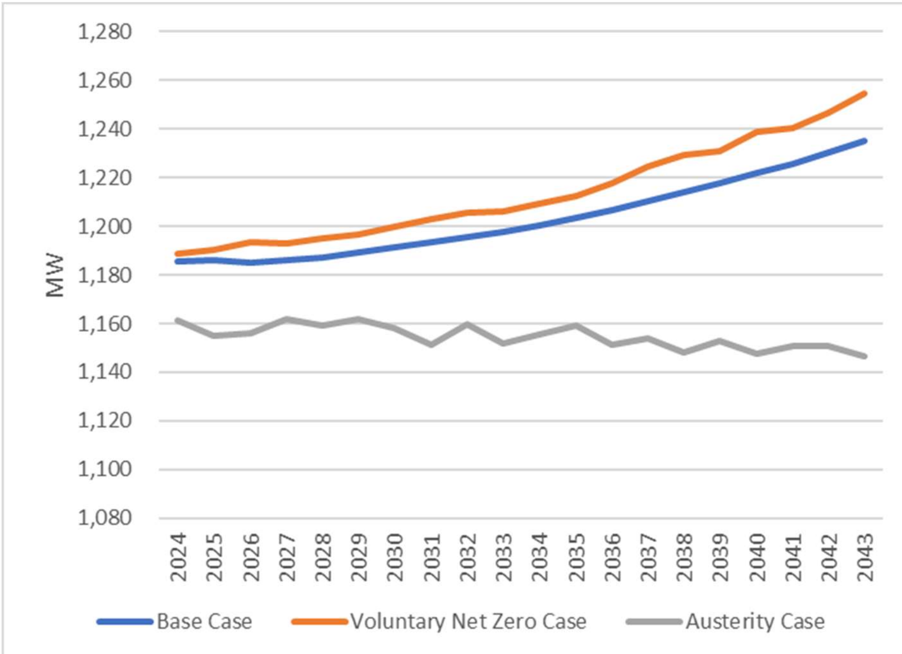


Figure 15 IMPA System Peak Comparison



6.7 ALTERNATE LOAD FORECAST METHODOLOGIES

Rate Classification/Sector Methodology

IMPA has not generated forecasts by rate classification or sector. Since IMPA does not sell directly to retail customers, it does not have direct access to customer billing units. To generate a customer sector forecast, IMPA would need to collect several years of annual historical billing summary data from each of its 61 members. In addition, the criteria determining member rate classes can change over time and it would be nearly impossible to ensure consistent sector data back through the historical period. Finally, different members identify sectors (or classes) of customers differently.

End-Use Methodology

Another forecast methodology is end-use. The data requirements for an end-use model are extensive. They include detailed information on appliance saturations and usage patterns in the residential sector, data on building and business types in the commercial sector, detailed equipment inventories, lighting types, and square footage area in the industrial sector. IMPA's member communities are not uniform, they contain various ages of homes and businesses. The age of the residents and vintage of the houses can have a significant impact on the saturation of various appliances. To collect the proper saturation data at the member level, IMPA would need to collect a valid sample of each member's customers. Given that IMPA would need to sample a substantial portion of its members' retail consumers to achieve a statistically valid sample, end use sampling is unreasonable for IMPA to implement. Therefore, IMPA cannot realistically utilize this type of a forecast model.

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7 RESOURCE OPTIONS & ALL SOURCE RFP

7.1 SUPPLY-SIDE OPTIONS

Potential supply-side options include upgrades to existing generating capacity, construction or acquisition of additional generating capacity, and entering into additional contracts for purchased power. New IMPA-owned capacity could include generating units constructed and owned by IMPA or participation in the ownership of either existing or new generating units with third parties. Purchased power could include purchases from other utilities, independent power producers or power marketers. While IMPA is well situated to construct, own, and operate smaller generating facilities such as peaking plants, solar plants, and landfill gas plants. As a practical matter, IMPA would expect to participate with others in the development of any new large generation resources. Joint development of resources would enable IMPA to enjoy the economies of scale of a larger facility and at the same time adhere to the principle of diversification.

This year's IRP modeling was broken into several components. First, IMPA extensively modeled power supply options and scenarios throughout 2022. As EIA information for 2023 became available, these were effectively refreshed in early 2023. Finally, as best fit resources were confirmed on a hypothetical basis using the new EIA data, IMPA issued an All Source RFP in order to see what real world options were available to pursue.

Additional Upgrades or Retirements of Existing Capacity

IMPA's existing generating capacity consists of its ownership interests in Gibson 5, Trimble County 1 and 2, Prairie State 1 and 2, seven wholly owned combustion turbines as, well as Whitewater Valley Station. IMPA is not aware of any potential upgrades to any of the facilities that could increase their output capability.

As this report was being finalized, the joint owners of Gibson 5 opted to extend the unit's life until May 31st, 2030. For the purposes of this IRP, Gibson was allowed to retire economically in all model runs, however, leading to varying retirement dates across scenarios.

In addition, the proposed rulemaking from the EPA regarding Effluent Limitations sees Whitewater Valley Station removed from the portfolio effective December 31st, 2028. However, plans for Whitewater Valley Station's actual operations could change depending on the EPA's final rule.

All other IMPA-owned units were given the opportunity to retire in the capacity expansion runs.

If an IMPA unit is retired, all future capital expenditures and operating costs are removed, however, any bond obligations associated with the facility remain. When a unit is retired it is assumed the decommissioning expense is equal to the salvage value.

New Resources

The purpose of an IRP is to assist the company in determining its future generation requirements at a basic needs level, not to select the specific unit and model. The selection of the actual brand and model to construct would be determined in the bid and project development process.
The traditional, thermal generating resources considered in this study include:

- Advanced combined cycle units
- Advanced gas-fired combustion turbines
- Aero-derivative combustion turbine
- High efficiency internal combustion units
- Small Modular Nuclear Reactors (SMRs)

Capital cost, fixed and variable cost, and operating assumptions were sourced from "Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2023" from the U.S. Energy Information Administration. Additional information gleaned from IMPA's solar program and renewable RFPs issued by IMPA was used to fine tune the estimates.

During IMPA's consideration of supply-side resources, it assumes any new resource would comply with the applicable environmental requirements. Such requirements specify that the potential resource undergoes an environmental review prior to the beginning of construction and that the potential resource complies with any environmental constraints. If IMPA petitions the IURC for approval relating to new supply-side resource, IMPA would include information concerning these environmental matters, including the results of any due diligence investigations.

Power and Bi-Lateral Capacity Purchases

IMPA's capacity position is such that near-term shortfalls are not commercially feasible to fill with a physical asset. Longer term, IMPA is cautious about the potential for rule changes and price shocks to capacity markets. While IMPA allowed financial power purchases to be made by the model, capacity products were limited to physical assets only. IMPA's financial model balances the capacity positions on an annual basis.

Energy Markets

IMPA participates in both the MISO and PJM markets for balancing capacity and short-term energy purchases/sales. While market products were included in the model for near term requirements, IMPA does not believe it is prudent to rely solely on these RTO capacity and energy markets to meet its long-term capacity and energy requirements. However, reserve margin flexibility is allowed in order to allow for load uncertainty, energy efficiency, renewable development and customer owned generation.

For the purposes of this IRP, IMPA limits the installation of new resources to those needed to serve its own load. Although IMPA will sell short–term surplus capacity and energy through the organized markets, IMPA will not install generation for the purpose of speculative sales.

7.2 RENEWABLE OPTIONS

In addition to the traditional resources discussed above, the expansion model was allowed to select renewable resources as well. The renewable alternatives included in the expansion analysis are shown below.

- Utility Scale Wind
- Utility Scale Photovoltaic Solar
- Utility Scale Battery Storage

Pricing for all the renewable alternatives was based on the EIA data, IMPA's experience in constructing facilities, indicative market quotes from renewable energy providers, and industry documentation of installed and operating costs.

See Appendix E for detailed expansion unit data.

As stated elsewhere, IMPA has been developing solar parks for its member communities since 2014 and now has 50 parks totaling 194.7 MW. At this time, an additional four parks totaling 13.1 MW are under development or under construction. IMPA will continue to evaluate the commissioning of any future parks based on member community demand and IMPA's own portfolio needs.

7.3 Demand-Side Options

IMPA's goal is to provide low cost, reliable, and environmentally responsible electric power to its members. IMPA accomplishes this by maintaining a diverse set of energy resource options along with its existing energy efficiency program.

Since the Energizing Indiana program ended in 2013, the IMPA energy efficiency program has been the primary vehicle used to provide energy efficiency options to IMPA members' retail customers. The program is a prescriptive rebate system providing incentives for the installation of dozens of items. Incentives are available for both residential and C&I customers.

Residential Incentive Measure Groups

- Central Air Conditioner >16 SEER
- Air to Air Heat Pump >16 SEER
- Geothermal Heat Pump
    - Open Loop >17.1 SEER
    - Closed Loop >21.1 SEER

Commercial and Industrial Incentive Measure Groups

- Variable Frequency Drive Pumps and Motors
- Heating Ventilation and Air Conditioning
- Refrigeration, Food Service and Controls

Both measures and incentive amounts are reviewed periodically to determine additions, deletions, or modifications to incentive payments.

A description of programs and listing of all eligible items and incentives can be viewed at:

https://www.impa.com/energyefficiency

Going forward, the IMPA energy efficiency program will continue to be IMPA's primary method of offering energy efficiency services to member communities.

Finally, as part of the planning process, IMPA has been engaging with Demand Response aggregators to expand potential savings for members in a manner that is mutually beneficial to all parties involved.

Energy efficiency and demand response were modeled as selectable resources in the model.

7.4 ALL-SOURCE RFP ISSUANCE

As part of this year's IRP process, IMPA issued an All-Source RFP for projected capacity needs stemming from the retirement of Gibson 5. For its 2023 IRP, IMPA began by modeling resources at their EIA estimated costs to find the most optimal, if theoretical, portfolio possible. Once this portfolio was determined, the All-Source RFP was issued to a wide array of market participants requesting the resources the initial optimization suggested. Responses deemed suitable to IMPA's portfolio needs were then utilized in the Encompass model as selectable resources. This process was then utilized to optimize the portfolio around near and intermediate actionable choices, and more long term, potentially theoretical choices. The results are discussed in more detail in Section 12.7.

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8 ENVIRONMENTAL

8.1 COMPLIANCE WITH CURRENT RULES

The following sections describe compliance actions IMPA expects to be taken at its generating facilities in connection with environmental rules.

General

The Mercury and Air Toxics Standards

The EPA issued in March 2011 the final Mercury and Air Toxics Standards (MATS) rule, which is intended to set emission limits for hazardous air pollutants (HAPS), including mercury, particulate matter, and hydrochloric acid for coal and oil-fired generating units greater than 25 MW. On December 27, 2018, the EPA issued proposed revisions to the Supplemental Cost Finding for MATS. In this proposed rule, the EPA has determined that it is not "appropriate and necessary" to regulate HAP emissions from power plants under Section 112 of the Clean Air Act. It will, however, maintain existing standards and regulations relating to coal- and oil-fired electric generating units (EGUs). On May 20, 2020, EPA found that it is not appropriate and necessary to regulate coal- and oil-fired EGUs under Clean Air Act (CAA) section 112.

In February 2022, EPA proposed to revoke its May 2020 finding, and initiated a notice and comment rulemaking to determine whether to reaffirm its 2016 finding that such regulations are, in fact, appropriate and necessary.

As the rule stood prior to June 29, 2015, it required capital additions to Gibson 5, Trimble County Unit 1 and WWVS. Gibson 5 upgraded its electrostatic precipitator, rebuilt its duct work, refurbished its flue gas desulfurization equipment, conducted stack liner work and added calcium bromide injection. Trimble County Unit 1 added a new pulse jet fabric filter (baghouse) and induced draft fans. WWVS added systems for hydrated lime and powdered activated carbon injection. Prairie State and Trimble County Unit 2 were constructed in compliance with the rule. IMPA does not expect there to be any material changes to the rule that would cause more capital additions than that already mentioned. This rulemaking is currently pending, and IMPA anticipates monitoring any forthcoming regulations that could impact its facilities.

Coal Combustion Residuals Rule

In October 2015, the CCR rule to regulate the disposal of coal ash as nonhazardous waste from coal-fired power plants under subtitle D of the Resource Conservation and Recovery Act (RCRA) came into effect. The rule establishes nationally applicable minimum criteria for the safe disposal of coal combustion residuals in CCR landfills, CCR surface impoundments and all lateral expansions of CCR units. It applies to new and existing facilities. Gibson generating unit and the Trimble County units have a completed landfill in use. These operations consist of dry storage in lined landfills. WWVS disposes its CCR at an offsite third-party facility. Prairie State's facilities were constructed with lined landfills for dry disposal and are not impacted by this rule.

CO_2 Emissions from Power Plants

The EPA issued a proposed rule in 2023 that would limit CO_2 emissions from existing and future power plants but has not yet issued a final rule. If the proposed rule stands and survives any legal challenges, then it will require substantial capital improvements or operational changes to IMPA's existing coal-fired units that will be operating past 2040. The proposed rule would have no effect on IMPA's existing combustion turbines.

Effluent Limitation Guidelines

In September 2015, the EPA finalized the Effluent Limitation Guidelines (ELGs), which impact steam generating units that discharge to surface waters and publicly owned treatment works. On September 13, 2017, the EPA finalized a rule postponing the compliance dates for the best available technology effluent limitations, pretreatment standards for bottom ash transport water, and flue gas desulfurization wastewater set forth in the ELGs, from November 1, 2018 to November 1, 2020. The EPA finalized the 2020 Steam Electric Reconsideration Rule (2020 ELG Rule) in August 2020, establishing new deadlines and implementing subcategories for low utilization units and units ceasing coal combustion by 2028. WWVS provided proper notice that it would continue operating in the low-utilization subcategory under the 2020 ELG Rule, but EPA issued a new proposed rule in 2023 that would eliminate the low-utilization subcategory. If the proposed rule is finalized without change, then WWVS unit 2 could be required to cease operations by the end of 2028.

Final Ozone National Ambient Air Quality Standards

In October 2015, the EPA revised its national ambient air quality standards (NAAQS) for ground-level ozone to 70 parts per million (ppm), down from the 2008 standard of 75ppm. Under this 2015 ozone NAAQS, states will be required to develop and put in place pollution control plans for counties found to be in "non-attainment" with the limit. States were asked to prepare State Implementation Plans that would help resolve "good neighbor" obligations under the Clean Air Act. On February 22, 2022, EPA rejected the State Implementation Plans (SIPs) for 26 upwind states and issued a Federal Implementation Plan (FIP) to take their place in 2023. The FIP establishes an allowance-based trading program for fossil-fuel powered plants in 25 states and imposes certain post-combustion control measures. The FIP, and EPA's rejection of various State Implementation Plans preceding the FIP (SIPs), are currently the subject of litigation.

The FIP reduces emissions budgets for EGUs starting in the 2023 ozone season compared to the CSAPR Update and imposes more stringent emissions controls as well. While post-combustion reduction systems compliant with the FIP have been installed at Prairie State, Trimble County, Gibson 5, and WWVS, the system at WWVS would require significant investment to meet the FIP's currently proposed operating standards. Further, all fossil fuel-fired EGUs would be impacted by the reduction in emissions allowances available throughout the region. If the FIP survives pending litigation, it may have a financial impact on several EGUs owned or operated by IMPA, but IMPA does not anticipate a material impact on Prairie State, Trimble County, Gibson, or IMPA's combustion turbines.

The Cross-State Air Pollution Rule and the Cross-State Air Pollution Update Rule

The Cross-State Air Pollution Rule (CSAPR) and Cross State Air Pollution Rule Update (CSAPR Update) aim to reduce emissions of SO2 and NOx from electric generating units greater than 25 MW in the eastern half of the United States and to address the summertime transport of ozone for the 2008 Ozone National Ambient Air Quality Standard (2008 NAAQS).

EPA initiated a rulemaking revising the CSAPR Update on October 15, 2020. The 2020 rulemaking found that NOx emissions in 12 states—including Indiana, Kentucky, and Illinois—significantly contributed to downwind states' nonattainment under the CSAPR Update. The final revised rule was published on March 15, 2021 and requires further NOx reductions from power plants in the relevant states (the Revised CSAPR Update). The Revised CSAPR Update is the subject of litigation and is currently pending before the D.C. Circuit Court of Appeals. IMPA does not currently anticipate that this rulemaking will materially impact its generation resources.

Waters of the United States

The final Waters of the United States (WOTUS) redefined which streams, wetlands and other bodies of water are protected by the Clean Water Act. IMPA is not aware of any effects this rule has on its units but will continue monitoring the rule for future effects.

Gibson 5

Gibson 5 currently complies with the SO_2, NO_x, particulate matter and opacity requirements of the Clean Air Act and Phase II of the Acid Rain Program. Gibson 5 also complies with CSAPR NO_x and SO_2 regulations. IMPA's share of the SO_2 and NO_x emissions allowances allocated by the EPA and the Indiana Department of Environmental Management (IDEM) will satisfy most of IMPA's requirements for such allowances.

Gibson 5 complies with the annual and seasonal requirements of the NO_x rule by operating its SCR system on an annual basis. Gibson 5 will likely need to purchase a small number of allowances for SO_2 and NO_x allowances in future compliance periods.

Gibson 5 is affected by the MATS Rule and required upgrades in April 2016 for compliance. The electrostatic precipitator was upgraded, and a calcium bromide injection system was added.

Non-hazardous solid waste from this bituminous coal fired unit consists of the following CCRs: fly ash, bottom ash, and fixated sludge from the SO_2 scrubber. The solid waste is disposed in a mono-purpose solid waste disposal facility on the site or beneficially reused in the closeout of the surface impoundments at the site. DEI also actively pursues other alternative reuses of CCRs.

Small quantities of hazardous wastes may be generated from time to time from normal plant activities and may include spent solvents from parts cleaning and paint-related wastes, etc. Gibson Station normally operates as a Small Quantity Generator (<1000 kg per month). All hazardous wastes generated at Gibson Station are properly characterized prior to disposal at appropriately permitted disposal facilities. The specific disposal facility chosen for a given waste depends on the nature of that waste.

Trimble County 1

Trimble County 1 currently complies with the SO_2, NO_x, particulate matter, and opacity requirements of the Clean Air Act.

Trimble County 1 complies with the CSAPR NO_x rules by operating with low NOx burners and the SCRs on an annual basis. IMPA expects its share of allowances to satisfy most of the NO_x emissions at Trimble County.

Compliance with the CSAPR SO_2 rule is accomplished through operation of the Trimble County 1 FGD system. IMPA expects its share of allowances to satisfy the CSAPR SO_2 emissions of Trimble County 1.

Solid waste from bituminous coal consumed in the unit consists of the following CCRs: fly ash, bottom ash, and gypsum from the SO_2 scrubber. The solid waste is disposed in activities related to legacy pond closures or beneficially reused by marketing the CCRs to third parties. LG&E was issued an operating permit for the completed landfill in April 2023. Disposal of CCRs in the landfill will begin in 2024, following completion of pond closure activities..

Trimble County 1 is affected by the MATS rule, and it uses sorbent injection and a pulse jet fabric system that was installed in late 2015 for compliance.

Any hazardous waste generated at Trimble County is analyzed to confirm the hazardous nature and then profiled with LG&E's hazardous waste contractor for disposal by either incineration or placement in a certified Class C landfill. The facility maintains manifest and disposal records for all hazardous waste shipped off site.

Trimble County 2

As with Trimble County 1, compliance with CSAPR is required. Trimble County 2 will comply in the same fashion as Trimble County 1. Its allocation of NO_x and SO_2 allowances are adequate to cover its emissions.

Trimble County 2 is subject to the MATS rule and is fully equipped for compliance.

Solid waste from bituminous and sub-bituminous coal consumed in the unit consists of the following CCRs: fly ash, bottom ash, and gypsum from the SO_2 scrubber. The solid waste is disposed in activities related to legacy pond closures or beneficially reused by marketing the CCRs to third parties. LG&E was issued an operating permit for the completed landfill in April 2023. Disposal of CCRs in the landfill will begin in 2024, following completion of pond closure activities.

Any hazardous waste generated at Trimble County is analyzed to confirm the hazardous nature and then profiled with LG&E's hazardous waste contractor for disposal by either incineration or placement in a certified Class C landfill. The facility maintains manifest and disposal records for all hazardous waste shipped off site.

Prairie State Energy Campus

Prairie State Units 1 and 2 are subject to CSAPR. The Prairie State units receive CSAPR NO_x and SO_2 allowances from Illinois' new unit set aside which meet most of its emission requirements. Any remaining allowances that are needed for compliance will be purchased.

The Prairie State units are subject to the MATS rule and are fully equipped for compliance.

Solid waste from these mine-mouth bituminous coal fired units consists of the following CCRs: fly ash, bottom ash, and gypsum from the SO_2 scrubber. The solid, dry waste and breaker waste from the mine is disposed at the near-field landfill. PSGC actively pursues alternative reuses of CCRs.

Hazardous waste generation at Prairie State is like Gibson Unit 5 and Trimble County. All hazardous wastes generated by Prairie State are properly characterized prior to disposal at appropriately permitted disposal facilities. The specific disposal facility chosen for a given waste depends on the nature of that waste.

Whitewater Valley Station

WWVS currently complies with the SO_2, NO_x, particulate matter, and opacity requirements of the Clean Air Act. WWVS complies with the CSAPR NO_x rules using low NOx burners and overfire air. IMPA expects its share of allowances to satisfy the NO_x and SO_2 emissions at WWVS. Solid waste from bituminous coal consumed in the unit consists of the following CCRs: fly ash and bottom ash. The solid waste is disposed of in a private offsite facility. RPL discontinued use of the surface impoundment as part of its plan for compliance with the CCR Rule prior to IMPA taking over operations.

WWVS is affected by the MATS rule and is fully equipped for compliance. A pulse jet fabric filter was installed in the 2010 time period and new sorbent and powder activated carbon injection systems were installed in late 2015 for compliance with the MATS Rule.

Small quantities of hazardous wastes may be generated from time to time from normal plant activities and may include spent solvents from parts cleaning and paint-related wastes, etc. WWVS normally operates as a Small Quantity Generator (<1000 kg per month). All hazardous wastes generated at WWVS are properly characterized prior to disposal at appropriately permitted disposal facilities. The specific disposal facility chosen for a given waste depends on the nature of that waste.

IMPA Combustion Turbines

All of IMPA's Combustion Turbine stations comply with the existing requirements of the Clean Air Act. This compliance is achieved through Title V Operating Permit restrictions on fuel consumption and the use of lean pre-mix fuel/air injectors and/or water injection for NO_x control. The stations meet CSAPR NO_x emission allowance requirements with allocated and purchased allowances. The stations comply with their respective Acid Rain Permits using the Excepted Methodologies in 40 CFR 75. (Appendices D and E) SO_2 allowances are either purchased or transferred from other IMPA-owned source allocations.

The Anderson and Richmond turbines can operate on pipeline natural gas or No. 2 ultra-low sulfur fuel oil. There is no significant environmental effect from solid waste disposal or hazardous waste disposal. Each plant has chemical storage for use in its demineralized water treatment plant. At times, hazardous waste may need to be disposed of when the chemical tanks are cleaned. A licensed contractor is hired to do this cleaning, remove the waste, and properly dispose of the waste. Infrequently, oily waste may be removed from collecting tanks located at the site. This waste is also disposed of using properly licensed vendors. Other waste disposal is similar to household waste and is removed by a licensed refuse removal company.

The Georgetown units are single fuel units that operate solely on pipeline natural gas. There is no chemical storage on site and the plant's parts washer contains non-hazardous solvent. There is no significant environmental effect from solid waste disposal or hazardous waste disposal. Most waste disposal consists of waste like household waste and is removed by a licensed refuse removal company. There may be, at infrequent times, oily waste removed from onsite collecting tanks. This waste is also disposed using properly licensed vendors.

8.2 Compliance with Future Rules

IMPA makes no assumptions as to future environmental rules or laws. For purposes of this analysis, it is assumed that all future resource options comply with the existing environmental rules in place at the time of installation.

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9 TRANSMISSION AND DISTRIBUTION

9.1 FUTURE TRANSMISSION ASSUMPTIONS

As noted previously, IMPA is a member of MISO as a TO within the DEI area and is a TDU within the NIPSCO and Centerpoint/Vectren areas. IMPA is also a TDU receiving transmission service from PJM for its loads in that footprint.

MISO performs all the transmission system planning for the facilities under its operational control, which includes most of the JTS. In the DEI load zone, DEI performs any additional transmission system planning functions on behalf of the three owners of the JTS. IMPA participates in the joint owners' Planning Committee, which reviews major system expansions planned by DEI, with DEI taking responsibility for filing the FERC Form 715 on behalf of the JTS. IMPA assists its members where needed in determining when new or upgraded delivery points are required and coordinates any studies, analyses, or upgrades with other utilities.

Rates for MISO and PJM area-specific NITS and ancillary services were escalated to reflect increased cost for transmission service over the study period. Additionally, costs for PJM's Transmission Enhancement Charge, MISO's Network Upgrade Charge (Schedule 26) and Multi Value Project Charge (MVP) adder (Schedule 26a) were based on projections provided by the RTOs.

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10 SOFTWARE OVERVIEW / DATA SOURCES

IMPA utilizes Encompass by Anchor Power Solutions, MCR-FRST by MCR Performance Solutions, LLC, and various custom-made risk analysis tools to perform its resource planning studies.

10.1 ENCOMPASS

Encompass is a fully integrated planning model that allows the user to generate market capacity expansion studies, market price studies, and portfolio optimization in the same platform utilizing the same database. By not having to move data between independent modules, both time and accuracy are improved. A distinct feature of Encompass is that while it can be utilized to model entire RTOs/ISOs, IMPA is able to use it to model just its power supply portfolio against the market. This makes for a more flexible modeling suite than the previous model, which handled the entire Eastern Interconnect.

10.2 MCR-FRST

MCR-FRST by MCR Performance Solutions, LLC is an Excel-based financial model IMPA utilizes to develop the final revenue requirements for its portfolio. MCR-FRST takes operational outputs from Encompass and combines them with other financial inputs to create IMPA's annual revenue requirements and rates.

10.3 RISK ANALYSIS TOOLS

To assess the risk of the various plans, IMPA utilizes a variety of analytical tools and techniques. When selecting a preferred plan, strong consideration is given for the robustness of the plan in addition to the relative cost, rate impact, and potential risk of the plan.

10.4 External Data Sources

IMPA's database uses a mix of publicly available forecasted information and IMPA proprietary information from a variety of sources.

Table 10 External Data Sources

Source Title	Publishing Address
Annual Energy Outlook 2022 & 2023	U.S. Energy Information Administration Office of Communications, EI-40 Forrestal Building, Room 1E-210 1000 Independence Avenue, S.W. Washington, DC 20585
Velocity Suite Database	ABB/Hitachi 1495 Canyon Blvd, Suite 100 Boulder, CO 80302
S&P Global Market Intelligence; SNL Energy Data	SNL Financial LC PO Box 2124 Charlottesville, Virginia 22902
Midcontinent Independent System Operator	Midcontinent ISO (MISO) 701 City Center Drive Carmel, IN 46032
State Utility Forecasting Group-MISO Load Forecast	Mann Hall, Room 160 203 South Martin Jischke Dr. West Lafayette, IN 47907
Horizons Energy Market Advisory	https://www.horizons-energy.com/advisory-services/advisory-service/
NREL Cost Projections for Utility Scale Battery Storage	1503 Denver W. Parkway Golden, CO 80401
PJM Interconnection	2750 Monroe Boulevard Audubon, PA 19403
St. Louis Federal Reserve Bank FRED	Broadway and Locust, 1 Federal Reserve Bank Plaza St. Louis, MO 63102
Nodal Exchange, LLC	8065 Leesburg Pike 7th Floor Vienna, Virginia 22182

11 2023 INTEGRATED RESOURCE PLAN PRE-WORK

In late 2021, IMPA switched power supply models from AuroraXMP to Encompass by Anchor Power Solutions. In order to gain familiarity with the model and prepare for the 2023 IRP, IMPA ran an informal integrated resource plan through the newly acquired model utilizing EIA costs for new generation and observable market forwards in order to estimate what the ideal replacement for an eventual Gibson 5 retirement would be.

The table below illustrates the capital costs utilized for the resources studied in the pre-work model runs. Recall that this data was gathered in early 2022 and reflects 2020 EIA estimates.

Table 11 IRP Pre-work CAPEX Assumptions

	New Wind	New Solar	New CT	New CC
Base Year	2020	2020	2020	2020
Inflation	2.2%	2.2%	2.2%	2.2%
Base Year CAPEX/kw (pre-ITC/PTC)	$ 1,517	$ 1,062	$ 761	$ 1,000
FOM	30	15	10	13.25
Annual NCF	31%	21%	10%	50%
Capacity Credit	15%	60%	95%	95%

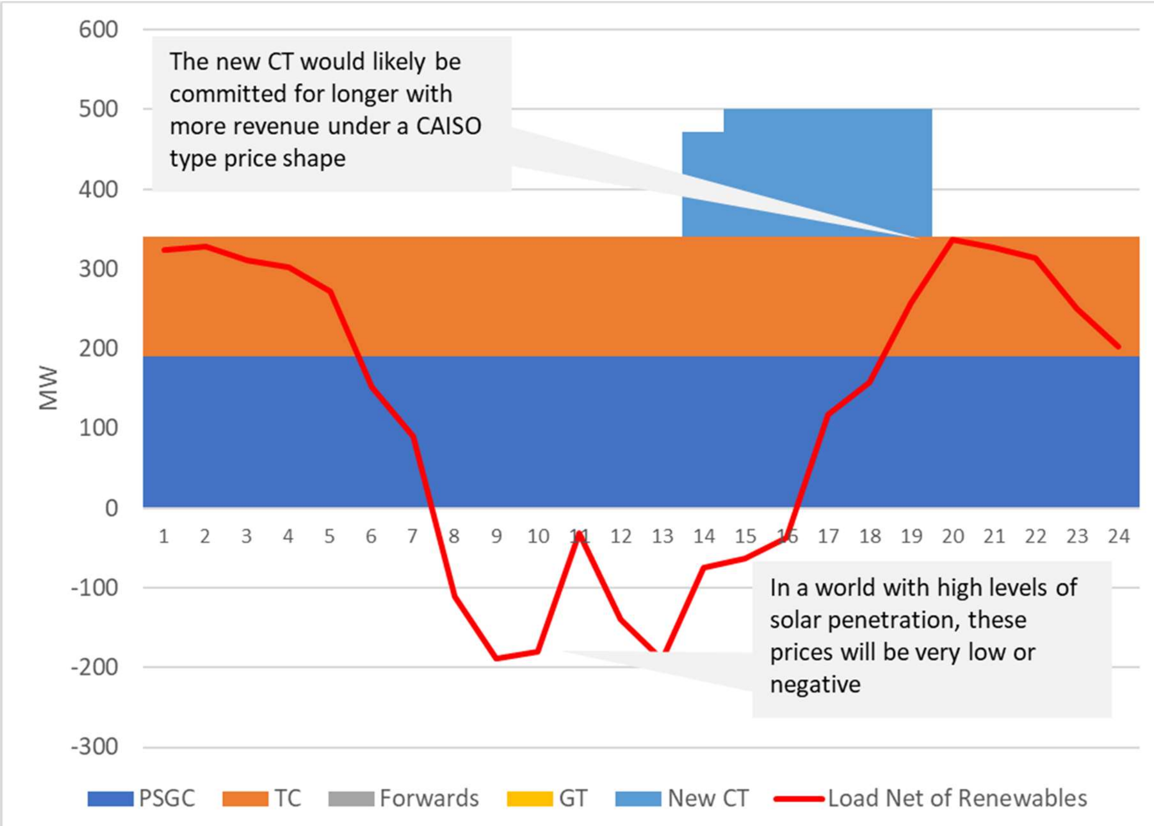
A key concern of IMPA at this point in the planning process was the impact on solar in the IMPA portfolio. During the preparation work, IMPA had planned to have 350 MW of utility scale solar under contract, in addition to IMPA's solar program. Further compounding this concern was the composition of the MISO interconnection queue, which was and still is dominated by solar generation. Table 12 below shows total interconnection requests by MW and fuel for a three-state area.

Table 12 MISO Interconnection Queue by Resource and State

Resources/State	Illinois	Indiana	Kentucky
Battery Storage	5,953	7,158	825
Gas	325	581	696
Hybrid	8,472	5,314	352
Solar	14,499	15,924	2,186
Wind	4,140	2,102	200
Total MW	***33,389***	***31,077***	***4,259***

Given the potential for the generation stack in MISO to be heavily dominated by intermittent resources, it follows that new generation should be both dispatchable and flexible. The figure below illustrates sample hourly data of IMPA thermal resources against load net of renewables.

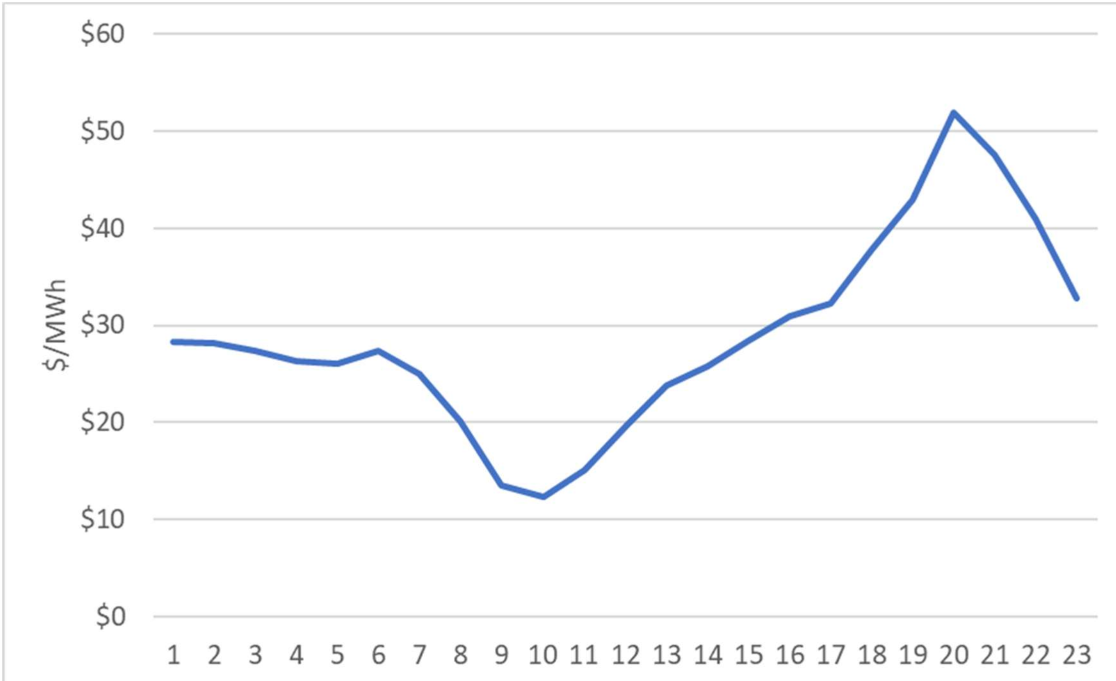
Figure 16 Thermal Resources vs. Net Load



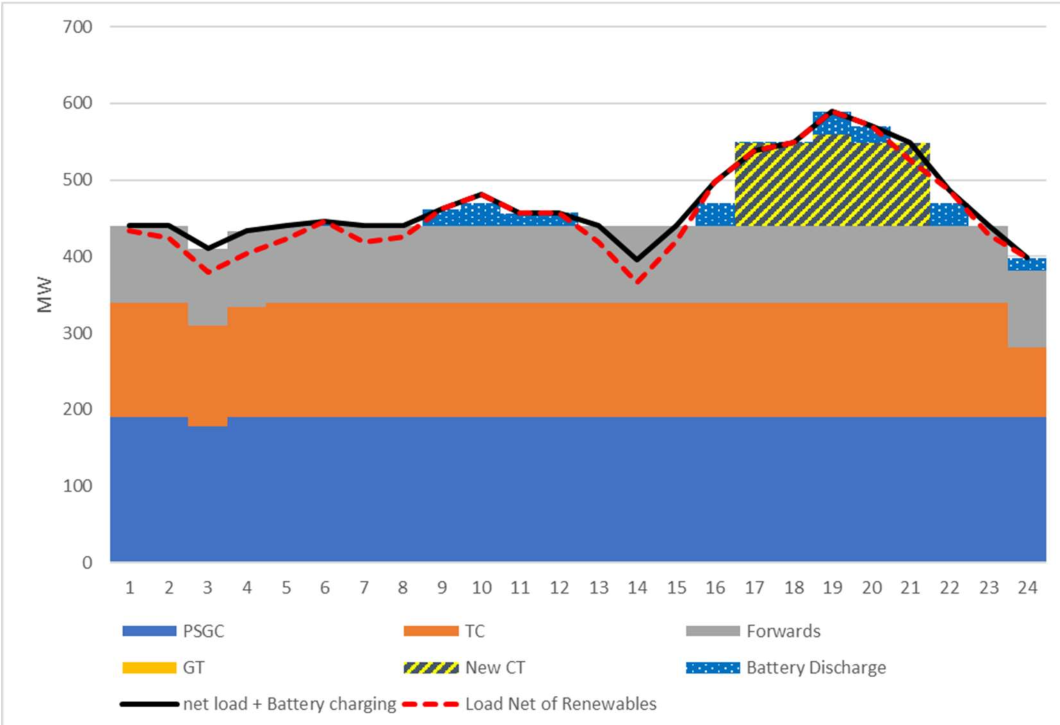
As shown above, the newer, more efficient CT is dispatched during traditional peak hours while the existing Georgetown units are not dispatched at all. Presumably, in a world flush with solar, prices during HE 13-15 would potentially be uneconomic for CT dispatch as solar resources with zero marginal cost (or even negative) dominate the resource stack. Using historical MISO price shapes, the model potentially overstates the value of renewable generation and understates the value of CT generation. As a sensitivity to this, IMPA re-optimized the portfolio using price shapes from the California Independent System Operator (CAISO) in order to test the value of solar in a market that had high levels of solar penetration.

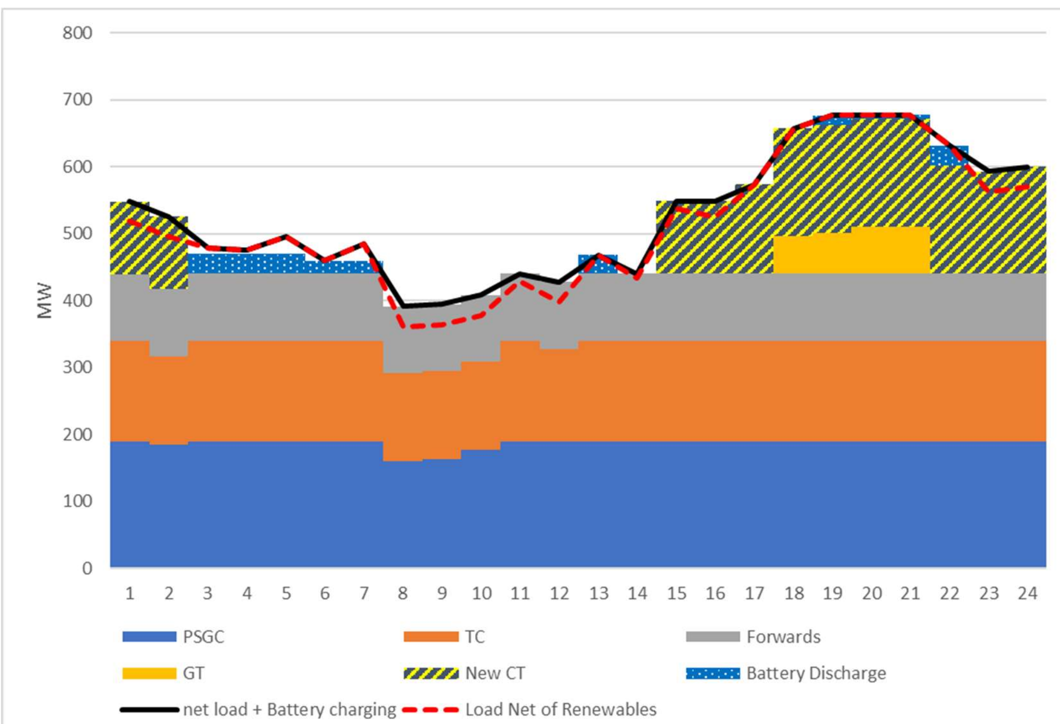
The figure on the following page shows a representative price shape for CAISO in summer using historical prices.

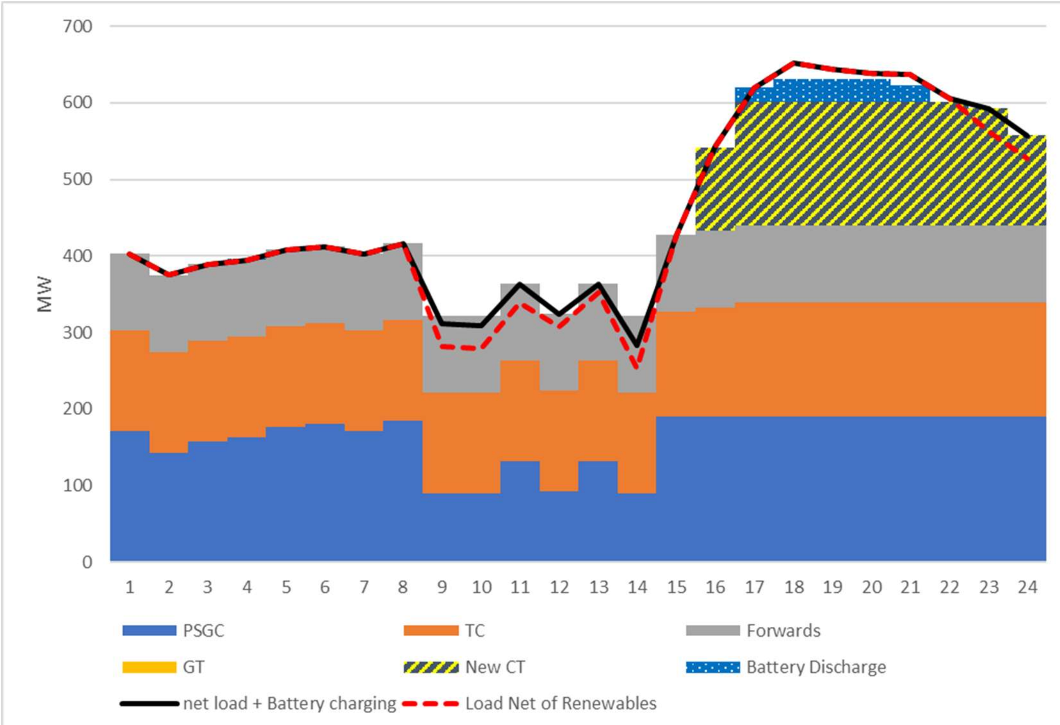
Figure 17 CAISO Price Shape



Using this shape, applied to Indiana Hub prices in the model, allowed for a new optimization to be run and evaluated in a similar manner as the previous example. In this particular case, the model selected a CT, a small battery, and a 100 MW wind project. In the following pages (11-70 through 11-71), we show three sample days of this newly optimized portfolio in July 2030.


700
600
500
400
300
200
100
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
PSGC
TC
Forwards
GT
New CT
Battery Discharge
net load + Battery charging
Load Net of Renewables


800
700
600
500
400
300
200
100
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
PSGC
TC
Forwards
GT
New CT
Battery Discharge
net load + Battery charging
Load Net of Renewables



In this particular portfolio, the CTs are needed to fill evening load requirements as load, net of renewables, increases (i.e., solar declines). In addition, it selected much less solar than in the original optimization. In the event the market becomes flooded with renewables, there is increased risk that an operationally inflexible resource becomes stranded as the unit is forced to remain online during periods of potential oversupply.

The conclusions drawn from the IRP pre-work were that the IMPA portfolio would need a resource that was highly flexible and dispatchable, particularly in a future where net loads are expected to peak during hours where solar is not available and prices are likely to be high in response to higher net demand.

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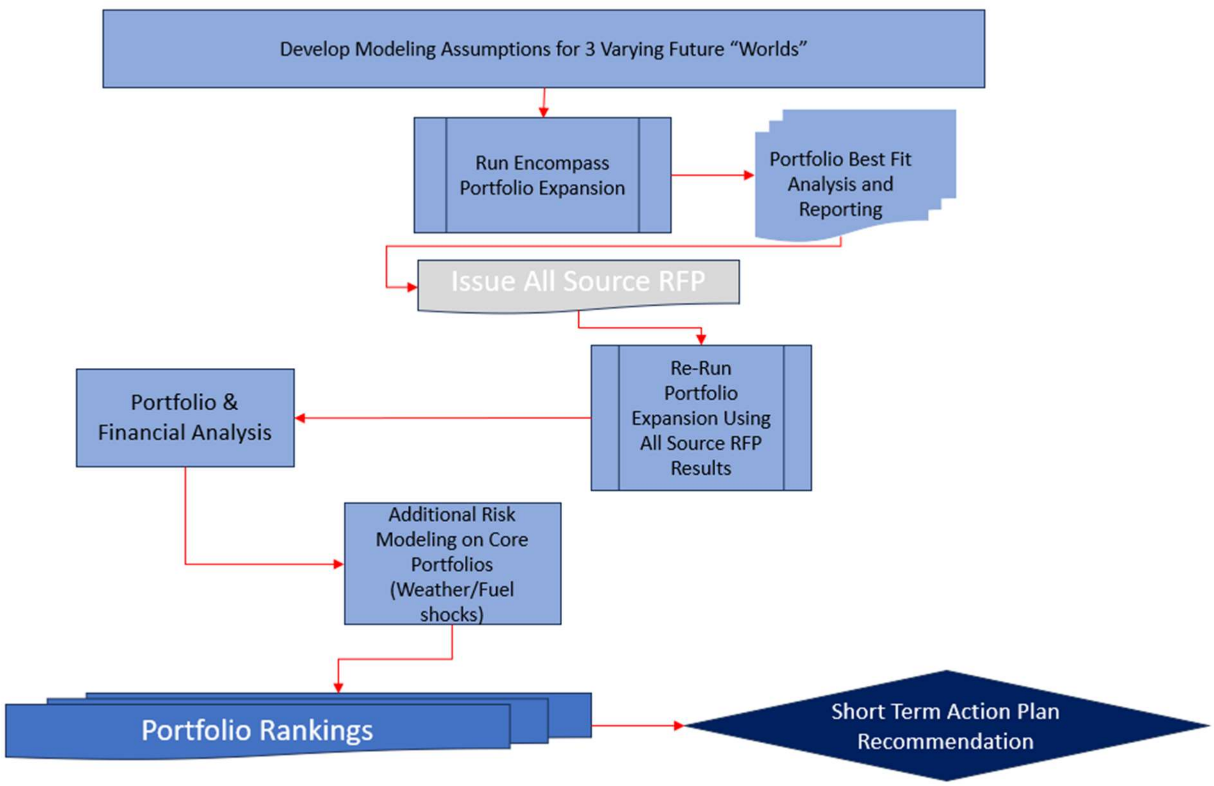
12 BASE CASE

IMPA creates cases, or scenarios, as a way to think about the future. Scenario planning is a proven tool to better anticipate and respond to future risks and opportunities. IMPA develops stories about how the future might unfold by building alternate views of the future given different political, economic, regulatory, or technological assumptions.

12.1 IRP Scenario Process

A key aspect of scenario planning for an electric utility is to transform the scenario narrative into electricity market characteristics that can be incorporated into the IRP process. These characteristics are then incorporated into the long-term market model. The scenarios can significantly affect the type and timing of resource additions, and thus, long-term capacity and energy prices. Ideally these scenarios and their expansion serve as "book-ends" that examine a variety of outcomes.

Figure 18 IRP Flowchart



12.2 CARBON POLICY

For IMPA's 2023 IRP, IMPA opted to not assume any national level tax or policy constraint. This is a departure from IMPA's previous IRPs, where some level of CO2 tax was contemplated. This decision stems from years of talk around a national carbon tax and debate around what such a scheme would look like, but nothing amounting to meaningful legislation. In fact, traction in the previously robust Regional Greenhouse Gas Initiative (RGGI) may be slipping as Governor Glenn Youngkin has proposed regulation to withdraw Virgina from that market. Central to Youngkin's argument is that RGGI is just a hidden tax that does little to curb emissions.[12]

Acting to further table action on carbon policy, at least in the form of a tax, are a variety of political tussles over implementation and auction revenue usage. Add to those obstacles, the headwinds of the current inflationary environment and global concerns over energy security in the face of Russia's invasion of Ukraine, a carbon tax seems like a political non-starter. [13]

In May of 2023, roughly 5 months into IMPA's IRP modeling efforts, the Environmental Protection Agency announced what is being called "The Clean Power Plan 2.0." As proposed, this plan would require existing coal units to be retired by 2040 unless they reduce Greenhouse Gas Emissions (GHG) by 90%. In addition, the plan places GHG restrictions on large natural gas fired units with capacity factors of 50% and above. These restrictions would require the installation of carbon capture and sequestration (CCS) technology or blend natural gas with "green" hydrogen. Fuel blending would need to be 96% hydrogen by 2038. New gas fired peaking units with capacity factors of under 20% are largely outside the scope of the new rule. [14]

Initial comments on this rule were mixed at best, with the most notable comments coming from a coalition of ISO/RTOs. ERCOT, MISO, PJM, and SPP jointly commented that "Although each region is working to facilitate a substantial increase in renewable generation, the challenges and risks to grid reliability associated with a diminishing amount of dispatchable generating capacity could be severely exacerbated if the proposed rule is adopted." [15]

Given the breadth of generally negative comments from a diverse group of stakeholders, IMPA has assumed for the purposes of this IRP that the "Clean Power Plan 2.0" as currently proposed will not be enacted.

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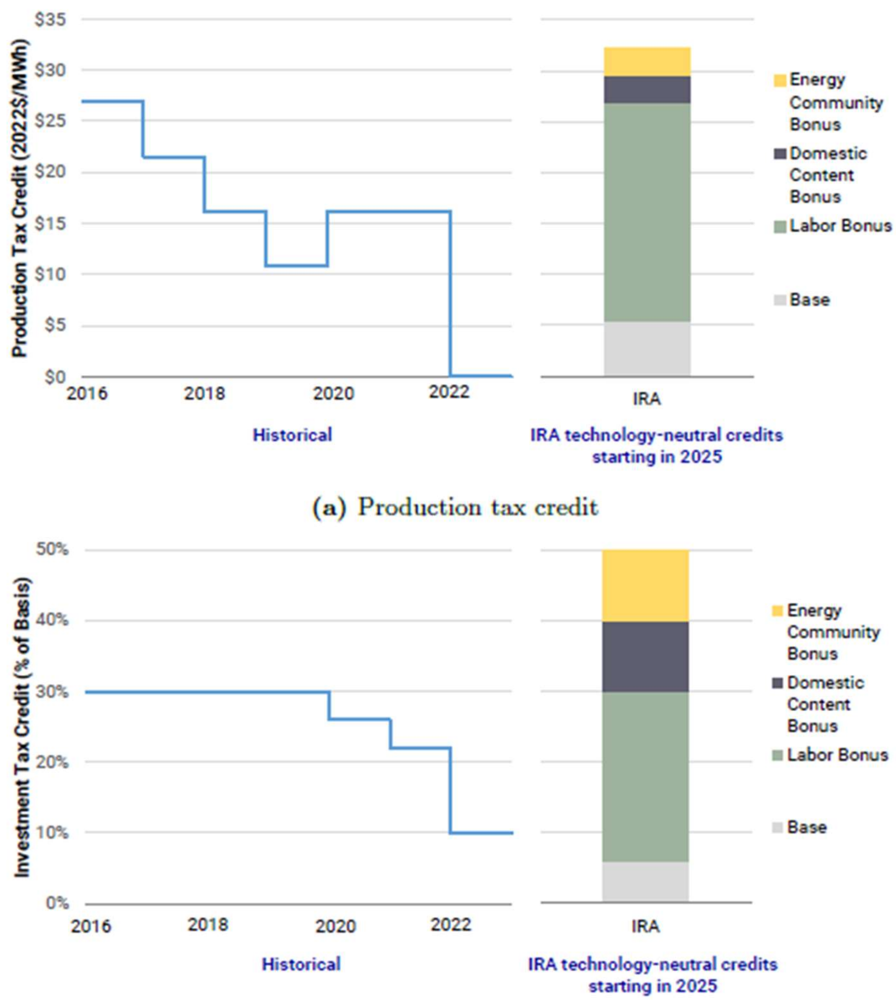
[12] https://www.vpm.org/news/2023-06-07/virginia-rggi-repeal-air-board-vote-climate-change-reggie
[13] https://www.wilsoncenter.org/article/carbon-pricing-enters-middle-age
[14] https://www.sidley.com/en/insights/newsupdates/2023/5/epa-publishes-new-proposed-greenhouse-gas-standards-for-fossil-fuel-fired-power-plants
[15] RTO Insider, August 15, 2023.

Despite lack of traction on a policy "stick" to curb CO_2 emissions, policy "carrots" seem much more appealing to voters and legislators. At the time of writing, the Inflation Reduction Act of 2022 (IRA) was celebrating its one-year anniversary of passage. For the purposes of this IRP, the most relevant feature of this act are the treatment of Investment and Production Tax Credits (ITC and PTC, respectively). Effectively the IRA seeks to give renewable/carbon neutral energy projects a clearer line of sight on tax incentives.

The figure below shows the PTC and ITC under previous iterations as compared to under the IRA.

Figure 19 ITC and PTC Provisions of the IRA



Source: https://www.brookings.edu/wp-content/uploads/2023/03/BPEA_Spring2023_Bistline-et-al_unembargoedUpdated.pdf

One of the key features of the tax credits in the IRA is the transition from technology specific credits to credits for any carbon neutral technology beginning in 2025. This allows for some project level optimization depending on the capital intensity of the given project versus its production potential. In addition, the credits will remain in force until the later of 2032 or whenever power sector GHG emissions reach 25% of their 2022 emissions. Once this threshold is reached, a three-year phase out begins. According to Wood Mackenzie, this threshold isn't expected to be reached until 2044[16]. For the purposes of IMPA's 2023 IRP, this effectively renders them permanent.

Table 13 illustrates IMPA's base case for tax credits by technology type.

Table 13 Assumed Tax Credit Application Under the Inflation Reduction Act

Technology	Credit Type	Credit Amount
Small Modular Reactor	ITC	35%
Solar PV	ITC	35%
Storage	ITC	35%
Wind	PTC	$27.50/MWh

Across technology types, IMPA estimates that for the foreseeable future, projects should be at least able to qualify for the base rate plus the labor requirement bonus. Incremental bonuses are available to projects that meet domestic content requirements or are located in low-income or "energy communities." However, at the time of writing Treasury guidance on these bonus features was still pending.

12.3 ISO/RTO MARKET BACKDROP

12.3.1 MISO & PJM Capacity Market Reforms

Perhaps the most challenging aspect of the 2023 IRP process has been dealing with uncertainty stemming from ISO/RTO market changes. As discussed previously, IMPA has roughly 2/3 of its member load in MISO with the remaining 1/3 in PJM. The most critical change in both markets stems from capacity market reform and resource accreditation reform.

In MISO, prior to Planning Year 2023-2024, MISO's planning resource auction was focused on procuring enough capacity to meet summer peak load plus additional reserves. Reserve requirements were (and still are), set by MISO's Loss of Load Expectation Working Group

[16] https://www.woodmac.com/news/opinion/IRA-tax-credits-for-renewables/

(LOLEWG), with reserve margins determined by some acceptable loss of load threshold, typically a loss of load of less than or equal to 1 day in 10 years.

For Planning Year 2023-2024, MISO changed to a seasonal construct with four distinct seasons (Summer, Fall, Winter, Spring), and four distinct planning reserve margins. The justification for this construct stemmed from two concerns raised by MISO. The first was MISO's experience in seeing periods of stress on the grid outside the traditional summer hours. These periods are defined by either the need to declare Maximum Generation Alerts or periods of low operating margin.

Table 14 below shows a sample of these hours across a three-year sample.

Table 14 MISO Resource Adequacy (RA) Hours

MISO RA Hours

Month/Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0	0	0	0	0	0	1	1	4	4	2	2	1	1	0	0	0	1	4	4	2	1	1	1
2	1	0	0	0	0	0	1	4	9	7	7	6	6	5	3	1	1	2	4	7	4	3	1	0
3	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	2	4	4	5	4	2	2	2	1	1	1	0	0	1	2	1	0	0
5	0	0	0	0	0	0	0	0	0	1	2	4	6	12	15	14	16	15	13	7	5	1	0	0
6	0	0	0	0	0	0	0	0	0	0	0	1	3	4	6	7	9	9	7	5	2	2	0	0
7	0	0	0	0	0	0	0	0	0	0	0	1	6	9	12	13	18	17	9	1	0	0	0	0
8	0	0	0	0	0	0	0	0	0	1	1	1	3	4	8	10	11	9	5	1	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	1	3	4	8	11	11	12	7	3	1	0	0	0
10	0	0	0	0	0	0	0	2	4	3	3	5	8	9	9	9	11	11	11	7	4	0	0	0
11	0	0	0	0	0	0	0	3	3	2	1	0	0	0	0	0	0	0	2	1	0	0	0	0
12	0	0	0	0	0	0	0	2	5	3	3	2	0	0	0	0	1	1	2	3	3	3	1	0

Source: MISO

As illustrated, MISO has experienced most of its emergency/tight hours over the summer months during traditional peak hours, however, it is worth noting the emergence of emergency hours in the fall and winter.

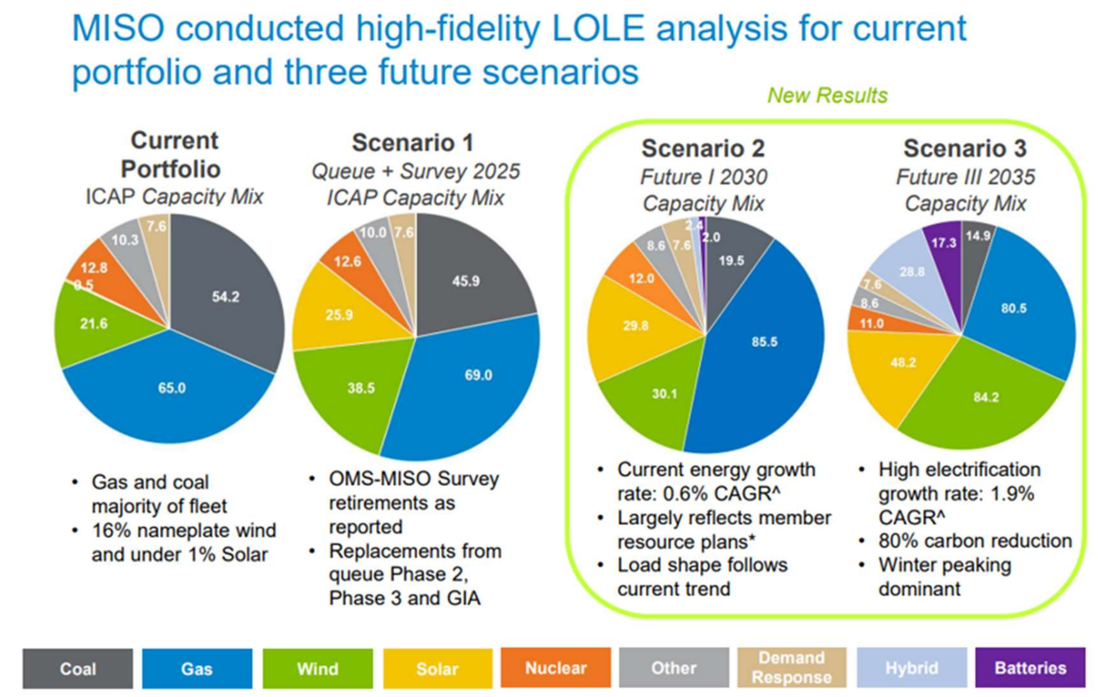
The second driver of MISO's decision to move to a seasonal construct is the looming change in the resource mix that is expected. These expectations are gathered from the MISO OMS-Survey and MISO member resource plans over the intermediate and long-term planning horizons. [17]

[17] https://cdn.misoenergy.org/20230714%20OMS%20MISO%20Survey%20Results%20Presentation629607.pdf

Part of MISO's planning process prior to the adoption of the seasonal construct was to conduct Loss of Load Expectation (LOLE) Studies on its current portfolio, it's projected 2025, portfolio and two additional scenarios reflecting long-term resource plans of members.

Figure 20 illustrates these scenarios and the resource mixes assumed.

Figure 20 MISO LOLE Studies



Source: MISO

Ultimately, concerns arise with how to best handle reliability issues as intermittent resources become a major share of the generation mix.

These LOLE studies provided useful information on how periods of risk shift with the changing resource portfolio. These are illustrated in Figure 21.

Figure 21 MISO LOLE Studies - Periods of Risk

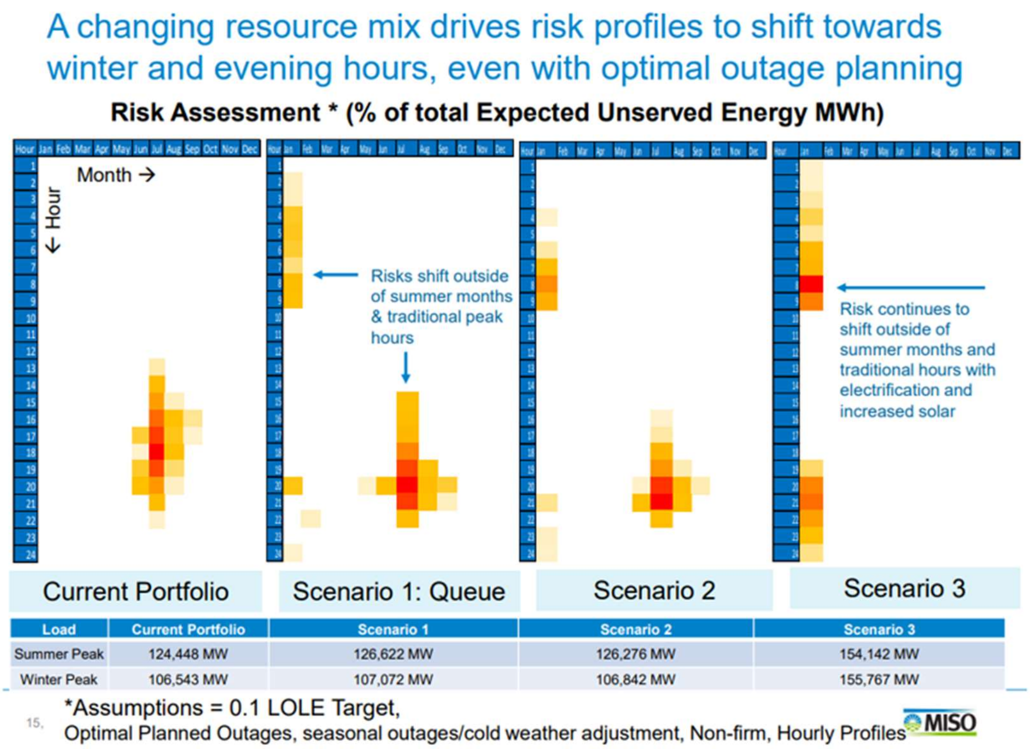


Figure 21 shows how the current portfolio experiences risks centered on summer afternoons, while Scenarios 1-3 show how the risk moves away from those hours and into winter mornings and summer nights as intermittent generation technologies increase their market share.

These preliminary studies shaped MISO's planning reserve margin requirements for the first seasonal PRA held for Planning Year 2023-2024. These reserve margins, along with historical single season reserve margins are show in Table 15 on the following page.

Table 15 MISO Planning Reserve Margins

Season	Planning Year 19-20	Planning Year 20-21	Planning Year 21-22	Planning Year 22-23	Planning Year 23-24
Summer	7.9%	8.9%	9.4%	8.7%	7.4%
Fall	7.9%	8.9%	9.4%	8.7%	14.9%
Winter	7.9%	8.9%	9.4%	8.7%	25.5%
Spring	7.9%	8.9%	9.4%	8.7%	24.5%

Since MISO does not complete its LOLE modeling until late fall of the calendar year (for the upcoming planning year), IMPA has no way of knowing or predicting what reserve margins will come out of that study. Therefore, IMPA has assumed seasonal reserve margins that are the same as Planning Year 23-24 shown in Table 15 and that those reserve margins stay constant over the IRP horizon.

Further confounding the planning process during MISO's move to a seasonal planning construct is a change to their resource accreditation methodology. Historically MISO has credited resources their Installed Capacity (ICAP) less their equivalent forced outage rate (EFORd). Under the new seasonal construct, MISO has chosen to move to a Seasonal Accredited Capacity (SAC) methodology, whereby resources are essentially graded on how well they performed during the previous three years' selection of Resource Adequacy (RA) Hours. RA Hours are tallied anytime MISO has declared an emergency or during the top 3% of tightest operating margin hours observed. Since the assessment period is a rolling three-year lookback, assessing a unit's SAC over a 20+ year planning horizon is impossible.

Additional refinements in this process are currently being proposed by MISO that would diminish the resource accreditation of renewable resources as well, with the most drastic impact being for solar resources. [18]

PJM as well, has faced challenges with its capacity market design and is currently in the midst of a near complete overhaul of its Base Residual and Incremental Auctions. While no single reform

[18] https://cdn.misoenergy.org/20230822-23%20RASC%20Item%2009bi%20Resource%20Accreditation%20Presentation%20(RASC-2020-4,%202019-2)629918.pdf

package has gotten traction at the time of writing, the trajectory of reforms in PJM seems to place PJM on the path of a two-season capacity market while allowing for a "more granular" approach at a later date. [19]

PJM is also contemplating changes to how it models reserve requirements. When IMPA began its modeling in early 2023, IMPA assumed the going forward reserve margin would stay around the 2022 Reserve Requirement Study (RRS) results, shown below in Table 16[20].

Table 16 PJM Planning Reserve Margins

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Recommended FPR
2022	2023 / 2024	14.87%	**14.9%**	4.87%	**1.0930**
2022	2024 / 2025	14.75%	**14.8%**	4.83%	**1.0926**
2022	2025 / 2026	14.72%	**14.7%**	4.81%	**1.0918**
2022	2026 / 2027	14.70%	**14.7%**	4.81%	**1.0918**

However, in late 2023, PJM released its initial RRS, using a revised methodology. Under the revised methodology, results from two models will be presented to stakeholders for endorsement at a later date. While IMPA has no capacity need in the PJM market until Planning Year 2034-35, this revision suggests that the trend of higher reserve margins in all ISO/RTOs will likely be around in the next IRP cycle. Table 17 illustrates the potential, new reserve margins using the new methods. To reiterate, IMPA is using the reserve margins illustrated in Table 16 until more clarity is achieved.

[19] https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230823/20230823-item-01a---20230823-cifp-stage-4---pjm-exec-summary.ashx
[20] https://www.pjm.com/-/media/planning/res-adeq/2022-pjm-reserve-requirement-study.ashx

Table 17 PJM Potential Planning Reserve Margins

2023 RRS Study results - PRISM:

RRS Year	Delivery Year Period	Calculated IRM	Average EFORd	Recommended FPR*
2023	2024 / 2025	**17.7%**	5.10%	**1.1170**
2023	2025 / 2026	**17.7%**	5.09%	**1.1171**
2023	2026 / 2027	**17.7%**	5.08%	**1.1172**
2023	2027 / 2028	**17.6%**	5.06%	**1.1165**

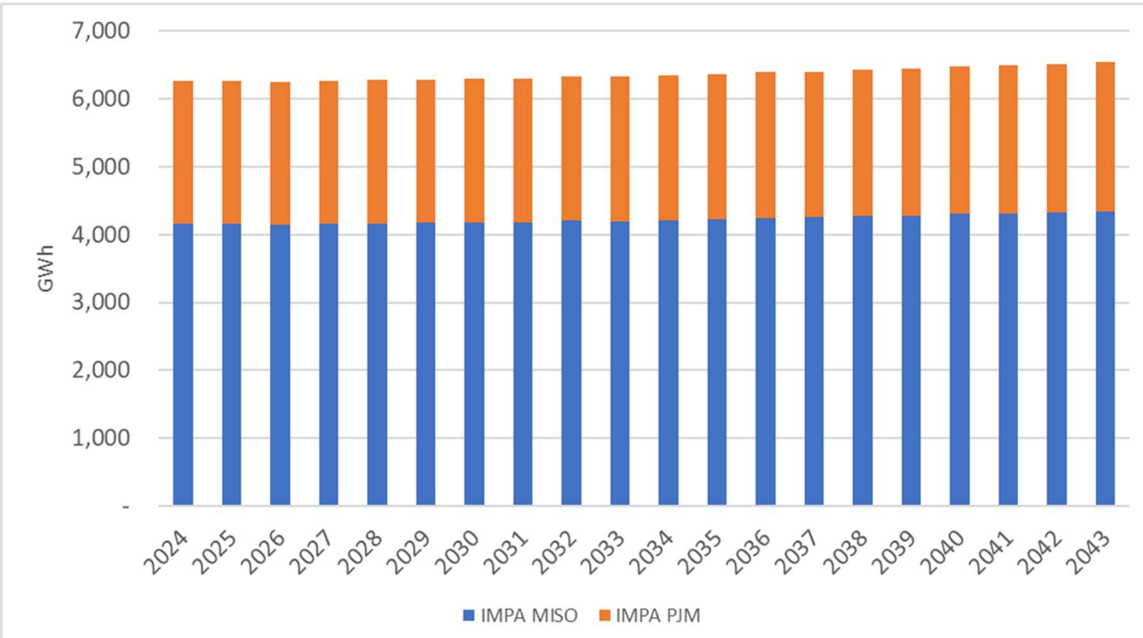
2023 RRS Study results - Hourly Model:

RRS Year	Delivery Year Period	Calculated IRM	Average EFORd	Recommended FPR*
2023	2024 / 2025	**18.5%**	5.10%	**1.1246**
2023	2025 / 2026	**18.4%**	5.09%	**1.1237**
2023	2026 / 2027	**18.4%**	5.08%	**1.1239**
2023	2027 / 2028	**18.3%**	5.06%	**1.1231**

12.4 Load Forecasts – IMPA

In IMPA's 2020 IRP, IMPA utilized a model that required forecasts to be developed and input into the Aurora model in order to run a market expansion on the entire Eastern Interconnect. For the 2023 IRP, IMPA is utilizing Encompass by Anchor Power Solutions. Utilizing Encompass for the IRP allows IMPA to focus solely on portfolio assumptions as inputs. Consequently, IMPA is only required to develop and utilize its base case forecast set forth in Section 6 of this IRP document. Figure 22 below illustrates the long term expected energy forecast for IMPA's members.

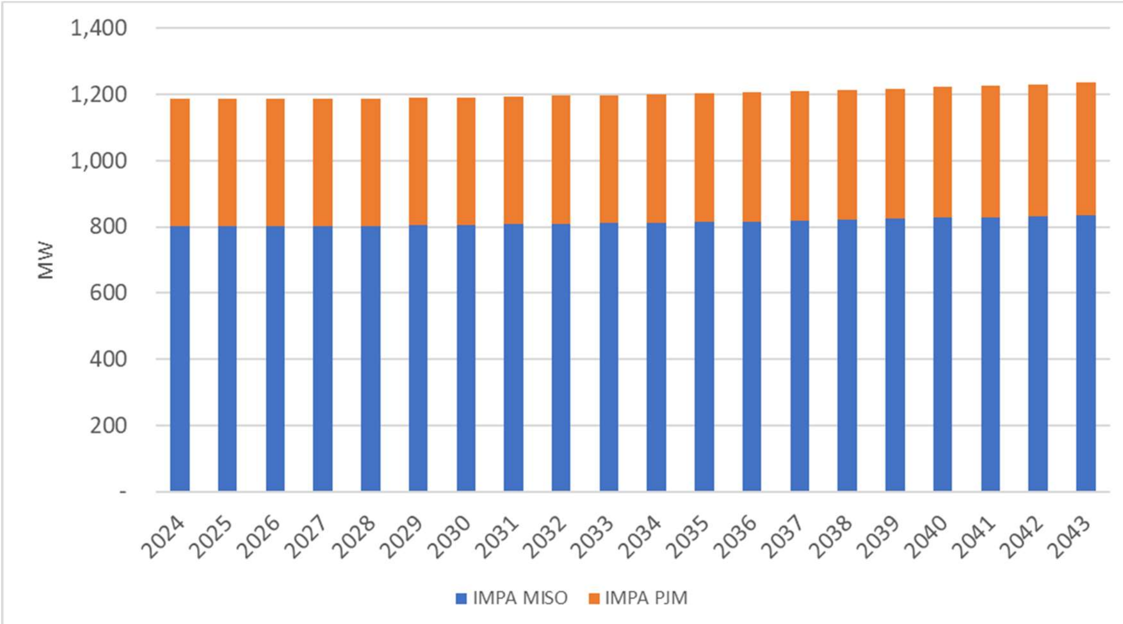
Figure 22 IMPA Long Term Energy Forecast - Base Case



Under the base case forecast, long term energy requirements are only expected to grow at a compound annual growth rate (CAGR) of .21% per year, which includes the assumed rate of EV penetration discussed in Section 6 of this document.

Peak demand is expected to track with energy, with a compound annual growth rate of .20% per year. Figure 23 shows the long-term demand forecast for the base case.

Figure 23 IMPA Long Term Demand Forecast - Base Case



It is important to distinguish between these load forecasts and how each ISO/RTO that IMPA operates in determines IMPA's load obligation. These forecasts represent non-coincident peaks for each of IMPA's five load areas and consequently do not reflect IMPA's planning obligation in each market. Further discussion on the planning obligation can be found in Section 12.8.

12.5 Generation and Technology Costs

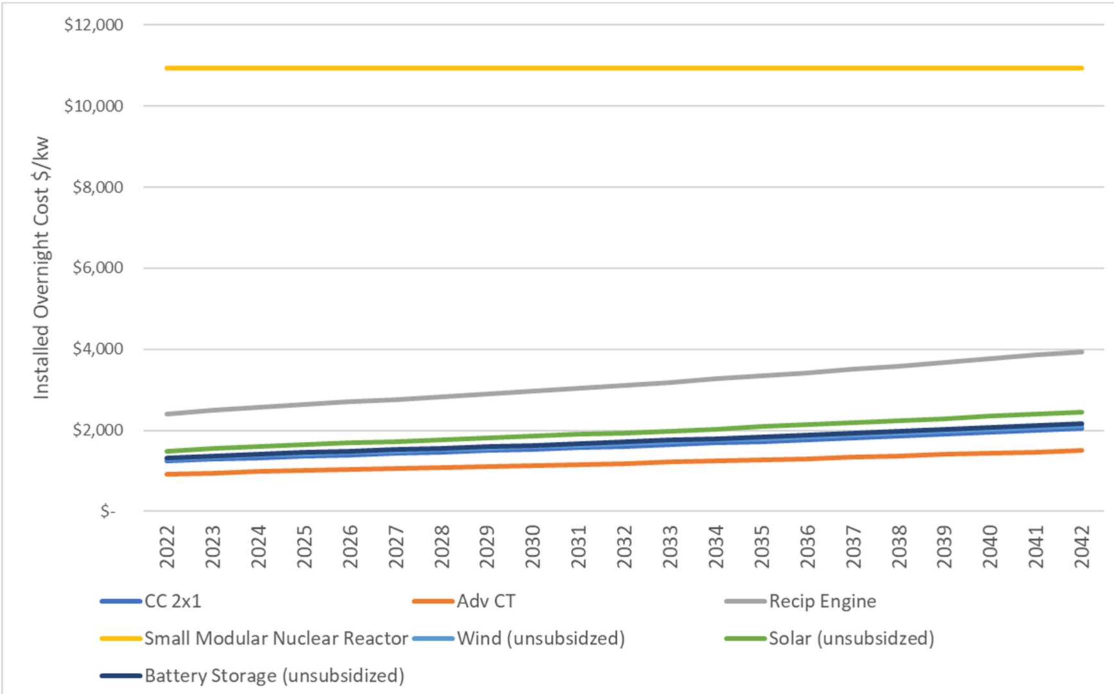
As part of IMPA's 2023 IRP process, IMPA did preliminary studies using generic resources based on EIA's Annual Energy Outlook to establish portfolio needs based on current market conditions. This was effectively a refresh of the pre-work referenced in Section 11 but utilizing updated EIA numbers.

Table 18 Generation Costs for New Generation Technology

Tech	NEW AEO Cost - 2022 $/kW	Tech Optimism Factor	Total Base Cost	VOM (2022 $/MWh)	Fixed O&M (2022 $/kW-yr)
CC 2x1	$1,237	1	$1,237	$2.73	$13.05
Adv CT	$912	1	$912	$4.81	$7.49
Recip Engine	$2,392	1	$2,392	$6.09	$37.62
Small Modular Nuclear Reactor	$9,949	1.1	$10,944	$3.21	$101.65
Wind (unsubsidzed)	$1,286	1	$1,286	$0.00	$28.18
Solar (unsubsidzed)	$1,492	1	$1,492	$0.00	$16.32
Battery Storage (unsubsidized)	$1,317	1	$1,317	$0.00	$26.53

The larger of these resources were broken into 50 MW blocks to allow the model more latitude in optimization for the IMPA portfolio. In addition, IMPA modeled Wind and Solar resources as Purchase Power Agreements based on IMPA's in house project finance model. This model takes unsubsidized CAPEX and estimated return requirements for both the Tax Equity and Sponsor portions of the capital stack, then solves for a PPA price that meets these return objectives. This has proved to be a good way to estimate the value of renewable projects within the marketplace.

Figure 24 New Generation - Overnight Costs ($/kw) – Unsubsidized



As noted in the introduction, IMPA has direct experience with project delays and cost increases in the renewable space, specifically with solar. Also, wind development seems to be nearly non-existent in MISO and PJM. Considering projects that are currently in early-stage development will probably face interconnection delays or possibly supply chain issues, IMPA estimates the earliest a project could become commercial is 2027. **Given this first-hand experience with the challenges of executing power supply plans since the last IRP, IMPA opted to run an All-Source Request for Proposals to see what potential for new or existing projects existed and their economics.** These results are discussed in more detail in Section 12.7.

Energy Efficiency

Energy Efficiency programs were modeled as selectable resources that were effectively load decrements at incrementally higher costs. Specifically, the initial block of energy efficiency was modeled in 1/4 MW increments, with the initial 1/4 being modeled at IMPA's current cost of implementation. This price is $237/kW. Additional increments were "priced" on an increasing basis reflecting difficulty in finding additional efficiencies. In addition, given IMPAs status as a wholesale supplier, market potential is very difficult to gauge as most energy efficiency potential lies with the retail customer.

Demand Response

Since the last IRP cycle, IMPA has engaged with leading Demand Response aggregators in order to better understand how DR programs could work for IMPA members who have industrial loads that may be eligible. These conversations have led IMPA to begin the process of re-working its demand response tariff in order to better facilitate DR enrollments. For this IRP and based on preliminary investigations, pricing for DR programs will ultimately be negotiated between IMPA, the member, and the load requesting to be enrolled. IMPA has assumed $700,000 in program costs per year for up to 10 MW of firm capacity. Depending on uptake, this equates to between $70/kW to $140/kW "installed" cost. These are modeled as selectable resources in the Encompass model.

12.6 Forward Prices

Given IMPA's change from a model that required feedstock input assumptions for the entire Eastern Interconnect to one that modeled purely IMPA portfolio characteristics, the principal assumption for resource optimization is a forward expectation for power prices. IMPA utilizes three different sources for arriving at forward power prices for Indiana Hub and AEP-Dayton Hub. The first is observed market prices via Nodal Exchange[21]. These prices reflect the forward curve for power out through 2033. The second source for forward looking power prices relies on an internal market model constructed by IMPA utilizing the Encompass model and publicly available information regarding probable resources stacks for a given ISO. This market model is used for the Indiana Hub price forecast only. In future IRPs, IMPA intends to expand this to PJM as well. Finally, IMPA subscribes to a market price forecasting service supplied by Horizons Energy. [22] These three forward curves are blended to arrive at a final forward price expectation.

While current forward prices represent future expectations of the marginal cost of power, they tend to correlate more with forward natural gas prices rather than reflecting fundamental changes to the supply stack.

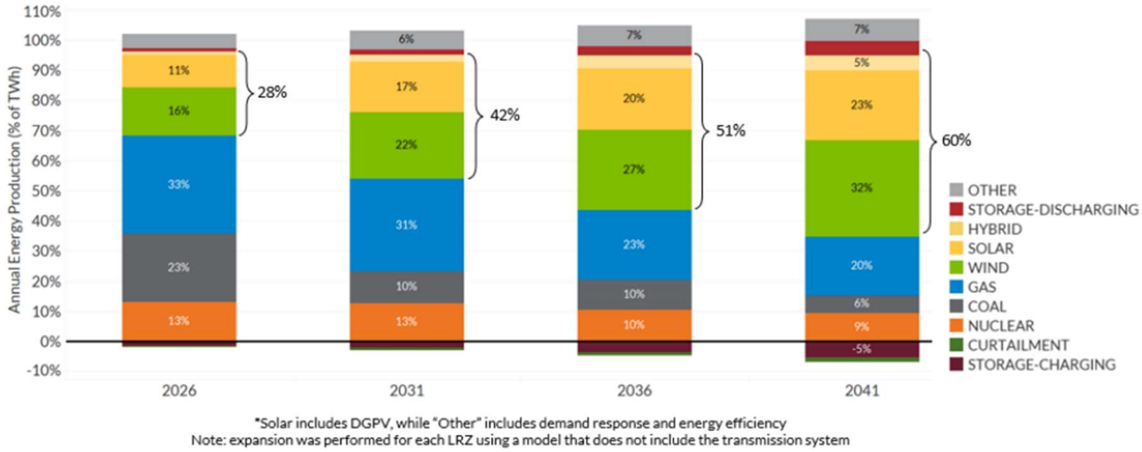
In the first step to combat this, IMPA utilized the Encompass model to build a rough approximation of the MISO North Zone and 2022 MISO Regional Resource Assessment (RRA) in order to develop a long- term forecast of future wholesale power prices.

MISO's RRA utilizes MISO member long-term resource plans to arrive at future portfolio mixes over time. While these are just a snapshot, they provide useful information on the potential future resource mix in the MISO footprint.

In Figure 25 on the following page, the expected resource mix of MISO members is expected to see intermittent resource penetration reach 60% of the system's energy production by 2041.

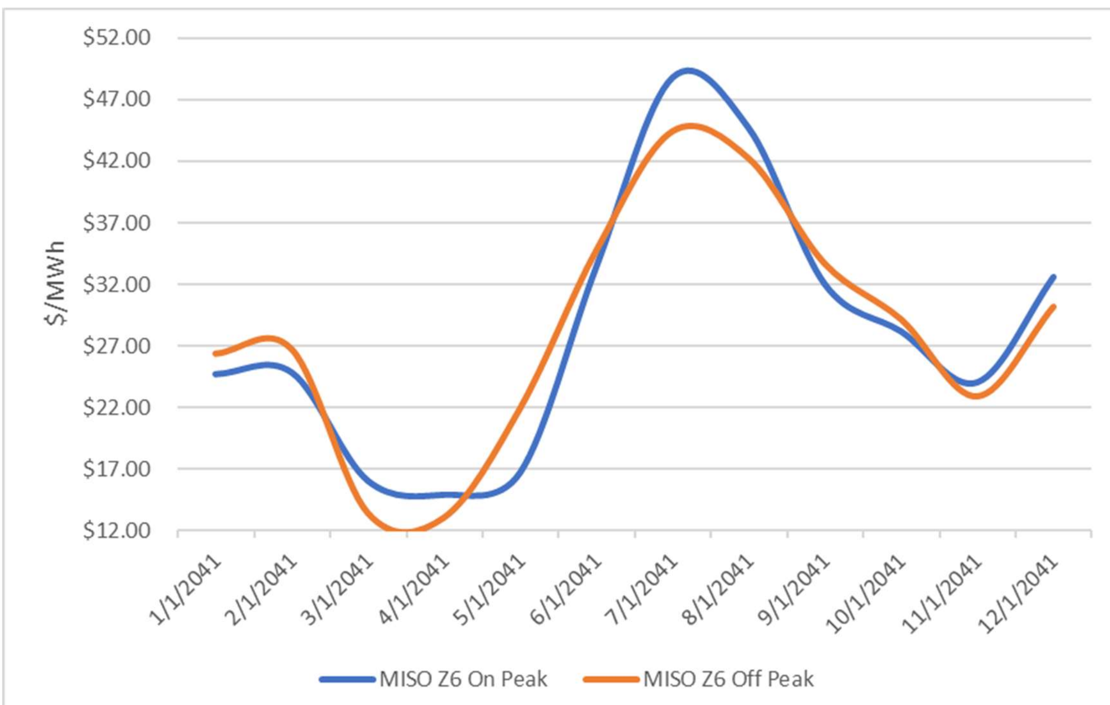
[21] https://www.nodalexchange.com/products-services/power/
[22] https://www.horizons-energy.com/

Figure 25 MISO RRA Resource Assessment Results



With 60% of market resources having zero marginal cost, the impact to wholesale prices is noticeable in the IMPA market model. Figure 26 illustrates modeled prices within the MISO Zone 6 (IN/KY) assuming the 2041 RRA resource mix above.

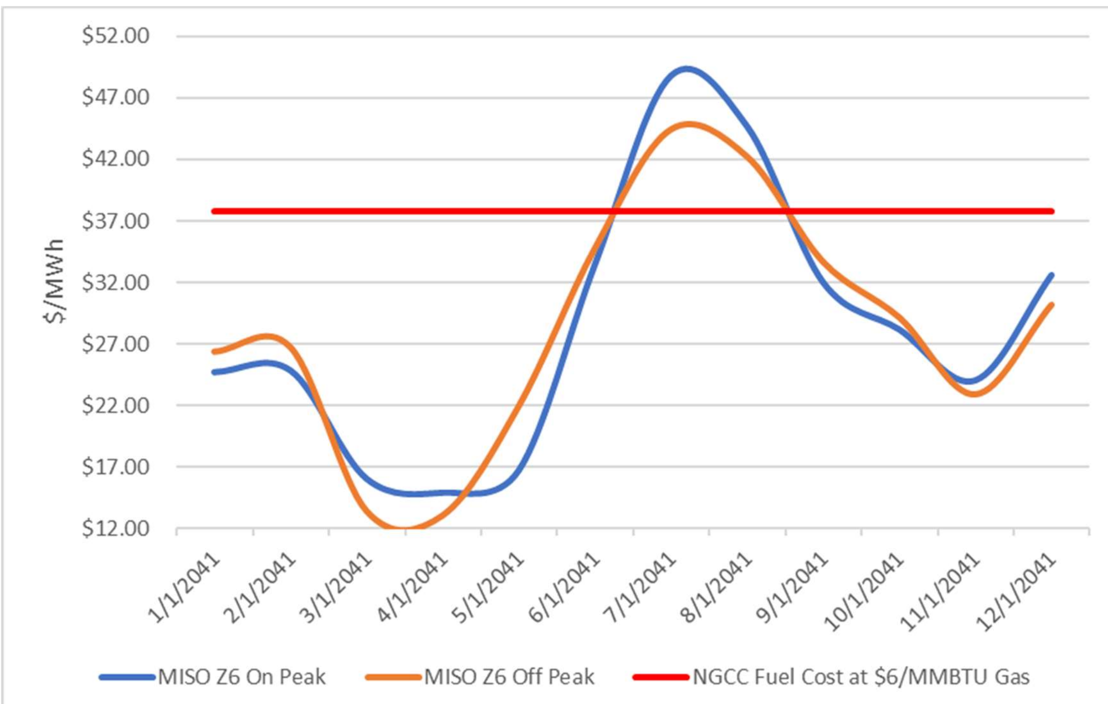
Figure 26 MISO Zone 6 (IN/KY) Modeled Prices



With roughly 30% of the footprint's generation coming from wind and relatively robust production profiles for wind during winter and shoulder months, there are times when high priced resources are required to meet periods of higher net demand (e.g. winter nights) and resulting "Off Peak" prices exceed "On Peak." Summers, however, retain their traditional relationship with "On Peak" at a premium to "Off Peak."

A larger, long-term implication of prices such as this are the risks of future stranded investment in fossil fuel generation. For example, assuming $6/MMBtu gas and a 6.3 MMBtu/MWh heat rate, a combined cycle would have a marginal fuel cost of $37.80/MWh. Those economics would place it out of the money on fuel alone for most of the year for a fixed investment that far exceeds that of a simple cycle combustion turbine.

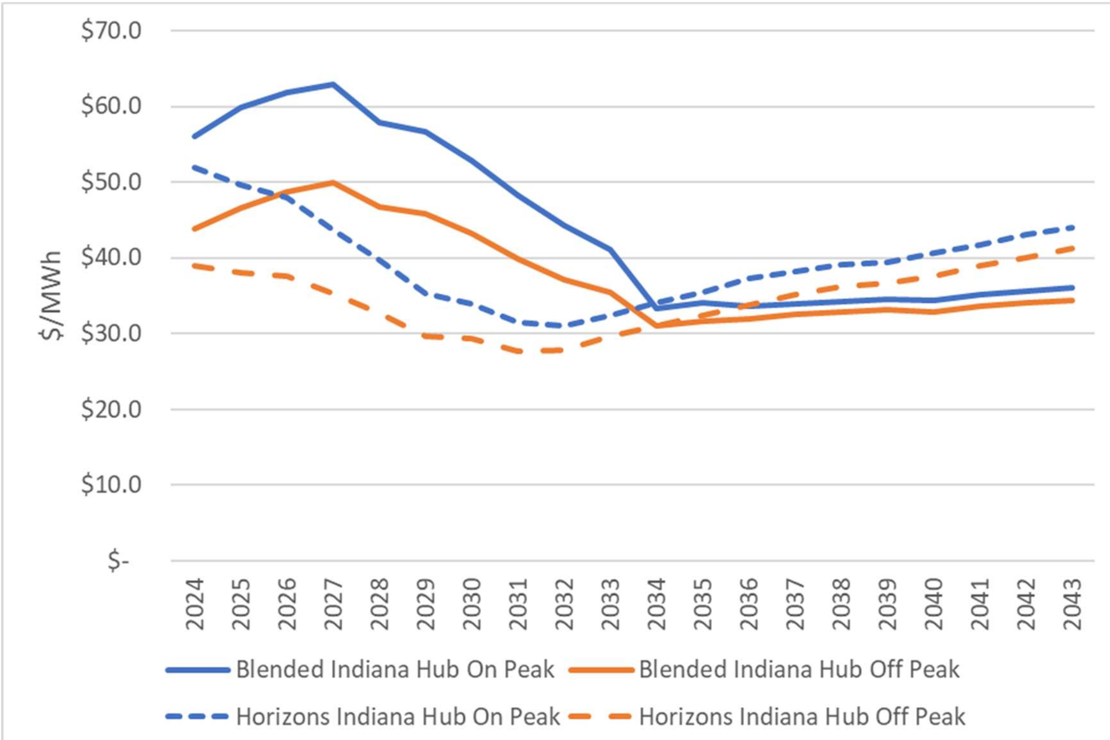
Figure 27 MISO Zone 6 (IN/KY) Modeled Prices w CC Fuel Cost



The second step in combatting a lack of information about power supply changes in the forward curve is to enlist outside help. For this, IMPA utilizes long-term power price forecasts from Horizons Energy. Horizons Energy develops market price forecasts for clients which assume a reference case, then any number of scenarios. For IMPA's Base Case, IMPA factored in Horizon's Reference case for Indiana Hub and AEP-Dayton Hub prices. As noted above, these were blended along with market forwards to make a final forward price curve.

For the sake of comparison, Figure 28 shows the Blended MISO Zone 6 forecast compared to the Horizons Indiana Hub forecast.

Figure 28 Price Forecast Comparison

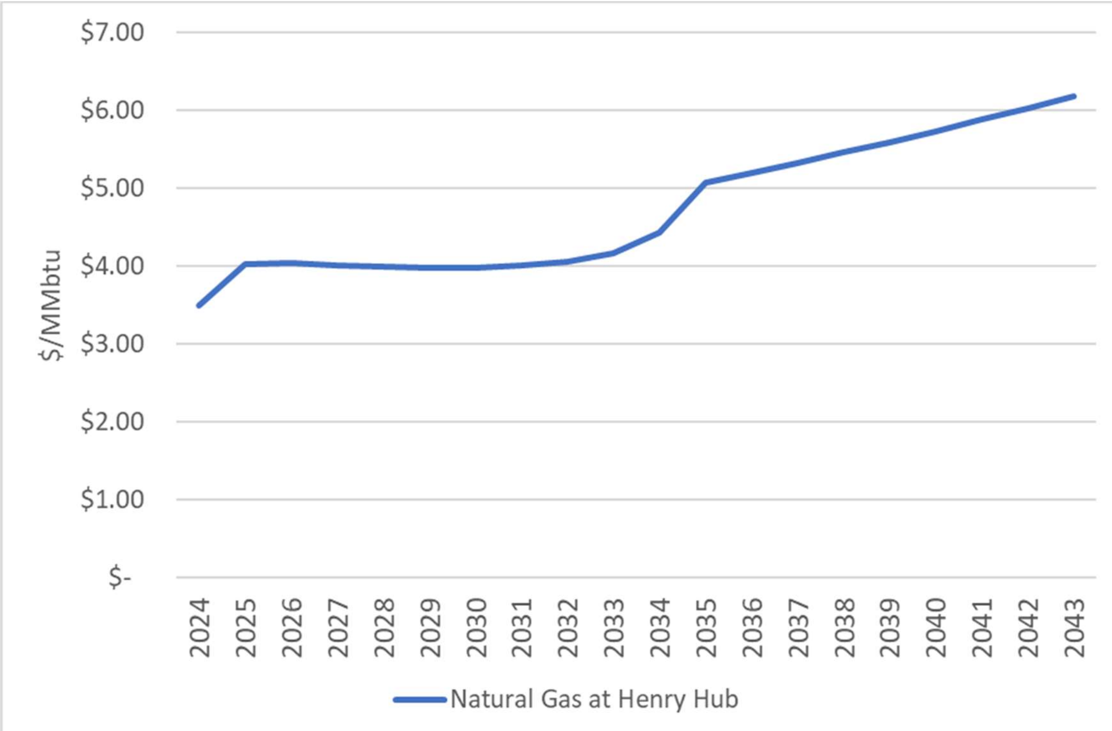


Source: *Horizons Energy Fall 2022 Advisory*

Natural gas price forecasts also play an important role in the long-term resource planning. For the 2023 IRP, IMPA handled the formulation of natural gas prices much in the same manner as was done for power prices. Market forwards were utilized, then blended with a long-term price forecast from Horizons Energy.

Current market forwards for natural gas delivered to Henry Hub end in 2033, at which point IMPA blends in Horizons forecast prices for the remaining years.

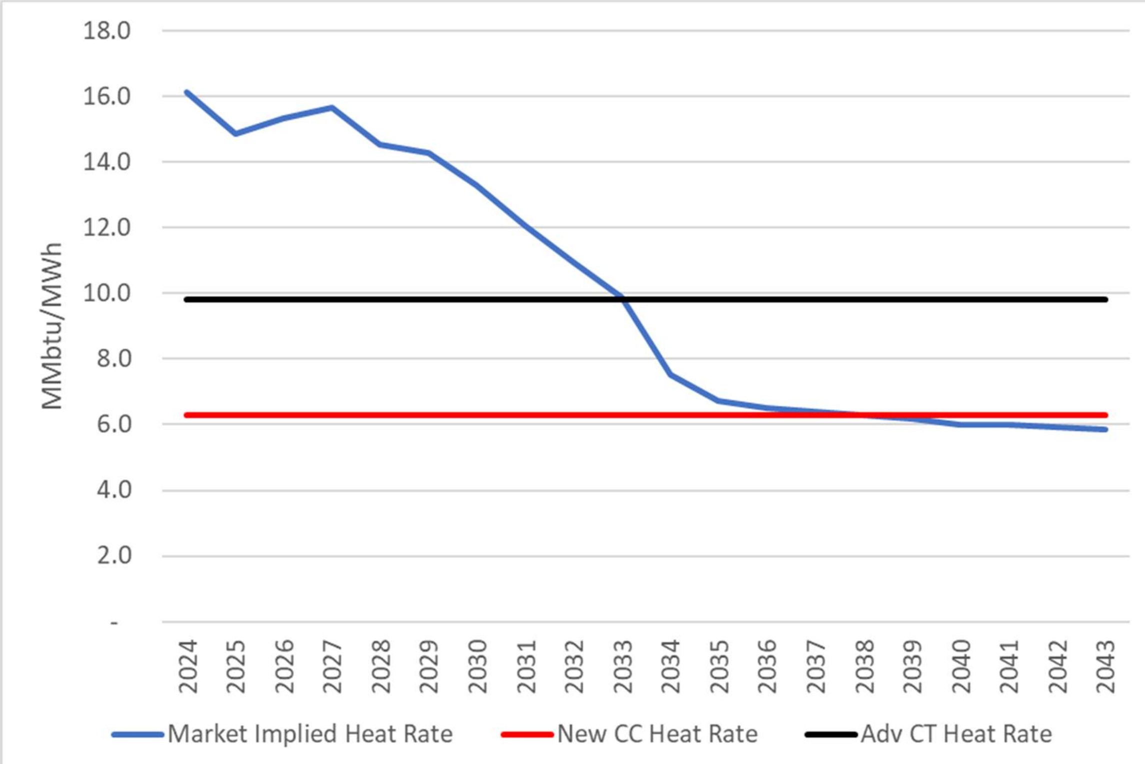
Figure 29 Annual Natural Gas Price Forecast



A combined look of power and gas markets can be made by observing market implied heat rates. Market implied heat rates are just the ratio of the On Peak power price and the fuel price that is assumed to be marginal, typically natural gas. The market implied heat rate can be used for a quick estimate of how profitable a natural gas fired unit may be under those future market prices.

IMPA's forward looking market implied heat rate suggests that with the long-term expectation of increased renewable generation, the marginal unit would become a combined cycle.

Figure 30 Long Term Market Implied Heat Rates



In the near term, market implied heat rates are favorable for both CCs and CTs, however increased renewable penetration forces the implied heat rate lower over time. By the end of the study, neither CTs nor CCs are expected to be in the money, on average. This reiterates the need to carefully weigh risk and reward when evaluating new resources.

12.7 IMPA ALL-SOURCE RFP

Given the well documented challenges in power supply procurement, IMPA opted to issue an "All Source RFP." With initial modeling suggesting a need for 200 MW of capacity, IMPA specifically requested "proposals for capacity resources that can reliably supply these 200 MW of Zonal Resources Credits during all four seasons of MISO's Planning Resource Auction." As part of this RFP, IMPA stated that while the RFP was capacity oriented, all submissions would be evaluated based on their contribution to IMPA's power supply portfolio.

IMPA received a variety of offers that can be summarized as offers sourced from existing or yet to be built thermal resources and "other" offers. "Other" offers ranged from renewable/battery storage projects to financial energy only offers. Table 19 below illustrates the offers from thermal assets.

Table 19 All Source RFP Thermal Offers

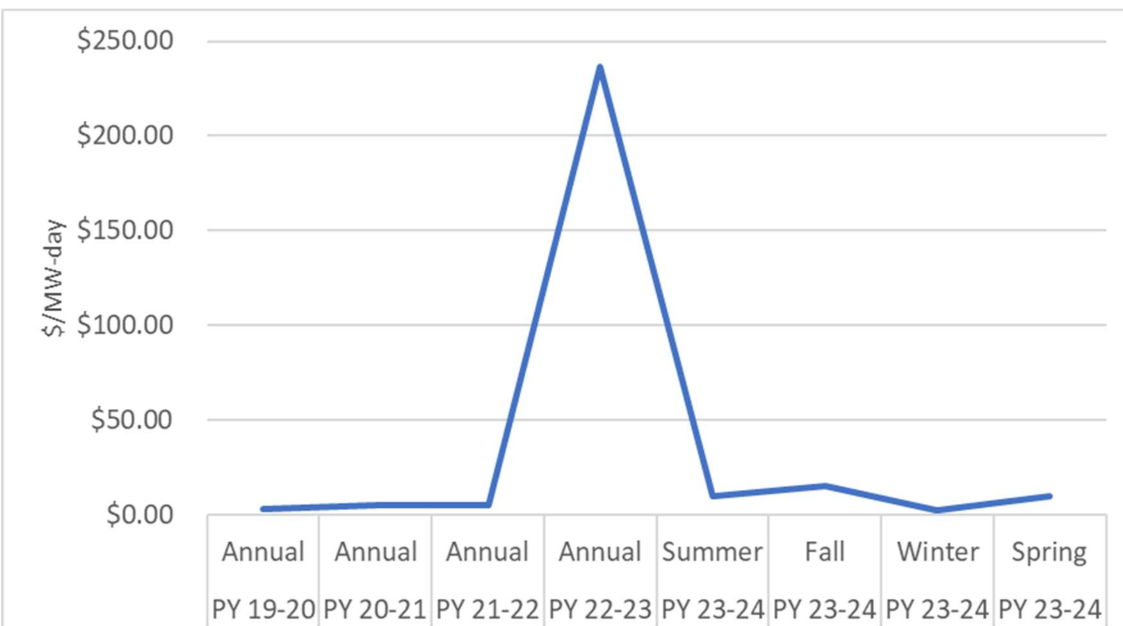
Offer Type	Term	Technology Type	RTO/Zone	Offer Size (MW)
Capacity	PY 24/25	Not Stated	MISO Zone 7 (Michigan)	25
Asset Sale	Asset Life	Natural Gas Combustion Turbine	PJM	100% to 40% of project
Capacity	PY 26/27 & PY 27/28	Coal	MISO Zone 6 (IN/KY)	Up to 200 MW
Capacity	Flexible	Natural Gas Combined Cycle	PJM	200
Capacity + Energy	18 years, starting in PY 27/28	Natural Gas Combined Cycle	MISO Zone 4 (IL)	200
Capacity	20 years, starting in PY27/28	Natural Gas Combined Cycle	MISO Zone 6 (IN/KY)	Up to 240 MW
Capacity + Energy	20 years, starting in PY27/28	Natural Gas Combined Cycle	MISO Zone 6 (IN/KY)	Up to 240 MW

These offers represent six different counterparties and reflect offers for capacity only, asset sales, and capacity and energy.

The most competitive of these offers reflect asset sales or bilateral capacity offers from resources located externally to MISO. Offers located inside of MISO were generally priced at or above the market's Cost of New Entry (CONE). In any given MISO Planning Resource Auction (PRA), IMPA's worst expected outcome under MISO's new seasonal construct is 1.75x CONE. [23] On the surface, this provision in the tariff may make offers of $230/MW-day seem attractive, however, because MISO's capacity auction is primarily a balancing auction for the prompt year, it stands to reason clearing prices will be volatile depending on market conditions for any particular year. In fact, in response to MISO's PRA clearing at CONE for Planning Year 22-23, MISO saw an uptick in external resources offering into MISO's PRA in response to these high prices. In the subsequent auction (MISO's first seasonal clearing), auction clearing prices collapsed in response to the influx of new capacity.

Figure 31 below illustrates historical clearing prices for the MISO Z6 planning resource zone.

Figure 31 MISO Zone 6 Planning Resource Auction Results



After a single year at CONE, market participants who had the ability to export capacity from areas outside of MISO moved capacity from other zones external to MISO in response to high prices, with

[23] MISO Tariff Module E-1, Section 49.0.0 PRA Procedures

the resulting Planning Year 23-24 average annual price of $9.25/MW-day. While this may not be a long-term phenomenon, it serves to illustrate the volatile nature of MISO's auction clearing.

Consequently, it seems uneconomic to "rent" capacity in the bi-lateral market at prices near the market price cap. Despite this, IMPA included these offers as selectable resources in the Encompass model, along with the other offers listed above.

The second batch of offers generally reflect energy only offers, renewable offers, and hybrid offers. These are shown in Table 20.

Table 20 All Source RFP Other Offers

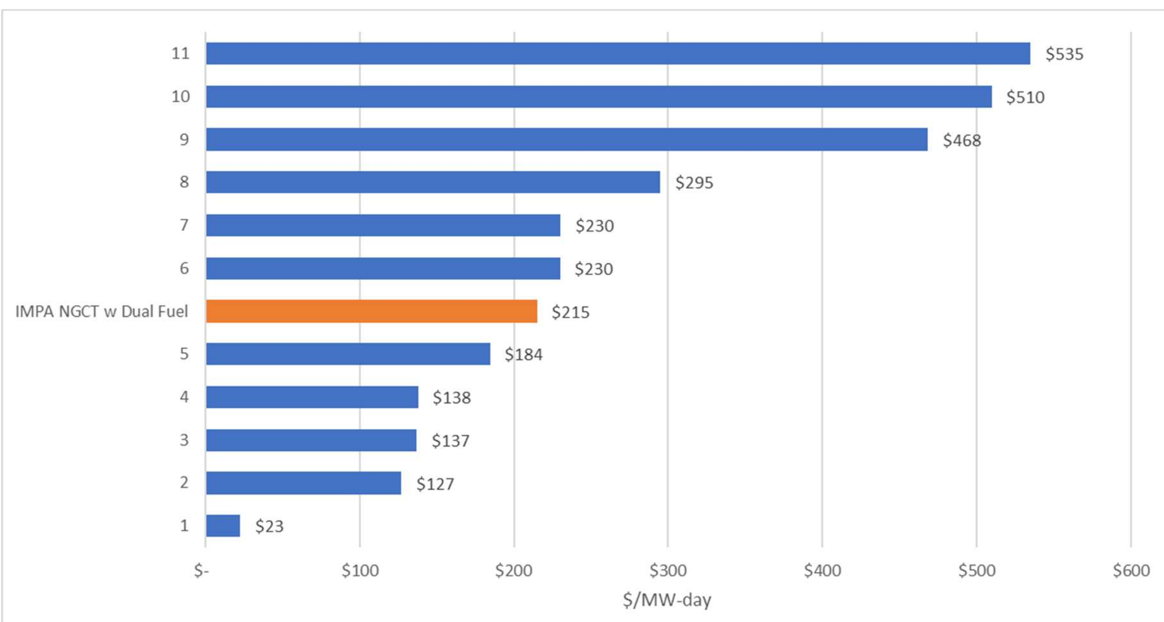
Offer Type	Term	Technology	Point of Delivery	Offer Size (MW)
Capacity	20 years	Busbar	Various	5-20
Energy + Capacity+RECs	Up to 35 years	Solar	Busbar	199
Energy + Capacity+RECs	25 years	Solar	Busbar	125
7x24 Energy	Cal 24-25	Financial	Indiana Hub	100
7x24 Energy	Cal 24-26	Financial	Indiana Hub	100
Fixed Load Shape	Either Cal 24-25 or Cal 24-26	Financial	Indiana Hub	Variable, floats with proposed load shape
Call options	Various	Financial	Indiana Hub	100
Energy + Capacity	30 Years	Solar + Storage	Busbar	100
Capacity Only	10-20 Years	Solar	MISO Zone 6 (IN/KY)	200
Capacity + Energy	20 years	Storage	MISO Zone 6 (IN/KY)	200

The most notable capacity prices shown are for battery storage or hybrid projects (solar + storage). Two competitive offers for storage were received, with the first being a portfolio of behind the meter battery projects at IMPA member locations, and the second being capacity from currently operational solar projects. Regarding the first storage response, it assumes that IMPA supplies the sites and covers interconnection cost at each of these sites. It also assumed that IMPA would only receive the capacity credit for the installations and none of the market benefit (which would be small for behind the meter generation). The second response of capacity only from operational solar is compelling but fails to address IMPA's requirement of being able to deliver 200 MW of Zonal Resource Credits for all four seasons given solar accreditation under MISO rules. Solar's capacity accreditation for 200 MW of solar would equate to roughly 2 MW under MISO's current rules, and to fill the remainder of the position IMPA would need to procure an additional 198 MW of ZRCs to hedge the remaining requirement.

IMPA received zero responses from wind resources, which, in previous modeling efforts have shown to be a good complement to IMPA's existing resource portfolio in previous modeling efforts.

Finally, IMPA received price estimates from General Electric for gas turbines in three different sizes, along with consulting estimates from Black and Veatch for balance of plant costs. The estimated cost for these units for IMPA to construct was approximately $215/MW-day. The figure below shows the masked offers along with the IMPA estimated cost to build a combustion turbine.

Figure 32 All Source RFP and IMPA Self Build CT Option - Equivalent Capacity Cost

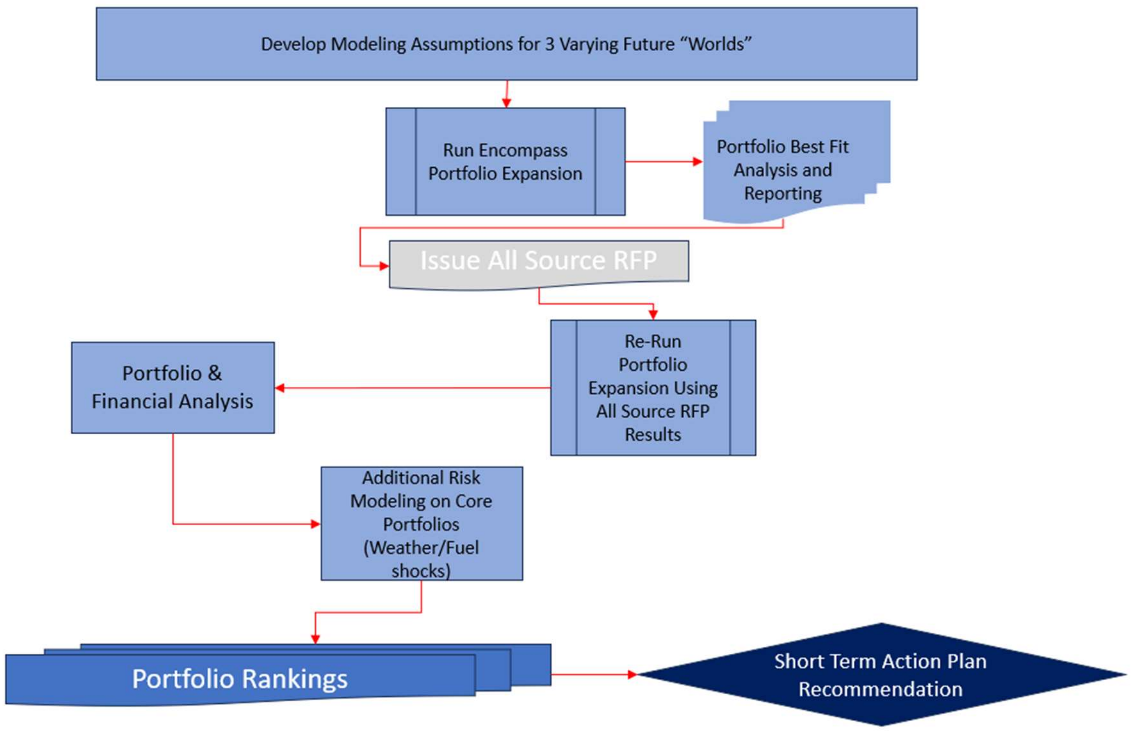


Baseline installed costs for GE combustion turbines ranged from $714/kw to $1105/kw. IMPA further assumed another $29/kw for incremental transmission upgrade costs and anywhere from $96/kw to $255/kw for the addition of hot Selective Catalytic Reduction.

Additional risk stems from future accreditation risk of solar resources at the ISO/RTO level. Potential, future erosion in capacity accreditation would serve to exacerbate this situation.

12.8 Portfolio Selection

Figure 33 IRP Flowchart

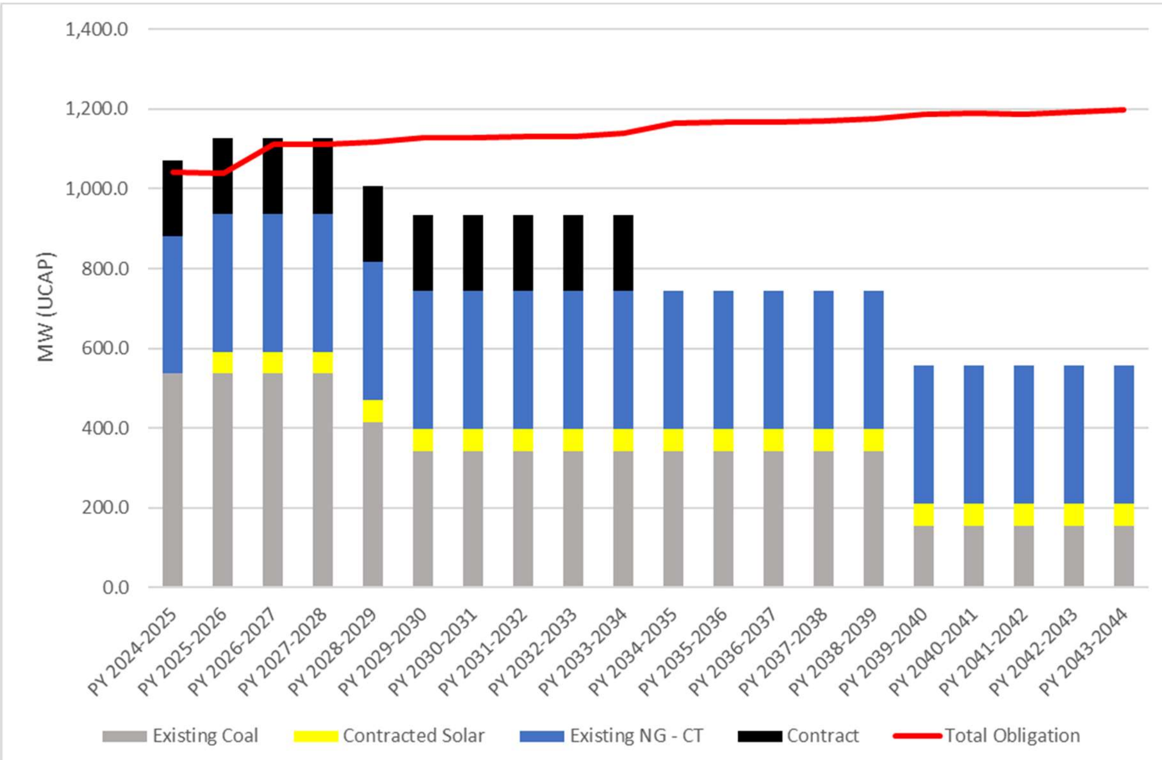


With the base case assumptions established, the next step is to allow Encompass to optimize the IMPA portfolio under those scenario assumptions.

As a refresher, IMPA has load in two markets, with roughly 2/3 of that load located in the MISO market and the balance in the PJM market. Due to various rule differences between the two RTOs, IMPA plans for each of these areas separately and views the two loads effectively as two separate portfolios. Planning activities revolve around the two primary products, energy and capacity, in each market. The following summarizes IMPA's capacity position on an overall market basis.

With the MISO market having moved to a four-season capacity market and PJM currently contemplating a two-season construct, IMPA's aggregate capacity position is shown for the Summer and Winter in Figures 34 and 35 below.

Figure 34 IMPA Mid Optimization Portfolio - Base Case - Summer



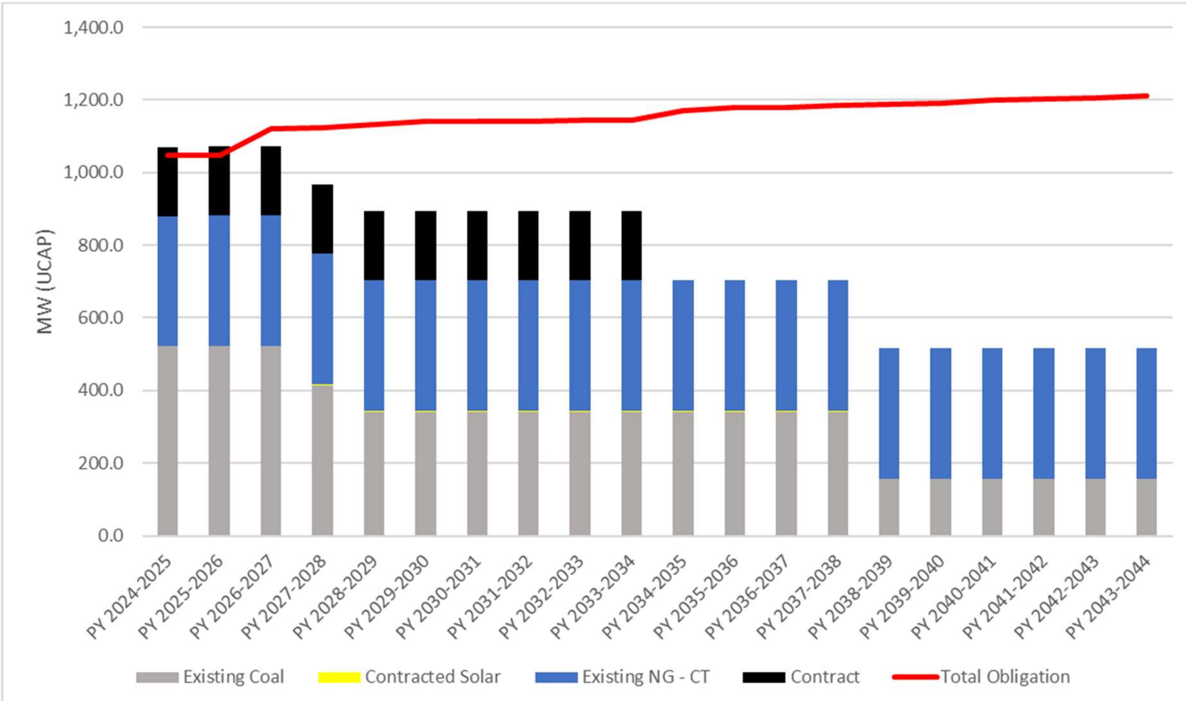
IMPA's overall summer capacity position is expected to be flat until Planning Year 28-29. In the base case this is largely driven by allowing Gibson 5 to retire economically in Encompass. This represents a slight extension in life from the previously assumed retirement of Planning Year 26-27. **After modeling efforts had concluded, the joint owners of Gibson 5 elected to keep Gibson 5 in service until Planning Year 30-31.**

The shift up in the load obligation in Planning Year 26-27 reflects the expiration of a bilateral full requirements transaction (FRT). These two key milestones occur in IMPA's MISO portfolio.

Beyond the Planning Year 26-27 planning horizon, the next major milestones are the retirement of WWVS in Planning Year 28-29 and the expiration of a baseload contract in Planning Year 33-34. These milestones occur in the PJM portion of IMPA's portfolio.

Finally, with Illinois' Climate and Equitable Jobs Act (CEJA), Prairie State Units 1 & 2 are retired in the model effective January 1st, 2039.

Figure 35 IMPA Mid Optimization Portfolio - Base Case - Winter



IMPA's winter capacity position is slightly worse, due to very little capacity accreditation for solar in MISO's winter season, with the Ratts Solar project (150 MW ICAP), going from 55.5 MW of capacity credit in the MISO summer season, to a mere 1.5 MW in the winter season.

Figure 36 and 37, on the following page, illustrates the optimized portfolio for the winter and summer planning periods with the resource additions.

Figure 36 Base Case Expansion Plan Summer

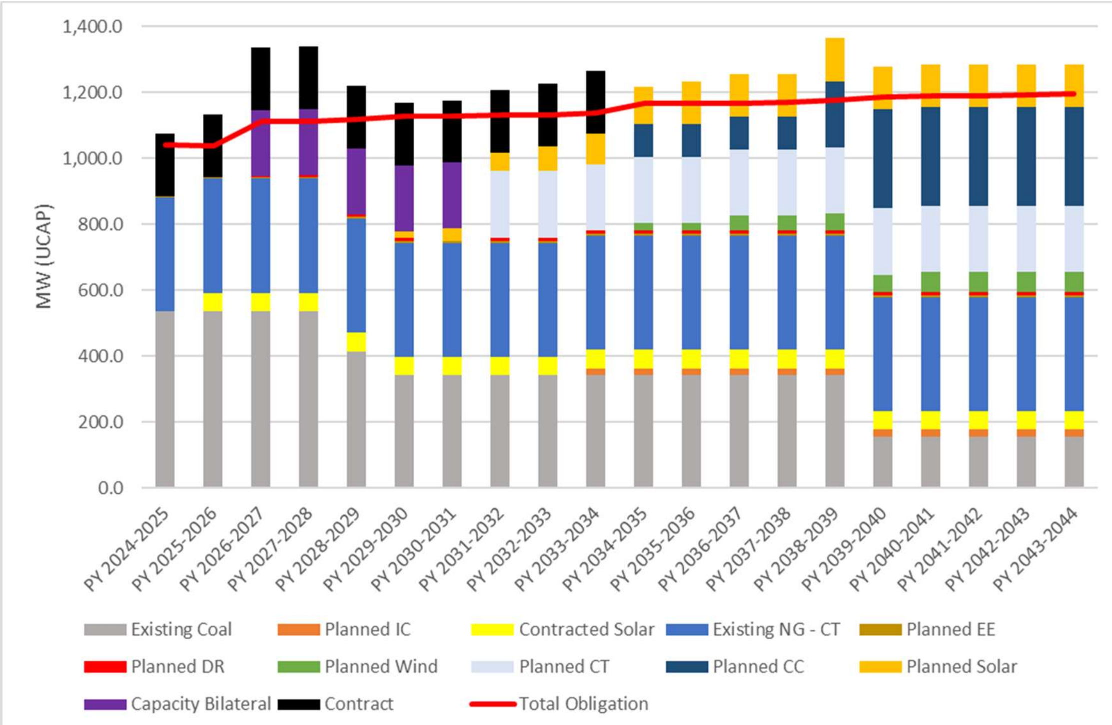


Figure 37 Base Case Expansion Plan Winter

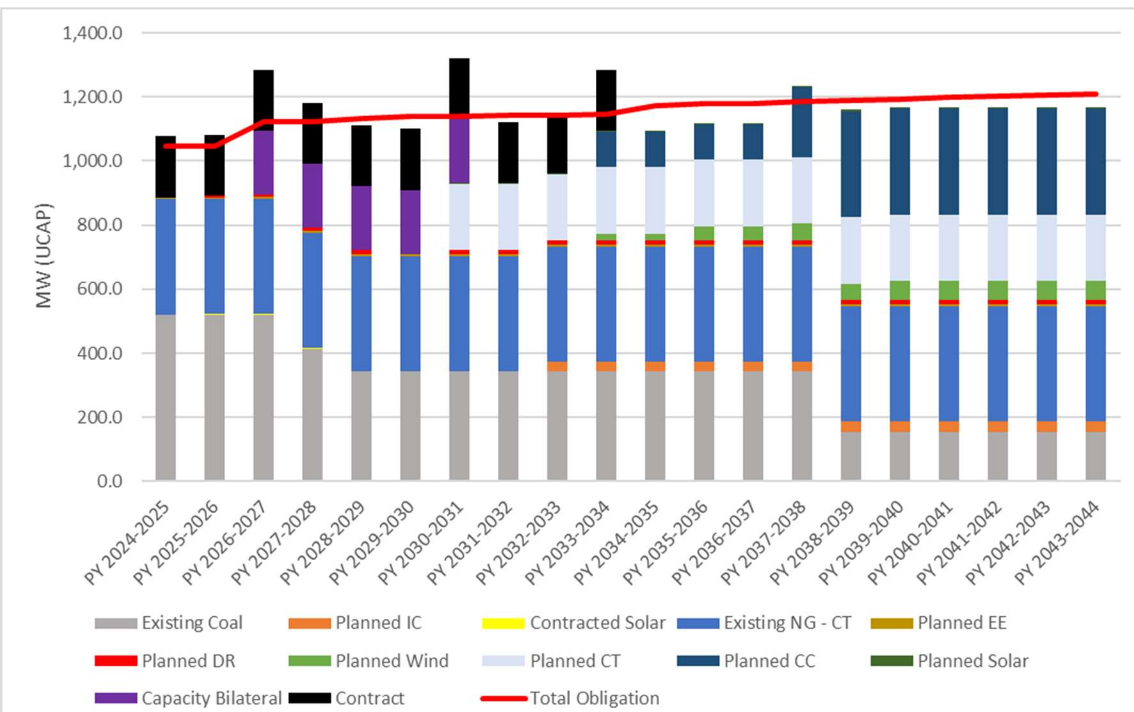
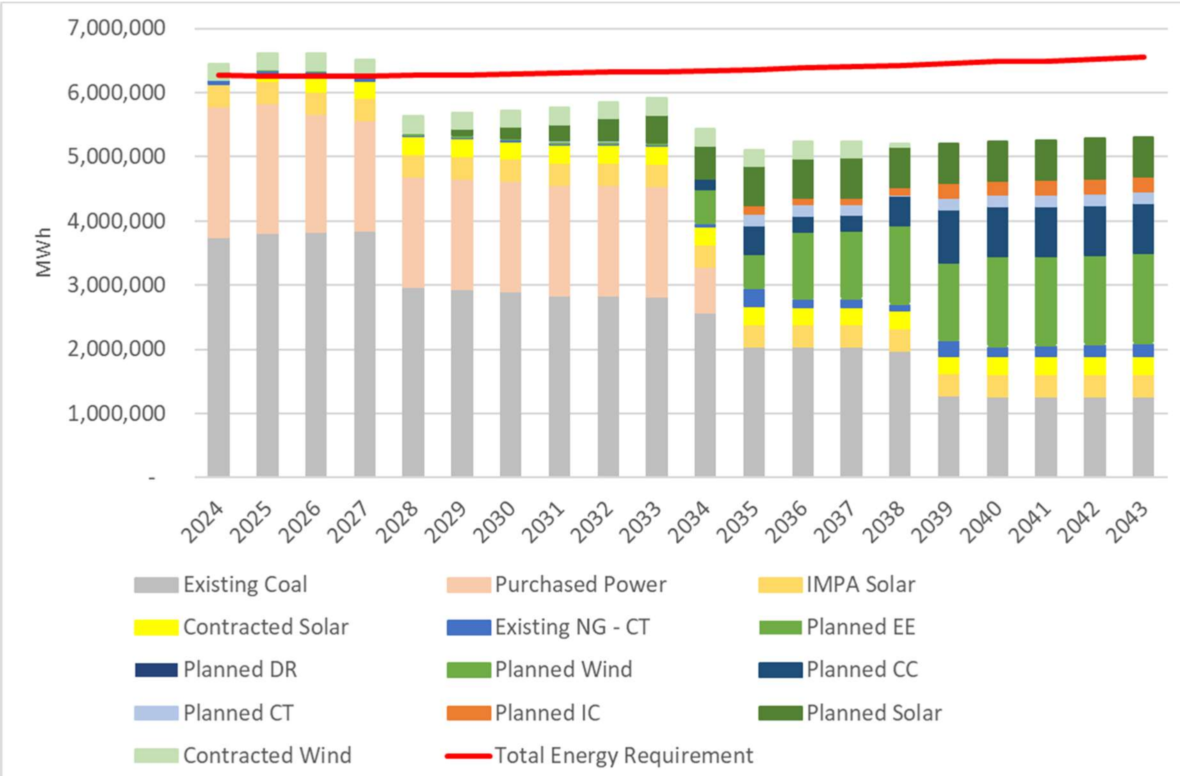


Figure 38, below, illustrates the annual energy position of the optimized portfolio over the study horizon. It should be noted that the open energy position relative to the energy requirements reflects the model utilizing economic spot market purchases vs. uneconomic gas generation from the combined cycles that were added to the portfolio.

Figure 38 Annual Energy Position



12.8.1 MISO Portfolio Discussion

An overview of the near to intermediate term portfolio milestones in the MISO portfolio are shown below in Table 21. Only the first 10 years are discussed as other major milestones are well outside the planning horizon and largely uncertain at this time (e.g., PSGC/CEJA compliance). Note that the position table only accounts for the incremental capacity additions/retirements and is not a full accounting of the position.

Table 21 MISO Major Portfolio Milestones

Near to Intermediate Term Milestones - IMPA MISO Portfolio Base Case						
Date	**Resource**	**+/- MW (ICAP)**	**+/- MW (Summer UCAP)**	**+/- MW (Winter UCAP)**	**Summer Position Long/(Short)**	**Winter Position Long/(Short)**
PY 24/25					(85)	(114)
Jul 2025	Ratts Solar	150	55	2	(24)	(109)
May 2026	Existing Bilateral Capacity	(75)	(75)	(75)	(99)	(184)
Jun 2026	New Bilateral Capacity - 5 yr Term	200	200	200	101	17
Jan 2028	Gibson 5 Retirement	(156)	(121)	(106)	(20)	(89)
Jan 2029	Solar PPA	50	19	1	(2)	(89)
Jan 2031	IMPA Self Build CT COD	239	201	208	199	119
May 2031	New Bilateral Capacity - 5 Yr Term	(200)	(200)	(200)	(1)	(81)

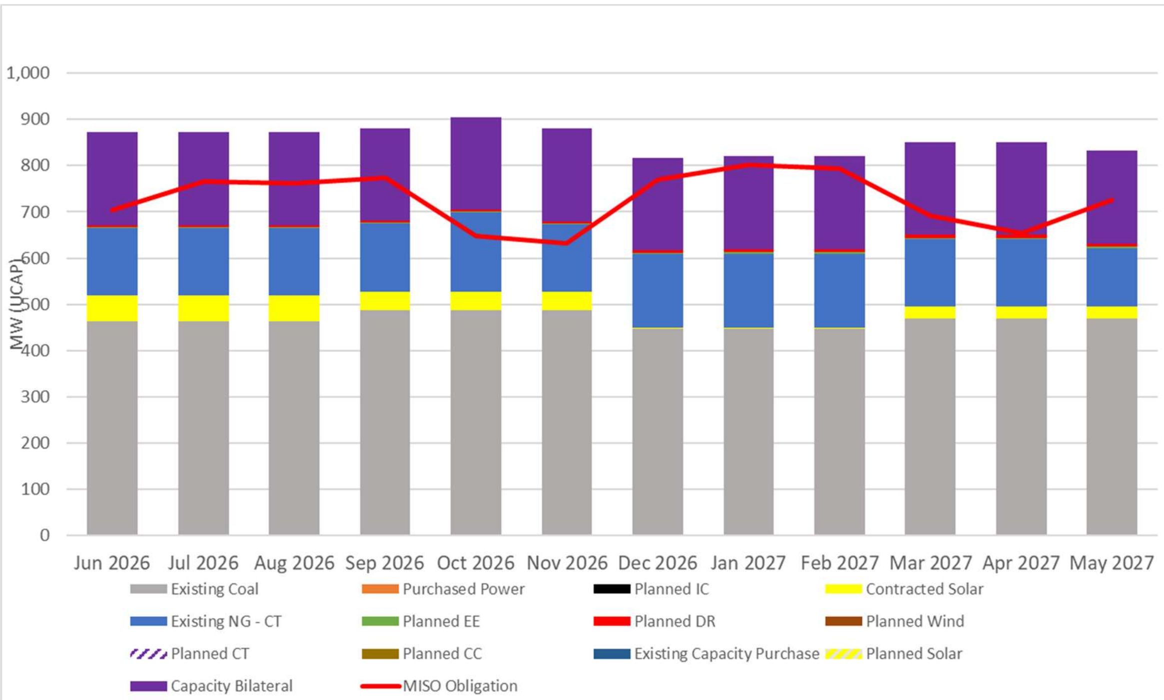
As part of IMPA's previous planning efforts, a 150 MW solar PPA was initially signed by IMPA and the developer in 2020 for off-take from the Ratts Solar project. After three amendments in roughly three years, that PPA has been executed with new, mutually agreeable terms to both IMPA and the developer. This project is expected to go commercial in the summer of 2025.

In Planning Year 26-27, IMPA will have a 75 MW bilateral capacity hedge expire. Using the available pool of All Source RFP responses, as well as "generic" renewable resources modeled as PPAs, the next capacity addition selected in the Encompass optimization was a five-year Bilateral Capacity offer. At 200 MW offered, this makes IMPA somewhat long but only until an economic retirement of Gibson 5 in January of 2028. In January of 2029 the model selects a generic Solar PPA primarily for energy needs.

Finally, the model selected an IMPA constructed GE Frame 7F.05 in January of 2031, just prior to the expiration of the bilateral capacity that was procured for June 2026.
Also, worth noting but not illustrated in Table 21 above are incremental EE and demand response deployments totaling 10.6 MW.

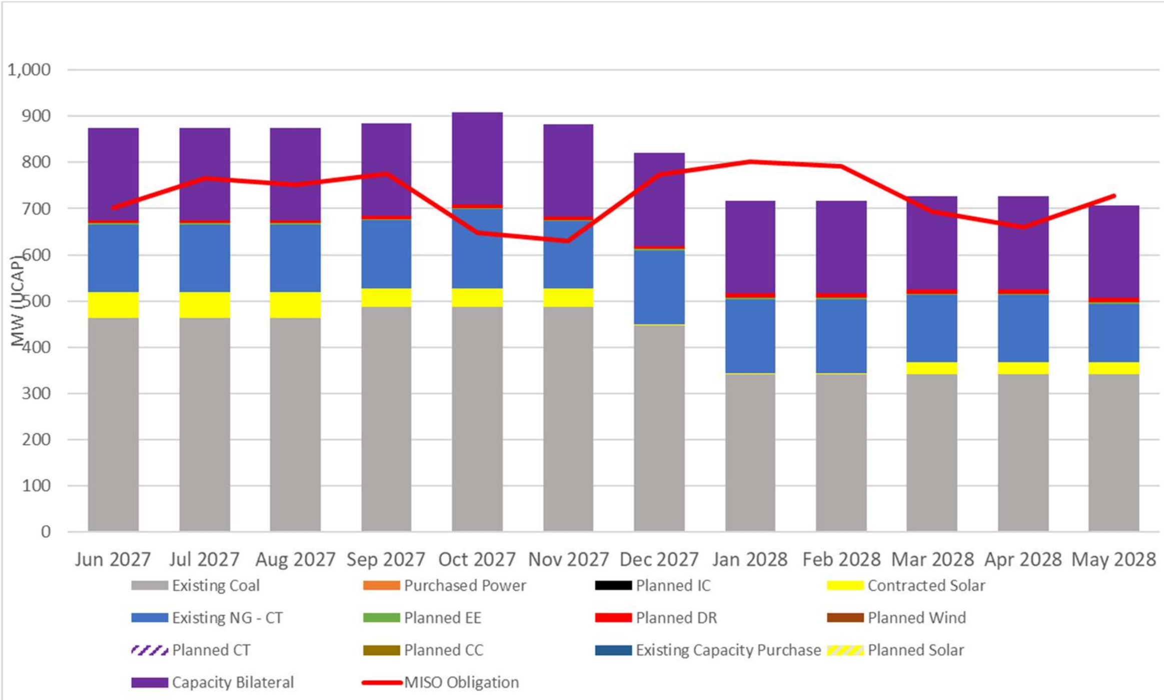
While this results in a "lumpy" capacity position, it does reflect real life realities when capacity planning and underscores the importance of what can be accomplished in theory versus reality. With the 200 MW bilateral capacity in place, along with a planned Demand Response program, IMPA would be somewhat long capacity in the first planning year of its procurement, but notably flat (assuming no changes to MISO PRM requirements), for the winter.

Figure 39 MISO Capacity Position Planning Year 26-27



As previously noted, Gibson had been slated to retire in previous IRPs during Planning Year 26-27. However, for this IRP, IMPA has allowed Gibson to retire economically while the joint owners (Duke, WVPA, and IMPA) evaluate life extension strategies. Using very preliminary capital expenditure estimates, Gibson was retired in the model in January of 2028.

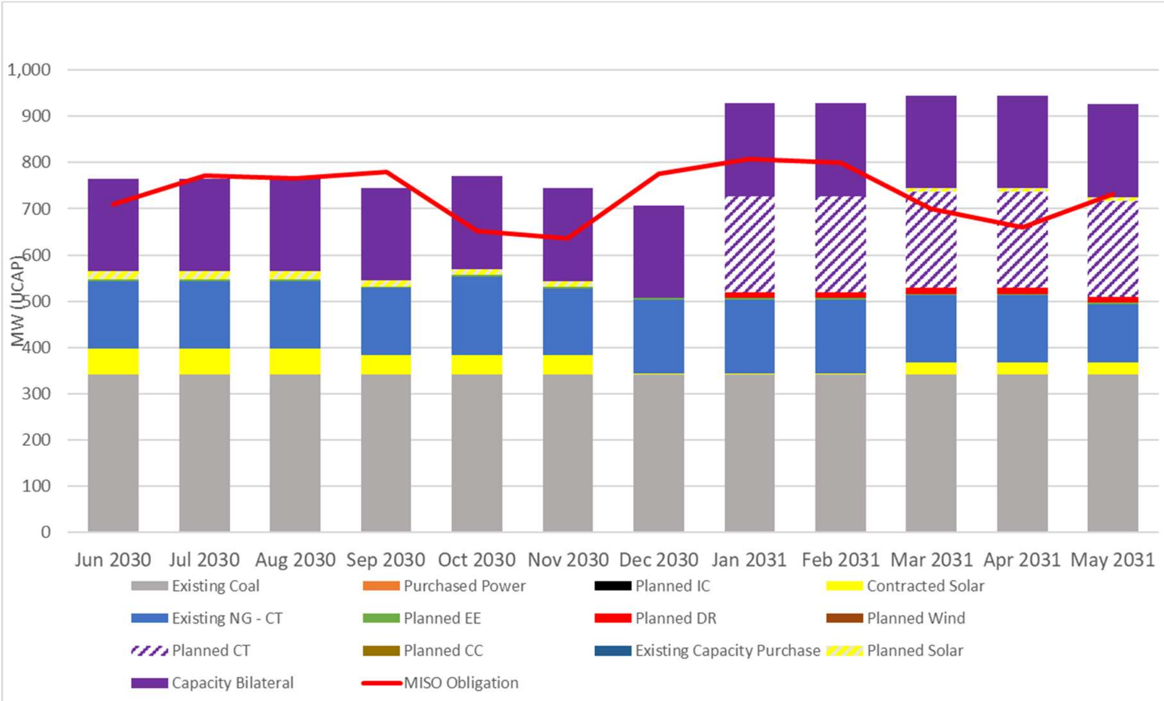
Figure 40 MISO Capacity Position Planning Year 27-28



By having the bilateral capacity purchase in place, IMPA has an effective hedge for the eventual retirement of Gibson 5. With Gibson 5 retiring in January of 2028, IMPA would still be short for the winter season of Planning Year 27-28.

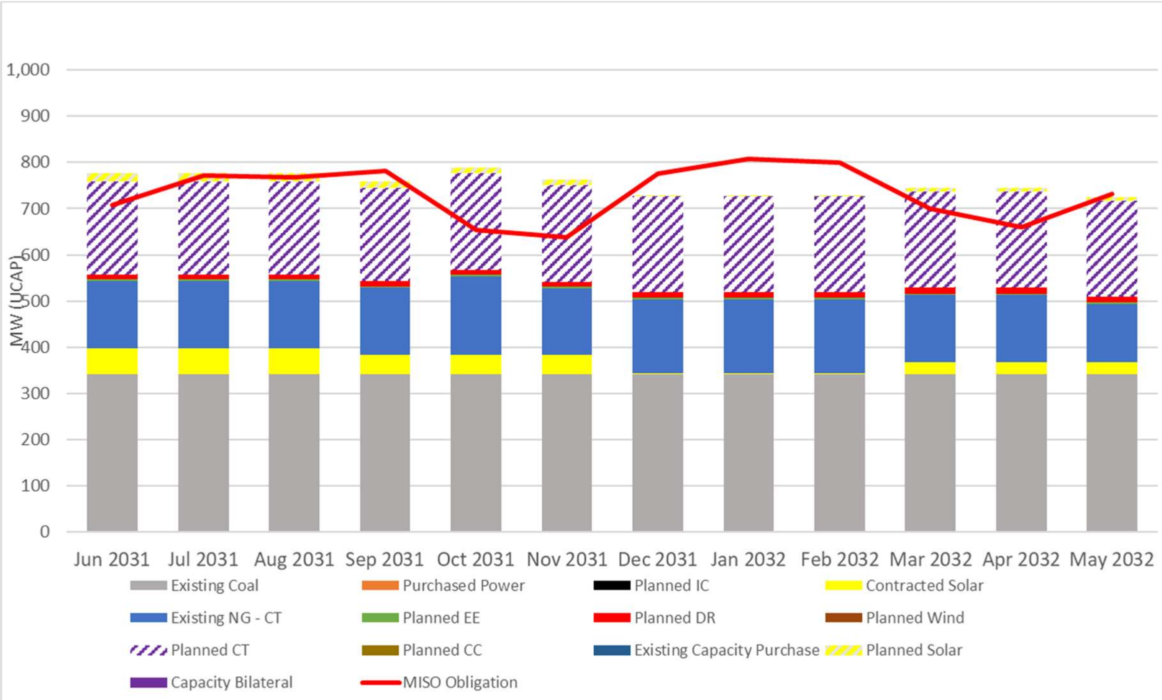
The next milestone year occurs during Planning Year 30-31 when a GE Frame 7F.05 is added while the bilateral capacity contract is still in place. This makes IMPA's MISO portfolio long capacity for the last five months of the planning year, but would provide schedule contingency if the development of new resources experiences trouble with the interconnection queue or other delays. In addition, it would serve as a hedge against potential future degradation in accreditation from IMPA's existing resources or increases in reserve margins.

Figure 41 MISO Capacity Position Planning Year 30-31



However, this bilateral capacity purchase that was chosen in the Encompass optimization, expires in May of 2031, helping to flatten the capacity position.

Figure 42 MISO Capacity Position Planning Year 31-32



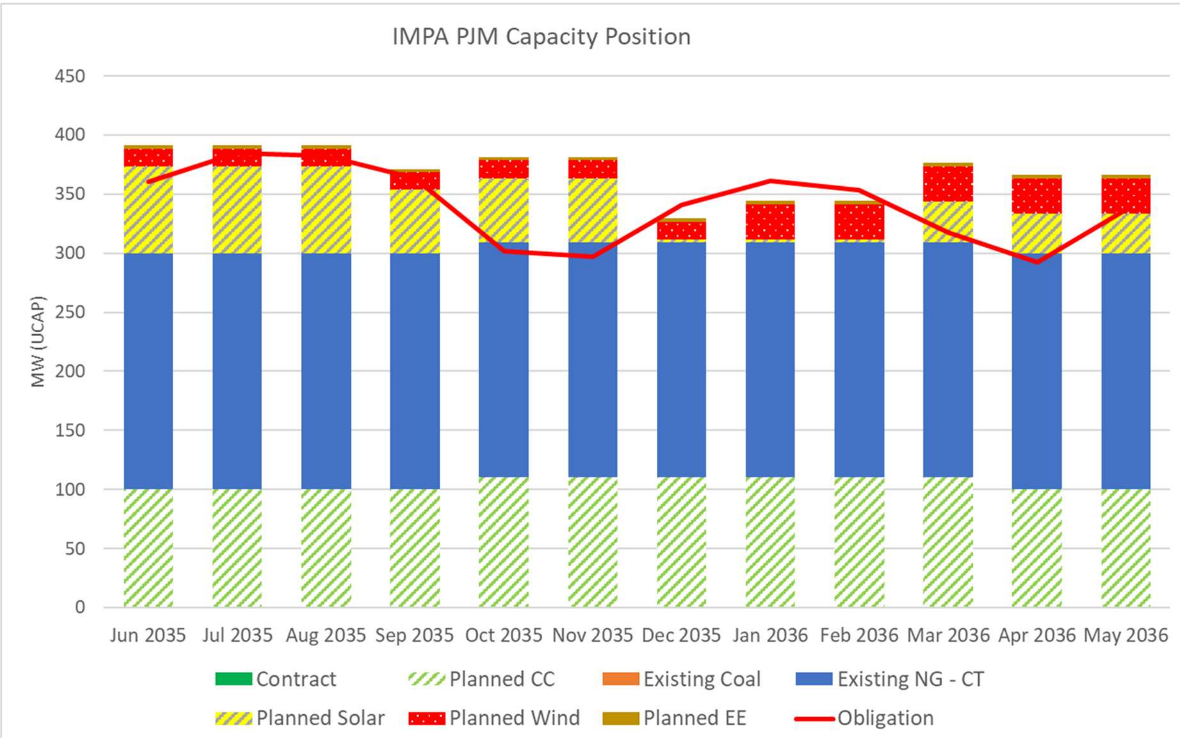
With the addition of the CT, IMPA still has a modestly short winter position. While the MISO seasonal construct has hampered the market for bilateral capacity in the near term, IMPA is comfortable leaving this position open as the MISO market continues to evolve.

Longer term, the MISO portfolio is expected to see the retirement of PSGC in 2039 due to Illinois' Climate and Equitable Jobs Act (CEJA). This capacity is ultimately replaced with 200 MW of natural gas combined cycle.

12.8.2 PJM Portfolio Discussion

IMPA's PJM portfolio is currently long capacity relative to its requirement and is expected to be so even after the retirement of Whitewater Valley Station in 2028. The largest planning need for the PJM portfolio is after the current full requirements contract with AEP expires in Planning Year 34-35. Due to the long time horizon, IMPA did not do an All Source RFP for PJM capacity or energy.

Figure 43 PJM Capacity Position Planning Year 35-36



This is not a large departure from previous IRPs, with the optimized solution involving a diverse supply of wind, solar, and natural gas to replace the AEP agreement. This expansion remains relatively static, save some incremental additions of wind PPAs.

12.9 Risk Assessment

Process

In previous IRPs, IMPA utilized stochastic analysis to gauge risk profiles of candidate portfolios. The advantage to utilizing stochastic analysis is that it captures the impact of cross commodity correlation on rates and revenue requirements. However, when evaluating portfolio risk it sometimes yields little informational value. For example, across portfolios constructed in “high”, “low,” and “expected” load and price regimes, stochastic outputs tend to just create parallel shifts in rate outcomes, especially when evaluating metrics at a 95th percentile threshold.

For this IRP, IMPA opted to evaluate portfolios based on their robustness to previously seen “risk” events. IMPA selected two notable winter events, winter storms Uri and Elliot, as well as recent summer “maximum generation” events seen in the summer of 2022 and 2023. While Uri was more concentrated to the nation’s southwest, its vast size stressed grid conditions considerably, while Elliot more directly impacted Indiana. The summer maximum generation events encompass those declared by MISO during July of 2022 and August of 2023.

IMPA compiled historical loads, prices, and generator performance during each of these events and applied adjustment factors to the forecasted loads, prices, and generator capacity for those events.

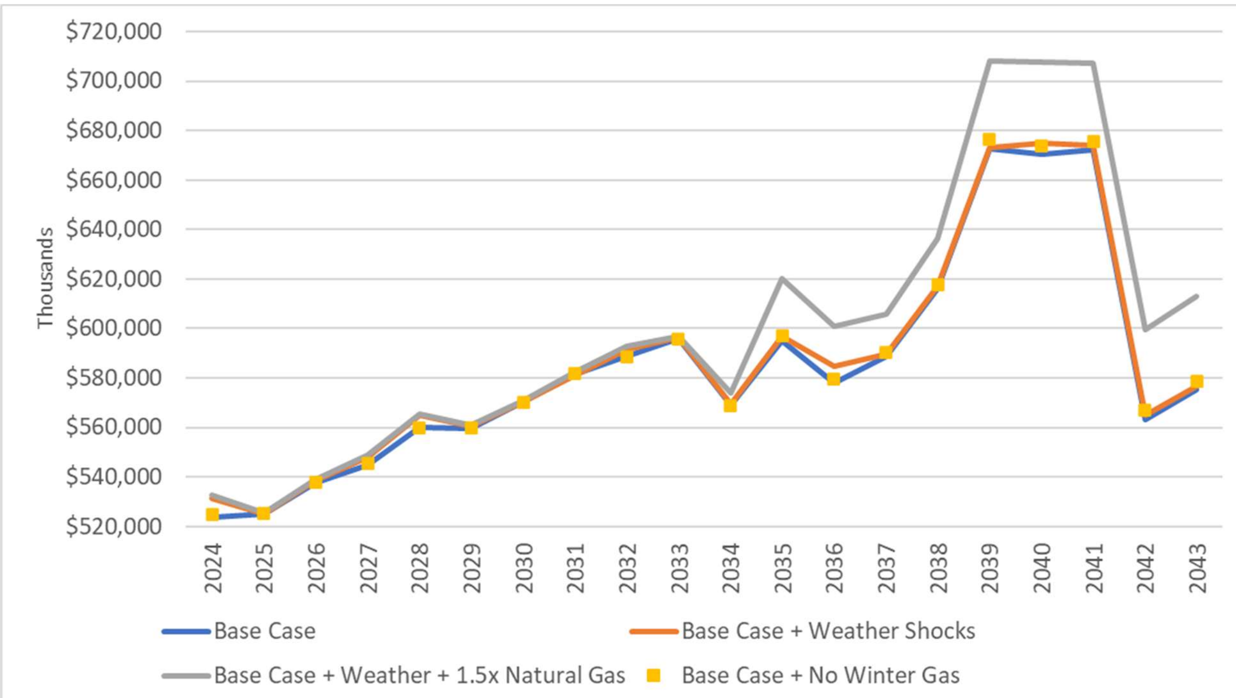
Winter Storm events were assumed to alternate every four years, with Elliot like events occurring on even years starting in 2024 and Uri like events occurring on odd years beginning in 2027. Summer events were assumed to occur every summer for the entire planning horizon.

As an additional shock, the portfolios were stressed further by applying at 1.5x multiplier on natural gas prices in addition to weather related stressors. Also, a sensitivity was run assuming no access to natural gas during the winter months.

Results

Overall, the Base Case shows resilience in the face of weather and fuel shocks from 2024 to 2034, as measured by the annual revenue requirement. In 2035, the weather shock, when combined with a 1.5x shock to natural gas prices, however, sees a 4% increase in revenue requirements in 2035 over the base case, growing to a 7% increase by 2043. Overall, this amounts to a $128 million dollar impact to the net present value of revenue requirements (NPVRR) between the worst risk case and the base case.

Figure 44 Annual NPVRR Between Cases



2035 sees a large jump in revenue requirement due to a number of factors. First, 2035 is assumed to have a Winter Storm Uri type of event. While not as dire as a Winter Storm Elliot, it does make for load deviations as high as 11% over forecasted loads. Second, the AEP contract is replaced with a natural gas combined cycle, increasing natural gas exposure in the portfolio. Third, the modeled 2035 phase in of the CEJA imposed CO2 constraint on PSGC begins to limit the ability of PSGC to meet the increased demand in a higher market price environment. This in turn places additional strain on IMPA's natural gas fleet, which faces higher operating costs via the 1.5x multiplier on natural gas. However, the fossil fuel fleet is backstopped with additions of wind and solar, which help insulate the portfolio from impacts to increases in load and natural gas prices, to the extent they are available.

Table 22 NPVRR and Rate Impact Comparisons

Case/Sensitivity	20 Year NPVRR	20 Year Levelized Rate	10 Year NPVRR	10 Year Levelized Rate
Base Case	$6,581	$91.53	$4,083	$89.24
Base Case w No Winter Gas	$6,593	$91.69	$4,085	$89.29
Weather Shock	$6,607	$91.88	$4,099	$89.60
Weather Shock + 1.5X Gas	$6,709	$93.31	$4,105	$89.73

As shown in Table 22, the biggest risks to the base case portfolio are a combination of weather driven events and shocks to natural gas prices. Financially, disruptions to natural gas supply are not impactful under normal conditions as lost CT runs (which are modeled to be capped at a 10% NCF), are re-allocated to summer months. Effectively the net impact is the difference between higher purchased power costs in the winter months netted against incrementally higher CT revenue in the summer.

Weather shocks when coupled with surges in natural gas prices are far more impactful as the portfolio becomes more stretched in later years from the PSGC carbon constraint and higher fuel costs for IMPA's combustion turbine fleet.

While weather risks can be difficult to hedge, risks arising from fuel shocks or disruptions can be hedged by natural gas hedging, firm gas agreements, or utilizing on-site/dual fuel capability for periods of extreme duress. Notably, IMPA's CAPEX assumptions for natural gas combustion turbines assume dual fuel capability.

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13 VOLUNTARY NET ZERO CO2 BY 2040

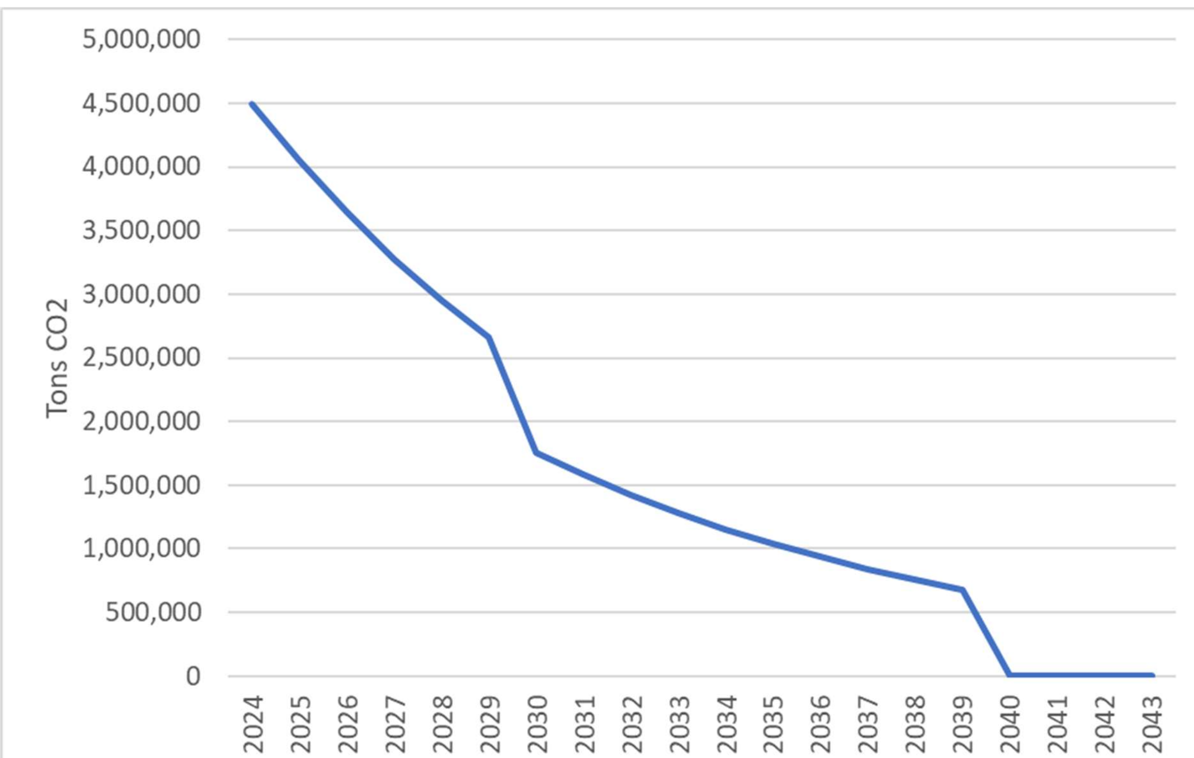
13.1 IRP SCENARIO DEVELOPMENT

This section sets the groundwork for the assumptions used to construct the Voluntary Net Zero Case, albeit in a somewhat more condensed layout than was used for the base case. This case assumes IMPA sets a corporate goal of emitting zero CO2 from owned resources by 2040. In a departure from prior years' IRPs, this is not modeled as a tax, but merely an emission constraint for the IMPA portfolio.

13.2 CARBON POLICY

As noted above, the only "policy" reflected in this case is an IMPA set target of zero emissions by 2040. For the model to optimize the portfolio expansion, this was set up as a phased in constraint to the portfolio starting at 4,500,000 tons per year, gradually dropping to roughly a 50% reduction by 2029, before declining to zero tons by 2040. Figure 45 illustrates the annual portfolio limit.

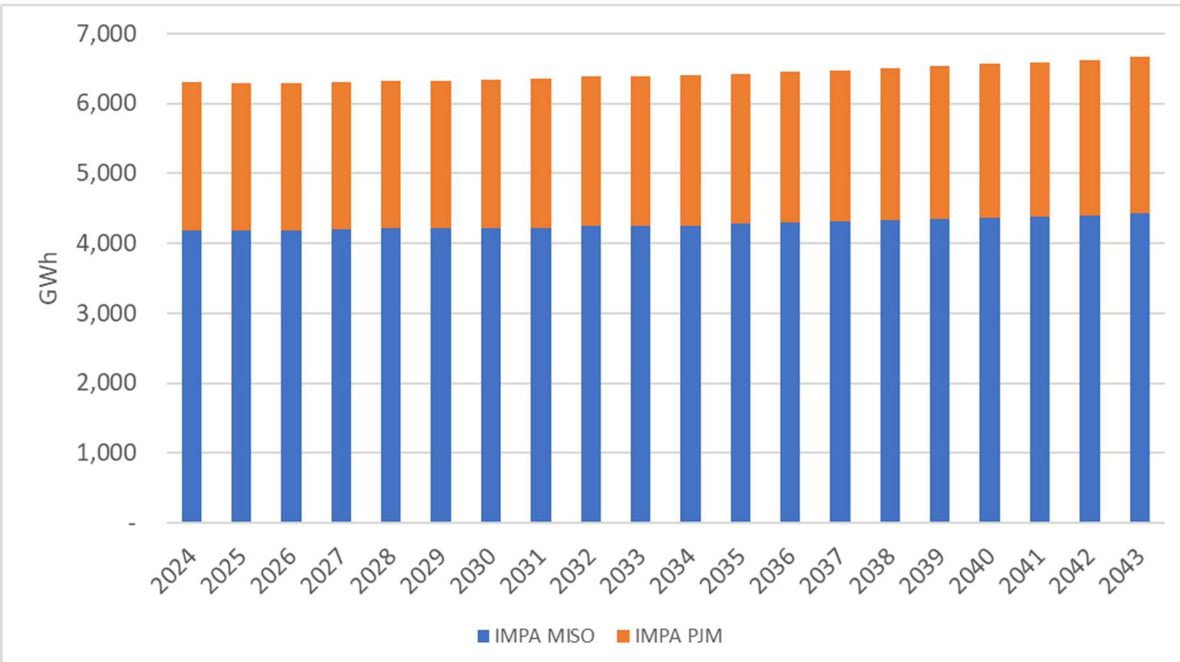
Figure 45 IMPA Portfolio Constraint by Year



13.3 Load Forecasts – IMPA

Under the IMPA Voluntary Net Zero Case, IMPA assumes that their self-directed push towards no CO2 emissions by 2040 is done in conjunction with a broader market push towards shrinking emissions profiles in both the utility sector and transportation sector.

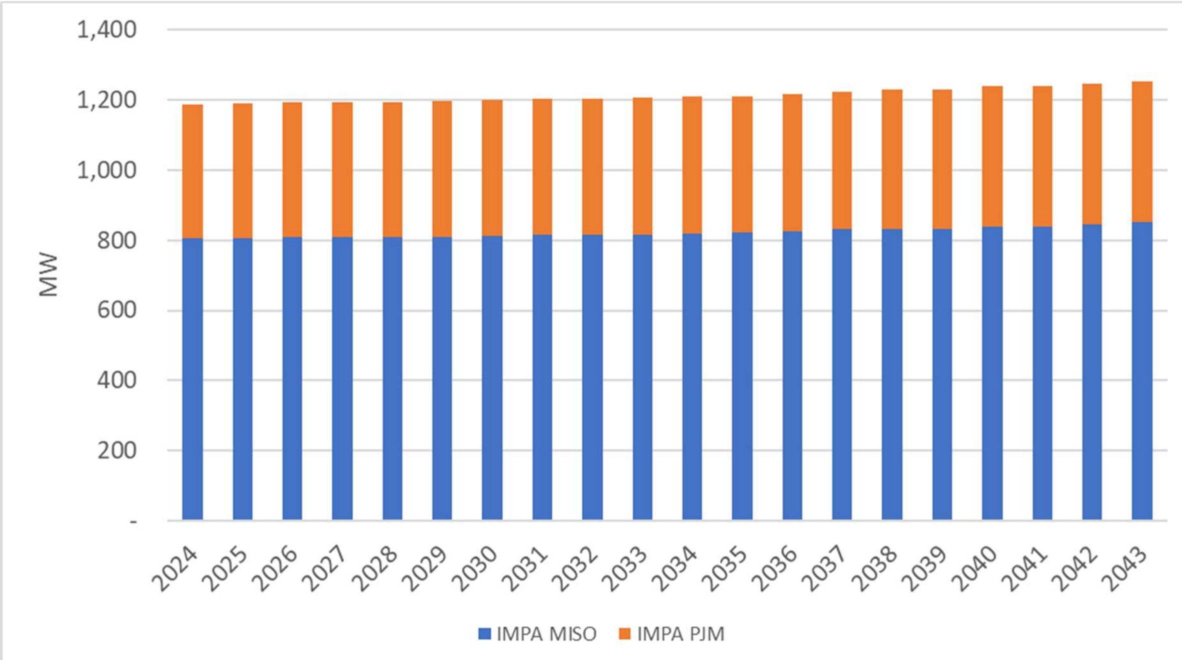
Figure 46 Voluntary Net Zero - IMPA Energy Forecast



Much of the expected difference in the Voluntary Net Zero is driven by higher than base case rates of EV penetration.

The CAGR of the Voluntary Net Zero Case energy forecast is .28% vs. .21% under the base case assumptions.

Figure 47 Voluntary Net Zero - IMPA Demand Forecast



Demand impacts are similar to energy impacts with demand growing at .30% CAGR vs. .20% in the base case. EV penetration in all cases is assumed to fit existing consumption patterns on an hourly basis due to the relatively small amount of incremental load. Underpinning the assumption of high EV penetration in this forecast is a 25% higher than base case growth rate for EV sales. Given that IMPA member communities have a relatively small share of the overall US population, this leads to a relatively small passthrough in terms of EVs on the road in IMPA member service territories. For reference, EPRI recently published a map of near-term electrification needs stemming from EV penetration. An inspection of Indiana, particularly outlying areas typical of IMPA member service territories, shows relatively low expected levels of demand stemming from electrification. [24]

[24] https://eroadmap.epri.com/

13.4 Generation and Technology Costs

The underlying assumption for IMPA's Voluntary Net Zero Case is that IMPA, along with countless others in the electric utility industry, declares a voluntary emissions reduction goal by some set date in the future. To set the bar appreciably high, this date was chosen to be 2040. The current backdrop for renewables is exceedingly negative, however, despite utilities' best efforts to decarbonize. A combination of supply chain disruptions, higher interest rates, and increasingly onerous transmission upgrade costs have driven PPA prices for renewable projects to almost double their pre-pandemic levels. [25]

Figure 48 LevelTen Energy North American PPA Prices

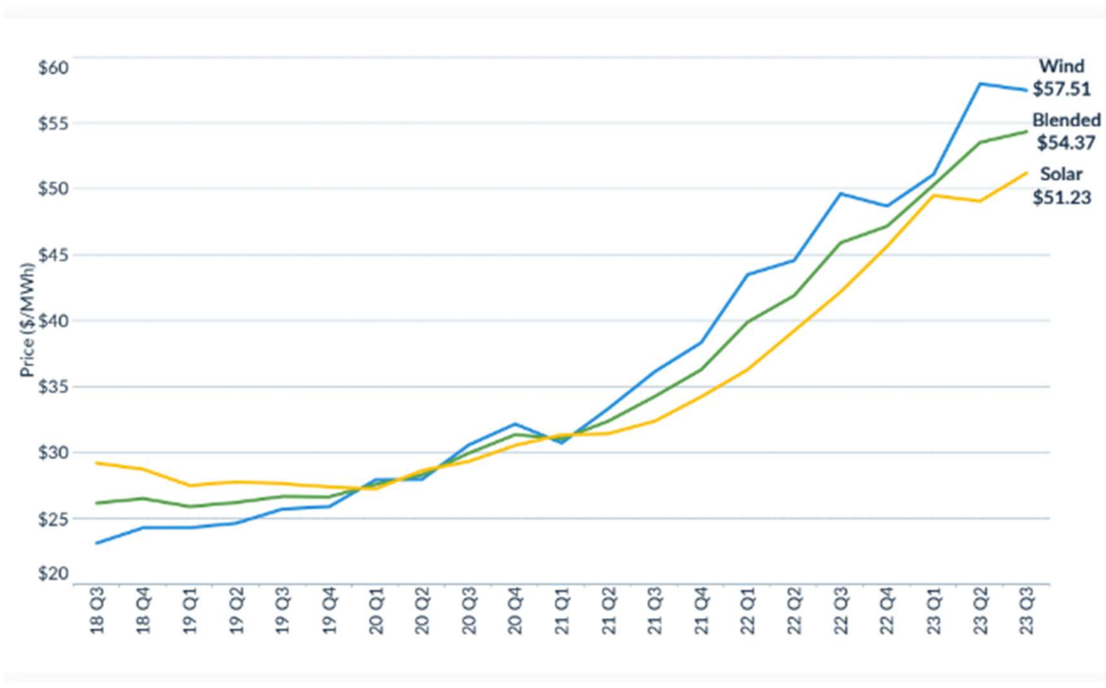


Image: LevelTen Energy

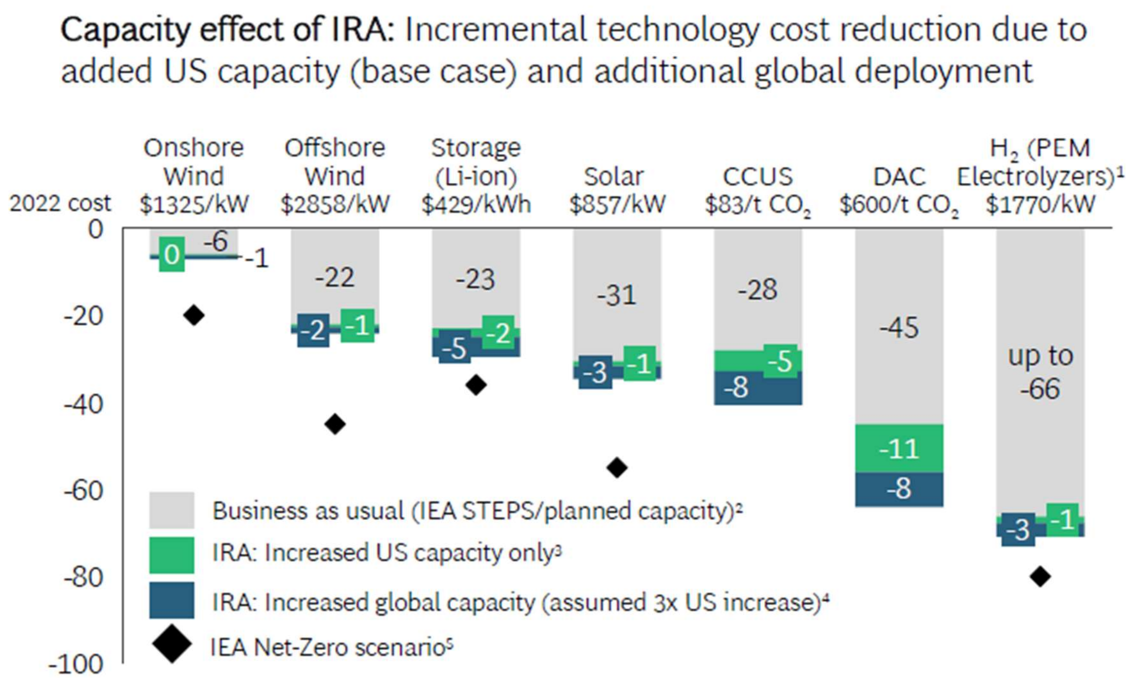
IMPA's experience has been no different with its own renewable PPAs. Pre-pandemic wind and solar projects were relatively inexpensive and IMPA initiated PPA negotiations with one wind and two solar projects. PPAs for the wind and first solar project were successfully negotiated but the rapidly changing economics of PV solar post pandemic led to the first solar project to be amended and restated three times. Negotiations for the second solar PPA have been suspended due to exorbitantly high transmission upgrade costs being assigned to that project.

[25] https://www.pv-magazine.com/2023/10/18/levelten-energy-records-4-increase-in-north-american-ppa-prices-in-q3/

Current interconnection queues, absent pending/proposed reform measures, are experiencing lead times of up to four years in MISO[26] while PJM's queue is currently suspended. While projects are held up in the study process, they face increased cost uncertainty due to Engineering, Procurement, and Construction (EPC) contract timing. A vast push across the industry to electrify will likely only serve to increase cost pressures.

However, according to a Boston Consulting Group (BCG) report on the impacts of the Inflation Reduction Act, there is potential for costs for renewable projects to fall over time due to increased investment and improved learning rates. [27]

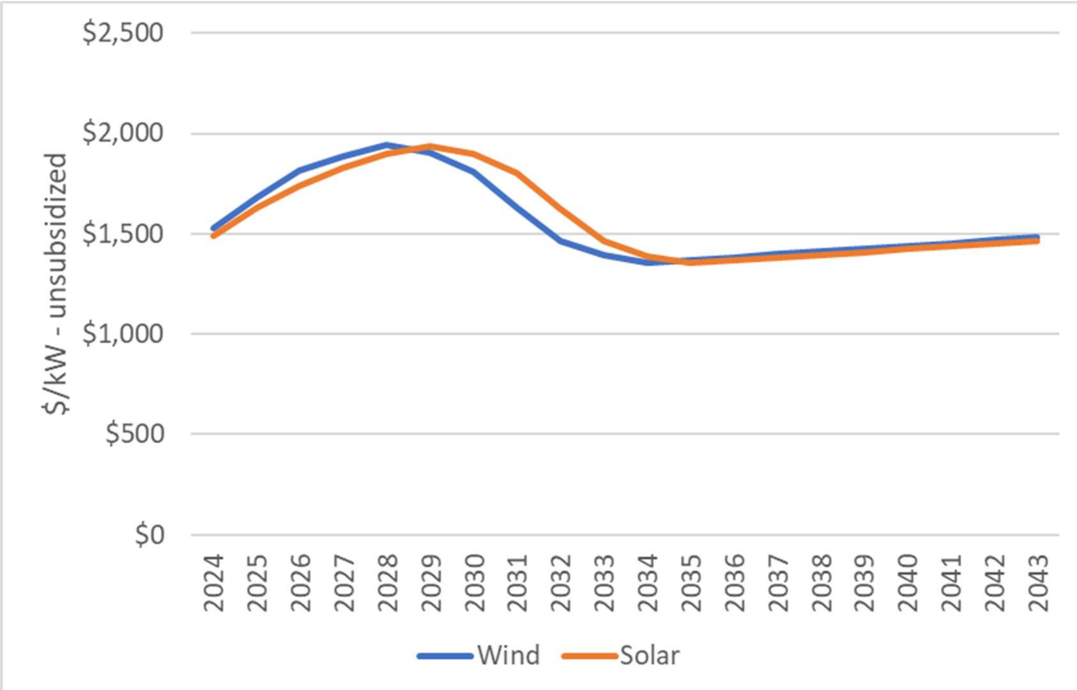
Figure 49 BCG Incremental Cost Reductions – Capacity Effect



These figures reflect BCG's estimates for cost declines in 2030 resource costs from 2022 levels. IMPA's approach, however, was to assume, for wind and solar, that short run CAPEX for wind and solar continues to trend higher before the BCG cost reductions come into play. Figure 50 illustrates IMPA's mapping of these impacts on installed costs per kW.

[26] https://cdn.misoenergy.org/Definitive%20Planning%20Phase%20Schedule629192.pdf
[27] BCG Executive Perspectives, "US Inflation Reduction Act: Global Implications" December 2022

Figure 50 - IMPA Blended Wind & Solar CAPEX



For large renewable projects, IMPA converts assumed CAPEX into an equivalent PPA price based on cash flows and target return requirements to both tax equity and sponsor equity. For the No CO2 case, IMPA further assumes that project developers in a crowded marketplace will be forced to compete for the full suite of ITC/PTC bonuses to be competitive. Consequently, IMPA assumes a 50% ITC for Solar and $33/MWh PTC for wind.

However, in spite of these full tax credits, IMPA assumes that interconnection queues remain backlogged and interconnection costs remain high, effectively negating much of the increased benefit.

Consequently, PPA equivalent prices under the No CO2 case are the same as the base case, with solar being priced at $77/MWh for the duration of the study and wind being priced at $55/MWh.

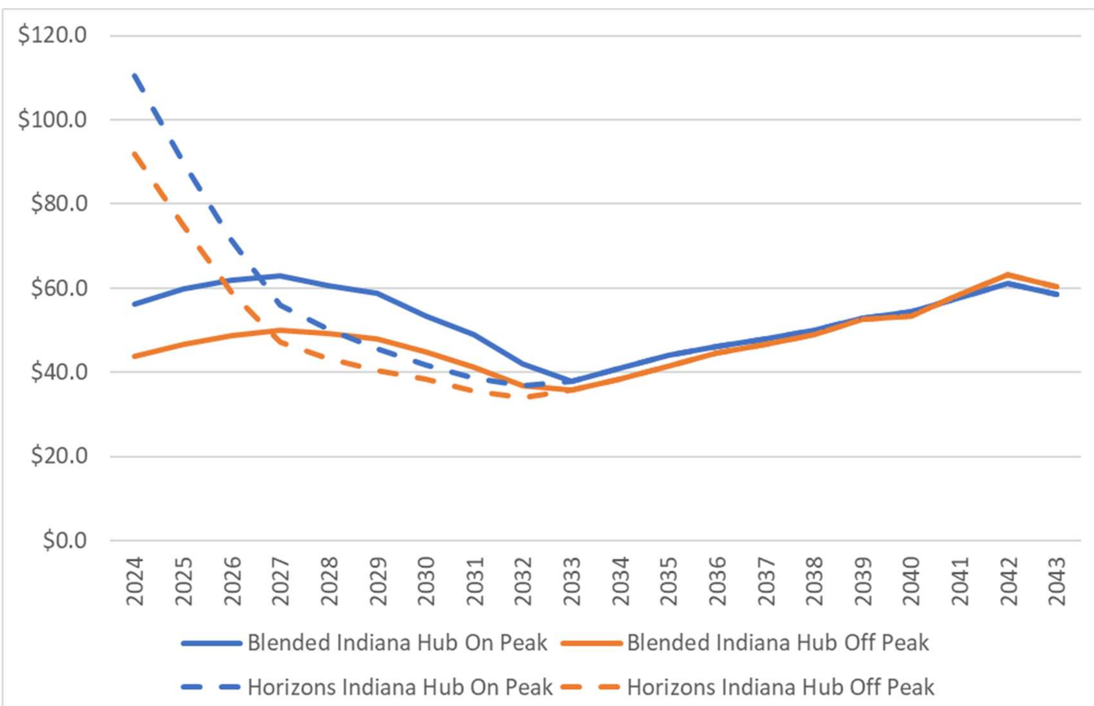
Finally, small modular reactors were assumed to keep their base case CAPEX but with a 50% PTC.

13.5 FORWARD PRICES

Forward price formulation for the Voluntary Net Zero Case was done in the same general way as was handled for the base case. However, rather than using three different sources, IMPA utilized forward prices from Nodal Exchange and forward prices forecasts from Horizons, with a gradual blending of curves beginning in 2028. The blended prices gradually phase in forecast power prices for Indiana Hub and AEP Dayton Hub using Horizons scenario pricing from their High Natural Gas/CO2 limited world.

Blending prices with the known and executable market prices seen on Nodal Exchange results in near term pricing that is very similar to the base case pricing until blending in of the Horizons prices in 2028. Overall, Horizon's High Natural Gas/CO2 limited world yields higher long-term prices than the IMPA Base Case prices. This is driven by uncertainty around long term natural gas production. In their analysis, higher feed stock prices for gas fired units lead to increased margins for wind and solar, lowering the penetration of natural gas builds. [28] However, as an extension of this, it would lead to gas being on the margin more often and at a higher price due to the higher marginal cost overall.

Figure 51 Voluntary Net Zero Price Forecast Comparison



Source: Horizons Energy Fall 2022 Advisory

[28] Horizons Energy Advisory Fall 2022

Under the Voluntary Net Zero Case, market implied heat rates are generally higher than in the Base Case due to the underlying assumption of higher overall demand for electricity. However, from an IMPA portfolio perspective this becomes moot as the portfolio is constrained to achieve zero carbon emissions from owned resources by 2040.

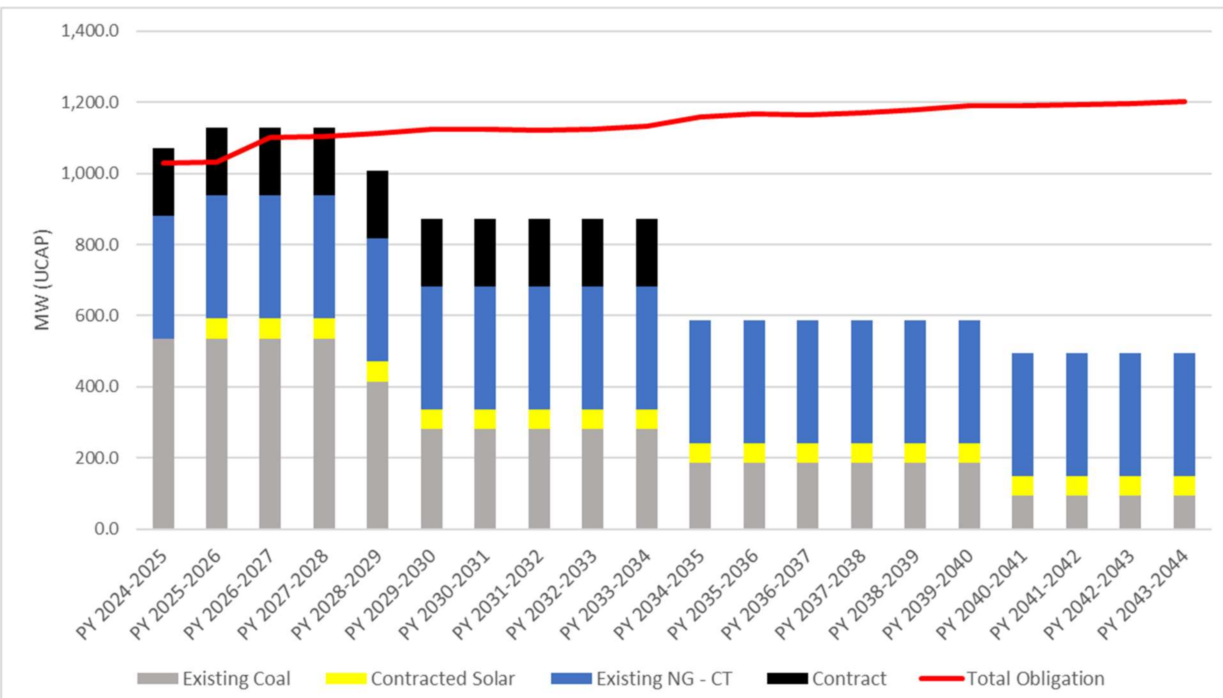
13.6 ALL SOURCE RFP

Resources from the All-Source RFP were added to the Voluntary Net Zero Case as selectable resources.

13.7 PORTFOLIO SELECTION

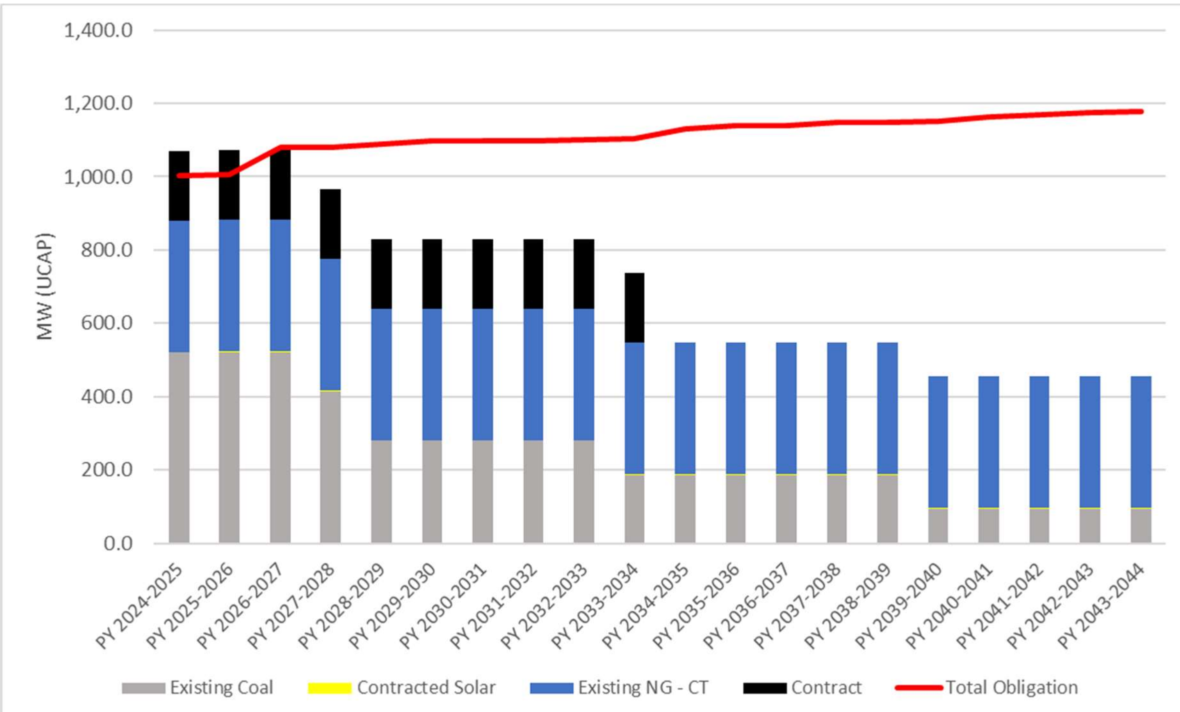
With an aggressive CO2 emissions reduction target, the portfolio mid optimization position is a bit more severe in terms of replacement capacity and energy requirements due to the optimized retirements required to get the portfolio to net zero.

Figure 52 Voluntary Net Zero Mid Optimization Capacity Position – Summer



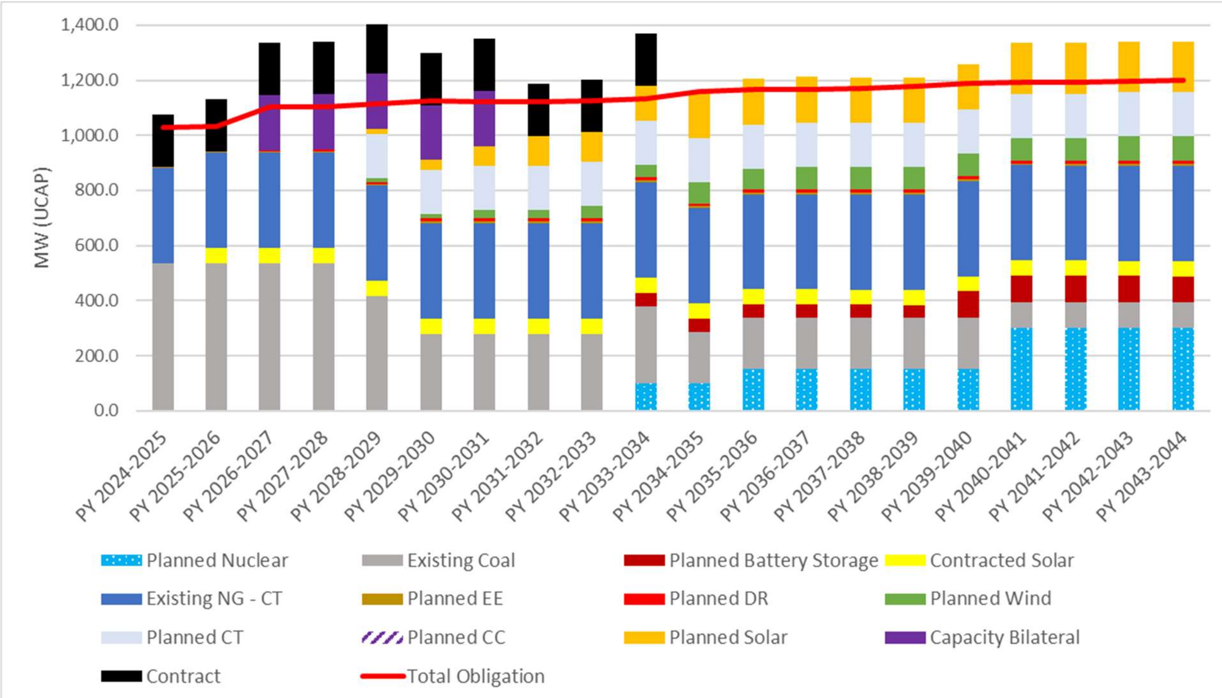
Combined with the AEP Full Requirements contract expiration, the Voluntary Net Zero Case sees a swath of coal retirements by Planning Year 34-35, leading to a nearly 600MW shortfall relative to expected load obligations.

Figure 53 Voluntary Net Zero Mid Optimization Capacity Position – Winter



Despite the voluntary requirement for zero carbon emissions by 2040 in this case, it is important to note that some existing coal and natural gas resources are retained to meet capacity obligations despite not being utilized for energy. This is due to their ongoing fixed cost being less than the cost of new entry. Figure 54 illustrates the capacity expansion for the Voluntary Net Zero Case for the summer.

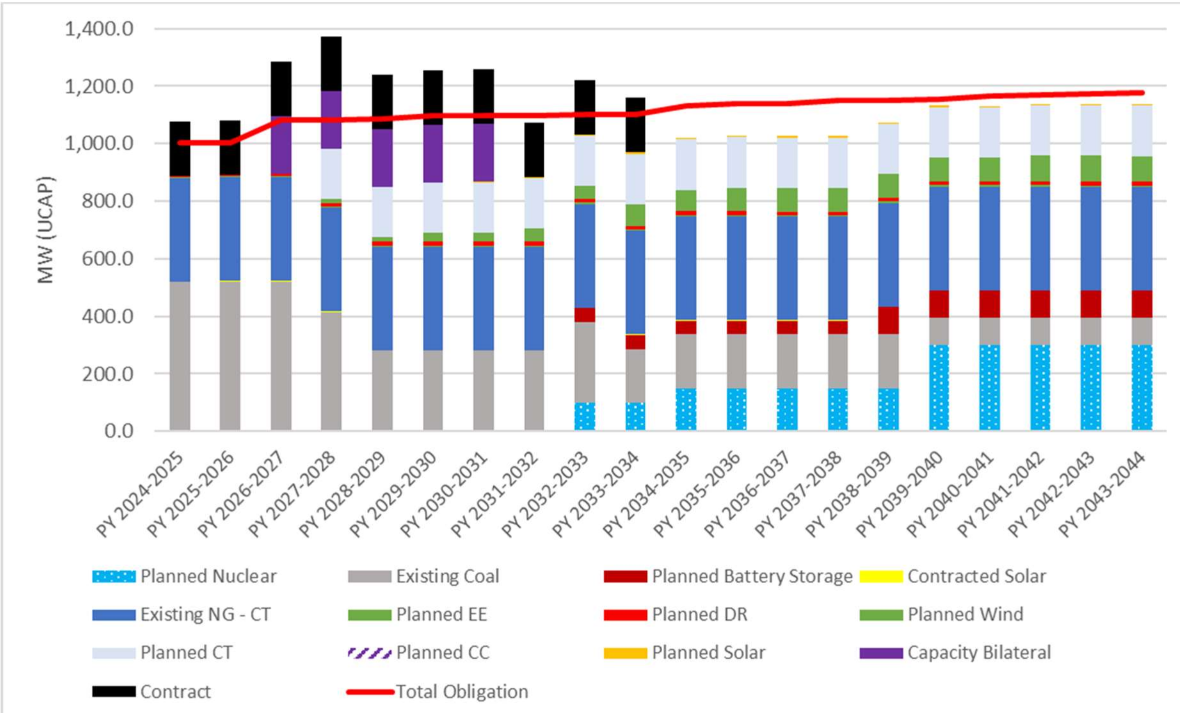
Figure 54 Voluntary Net Zero Expansion – Summer



As the portfolio transitions to net zero, more immediate needs are filled with a combination of a natural gas combustion turbine, solar, wind, energy efficiency/demand response, and battery storage. As baseload coal retirements accelerate, however, the portfolio requires replacement firm energy and capacity that is carbon free. The most suitable replacement comes in the form of Small Modular Reactors ("Planned Nuclear").

Figure 55, on the following page, illustrates the winter capacity position.

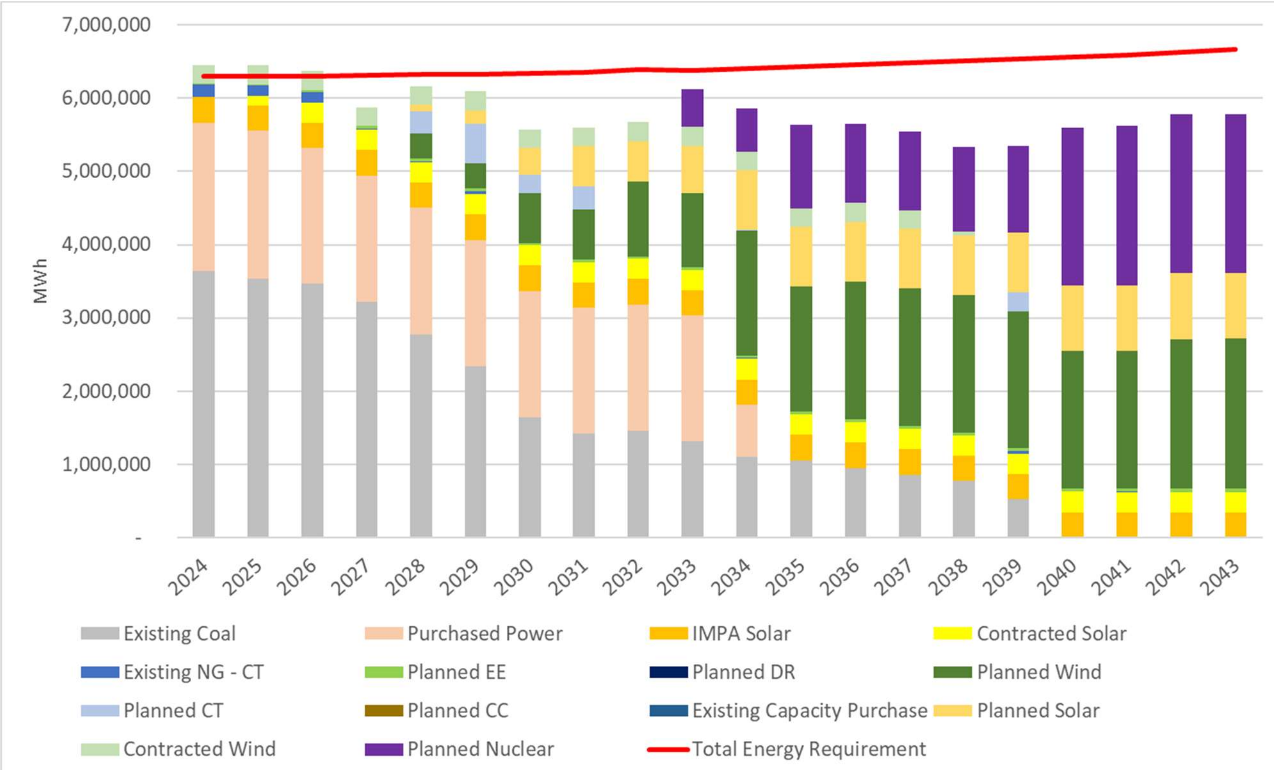
Figure 55 Voluntary Net Zero Expansion – Winter



The winter optimization builds just short of the requirement for a handful of years as it is cheaper to leave that position to market versus the cost of the next incremental build, which is an SMR. The addition of incremental SMR capacity also coincides with the target date to achieve net zero CO2 emissions, as well as a general upward trend in forecasted power prices.

Figure 56, on the following page, illustrates the annual energy position.

Figure 56 Voluntary Net Zero Annual Energy Position



As was the case with the Base Case energy position, there is a small portion of energy being served by spot market purchases in the out years of the study.

13.7.1 MISO Portfolio Discussion

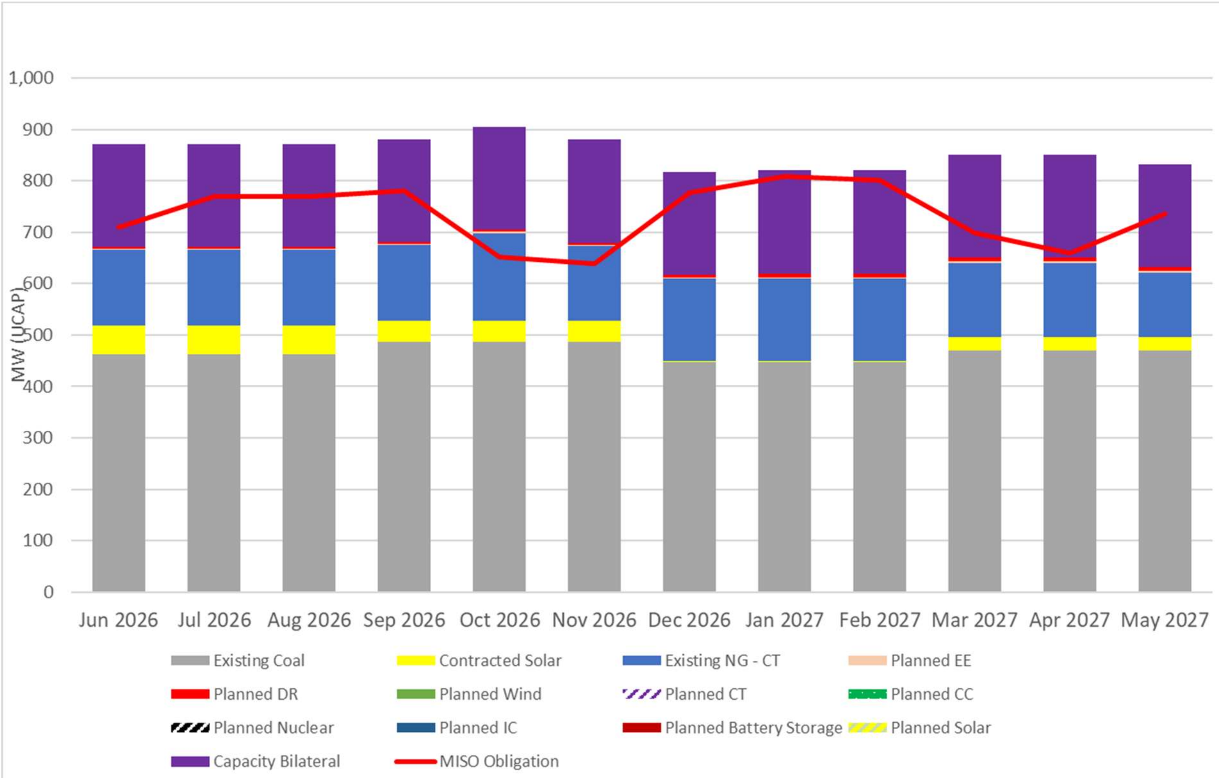
The Voluntary Net Zero case follows a very similar build plan in the short to intermediate term as the base case with the exception of an early, smaller CT build and the incremental addition of solar and wind PPAs to the MISO portfolio mix. The new CT is built earlier than in the base case due to balancing new resource additions versus retirements needed to meet the CO2 reduction requirement. The net position is merely a reflection of the capacity additions/retirements shown in the table and not a full accounting of the MISO capacity position.

Table 23 Near to Intermediate MISO Portfolio Milestones – Voluntary Net Zero

Near to Intermediate Term Milestones - IMPA MISO Portfolio - Voluntary Net Zero						
Date	**Resource**	**+/- MW (ICAP)**	**+/- MW (Summer UCAP)**	**+/- MW (Winter UCAP)**	**Summer Position Long/(Short)**	**Winter Position Long/(Short)**
PY 24/25					(88)	(118)
Jul 2025	Ratts Solar	150	55	2	(33)	(117)
May 2026	Existing Bilateral Capacity	(75)	(75)	(75)	(108)	(192)
Jun 2026	New Bilateral Capacity	200	200	200	93	9
Jan 2028	Gibson 5 Retirement	(156)	(121)	(106)	(29)	(97)
Jan 2028	IMPA Self Build CT COD	200	160	175	131	78
Jan 2028	Solar PPA	50	19	1	150	78
Jan 2028	Wind PPA	100	15	15	165	93
Jan 2029	Solar PPA	50	19	1	183	94
Jan 2029	Trimble County 1 retirement	(64)	(62)	(62)	121	31
Jan 2030	Solar PPA	50	19	1	140	32
Jan 2030	Wind PPA	50	15	15	155	47
May 2031	New Bilateral Capacity	(200)	(200)	(200)	(45)	(153)

The first key milestone year is Planning Year 26-27, where a 200 MW bilateral capacity contract is added. This flattens the portfolio's position relative to the winter obligation, which is driven by a combination of high reserve margin requirements and low solar accreditation. Figure 57 illustrates the capacity position for this initial milestone year.

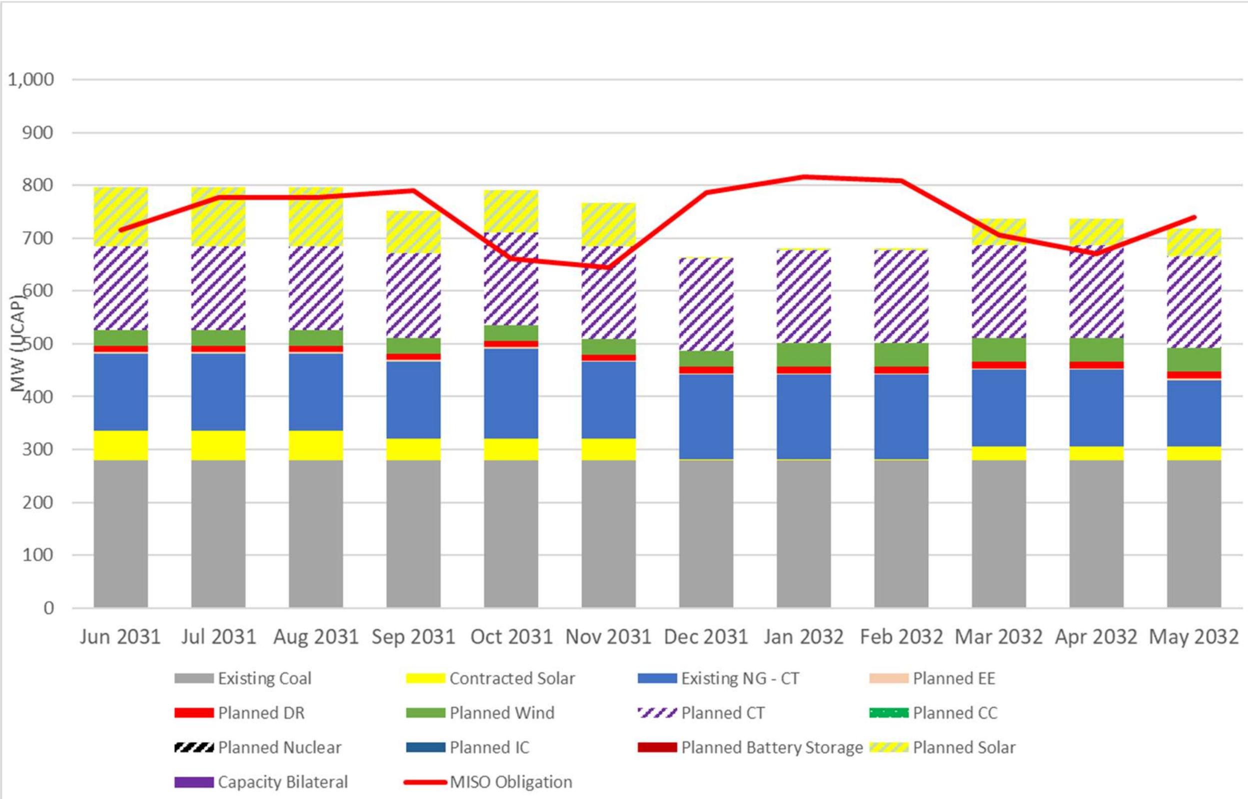
Figure 57 MISO Market Capacity Position Planning Year 26-27 – Voluntary Net Zero



While the bilateral contract does create some length in certain seasons it does hedge IMPA from further increases in planning reserve margins and potential risk to resource accreditation.

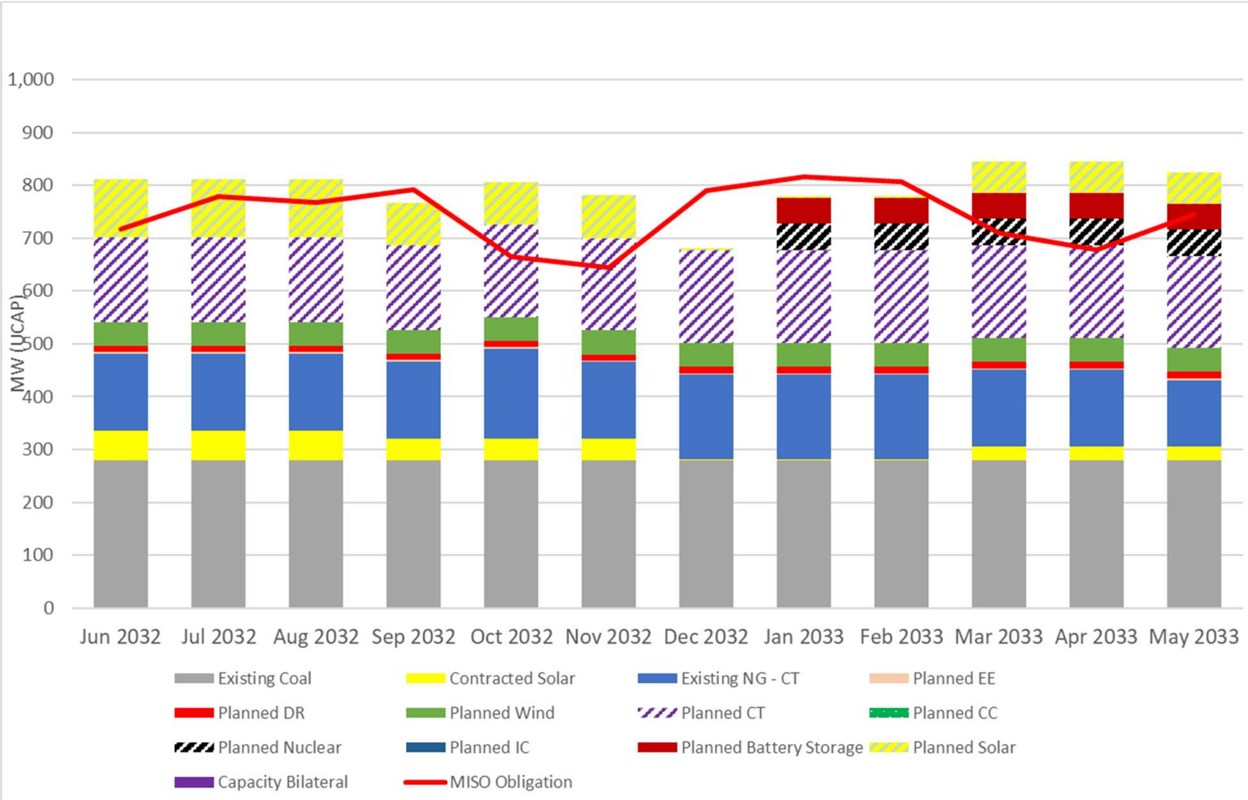
The next milestone year is the commissioning of a smaller natural gas CT in early 2028. Combined with the capacity bilateral, this makes IMPA's MISO portfolio long relative to requirements. However, with the expiration of the capacity bilateral in Planning Year 30-31, the portfolio becomes slightly short again in the Winter season of Planning Year 31-32. Figure 58 illustrates the Planning Year 31-32 MISO capacity position after the expiration of the bilateral and also illustrates the renewable capacity additions.

Figure 58 MISO Market Capacity Position Planning Year 31-32 – Voluntary Net Zero



This short position is short lived however, as Planning Year 32-33 sees the addition of blocks of battery storage and nuclear (SMR) capacity. Figure 59 on the following page illustrates the initial addition of both the battery storage and SMR capacity. With SMRs encountering development challenges recently, this portfolio positioning would be extremely aspirational assuming a 10-year development timeline for nuclear technologies.

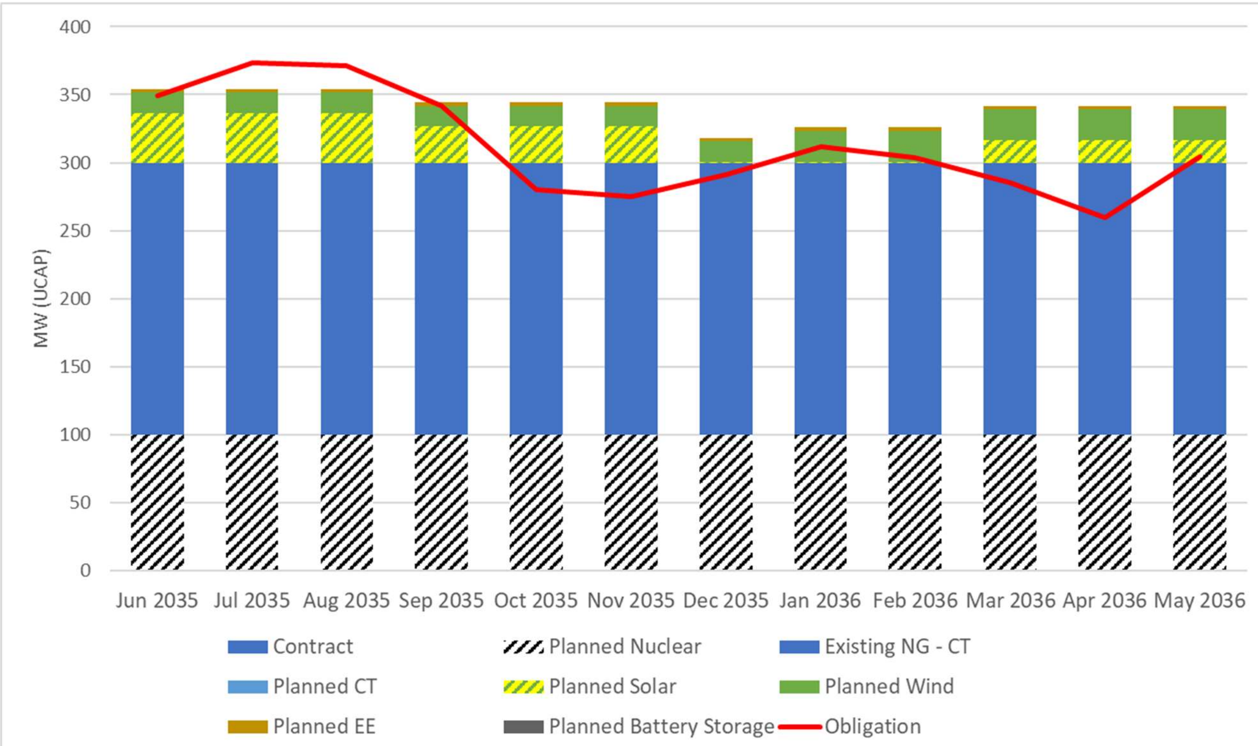
Figure 59 MISO Market Capacity Position Planning Year 32-33 - Voluntary Net Zero



13.7.2 PJM Portfolio Discussion

IMPA's known portfolio needs in the Voluntary Net Zero Case are due to the expiration of the AEP Full Requirements contract in Planning Year 34-35. From a UCAP basis, the largest additions are nuclear (SMR) in addition to solar, wind, and EE.

Figure 60 PJM Market Capacity Position Planning Year 35-36 – Voluntary Net Zero



As the chart above is in UCAP terms, it is notable that CTs backstop the emission free additions and that roughly 150 MW of ICAP wind and solar are added, largely to meet the energy requirements of the portfolio.

13.8 RISK ASSESSMENT

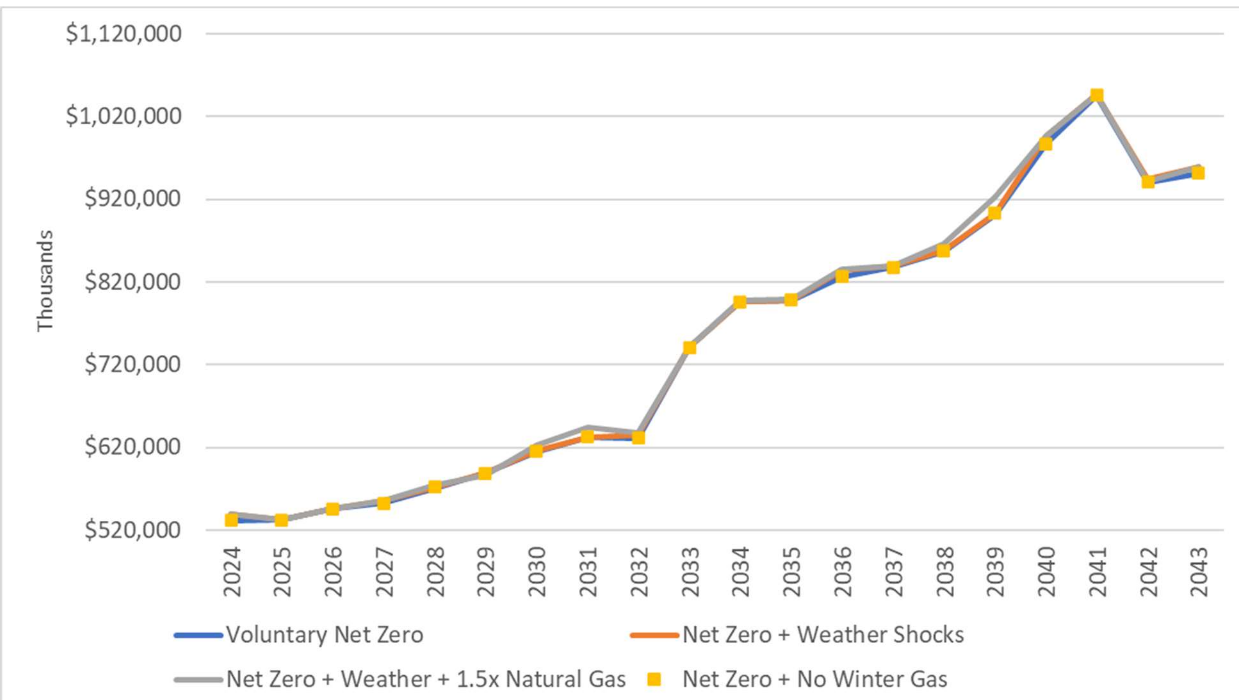
Process

The risk assessment process for the Voluntary Net Zero case was the same as the Base case with the selection of winter storm events and recent summer max gen events modeled against the portfolios.

Results

What stands out in the Voluntary Net Zero Case is the relatively tight distribution of NPVRRs over the 20-year study horizon. While the NPVRRs are much higher than the base case, the Net Zero portfolio is only moderately impacted by disruptions in weather or fuel prices. Fuel prices make sense since the portfolio is entirely carbon free by 2040, however, the addition of nuclear power to the portfolio makes for an additional layer of resilience.

Figure 61 Annual NPVRR Between Cases – Voluntary Net Zero



The large jump up in the 2033 revenue requirements is due to additions of nuclear capacity in the portfolio. Nuclear is continuously layered in the portfolio over the study horizon which complements the renewable energy additions. The minor increase in the high natural gas case in 2038 and 2039 stems from higher natural gas generation utilization before converging to the other cases in 2040 and beyond.

Table 24 illustrates the NPVRR and rate impacts across the cases and various sensitivities.

Table 24 NPVRR and Rate Impact Comparisons

Case/Sensitivity	20 Year NPVRR	20 Year Levelized Rate	10 Year NPVRR	10 Year Levelized Rate
Voluntary Net Zero	$7,932	$109.34	$4,304	$93.44
Net Zero w No Winter Gas	$7,937	$109.41	$4,308	$93.53
Weather Shock	$7,959	$109.71	$4,319	$93.77
Weather Shock + 1.5X Gas	$7,983	$110.05	$4,332	$94.05

No winter gas does not impact the portfolio much as it is effectively free of fuel exposure by 2040. Weather impacts have a more notable effect over the Voluntary Net Zero Case but summer RA hours are somewhat insulated by the portfolio's addition of solar resources while nuclear helps insulate the portfolio during winter storms that typically disrupt natural gas supplies. In fact, where the Base Case saw a 2% jump in the 20 year levelized rate from baseline to Weather + 1.5X Natural Gas, the Voluntary Net Zero Case only rose a little over .5%.

This comes at a cost however, with 20 year levelized rates being 19% higher than the Base Case ($109.34 vs. $91.53). Because IMPA assumed the maximum allowable ITC for renewables and nuclear, these rates are likely very optimistic versus a real-world implementation of such a plan.

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14 AUSTERITY CASE

14.1 IRP Scenario Development

Under the Austerity Case, IMPA assumes that provisions of the Inflation Reduction Act of 2022 fall victim to Congressional budget cuts. Under this assumption all generation is built at pre-subsidized cost under the Base Case CAPEX assumptions. The most dramatic impact is the loss of the 35% ITC or $27.50/MWh PTC.

Further, IMPA assumes the Austerity Case represents an economic backdrop that requires a broader level of economic retrenchment than just repealing tax benefits for carbon neutral technologies and that consumers will also cut back on overall consumption, including electricity.

14.2 Carbon Policy

The Austerity Case assumes no requirement to reduce or curtail carbon emissions.

14.3 Load Forecasts - IMPA

The Austerity Case sees overall lower loads and lower overall rates of EV penetration than either the Base Case or the Voluntary Net Zero Case. Under this case, loads grow a very modest .14% while demand is expected to stay flat.

Figure 62 Austerity Case – IMPA Energy Forecast

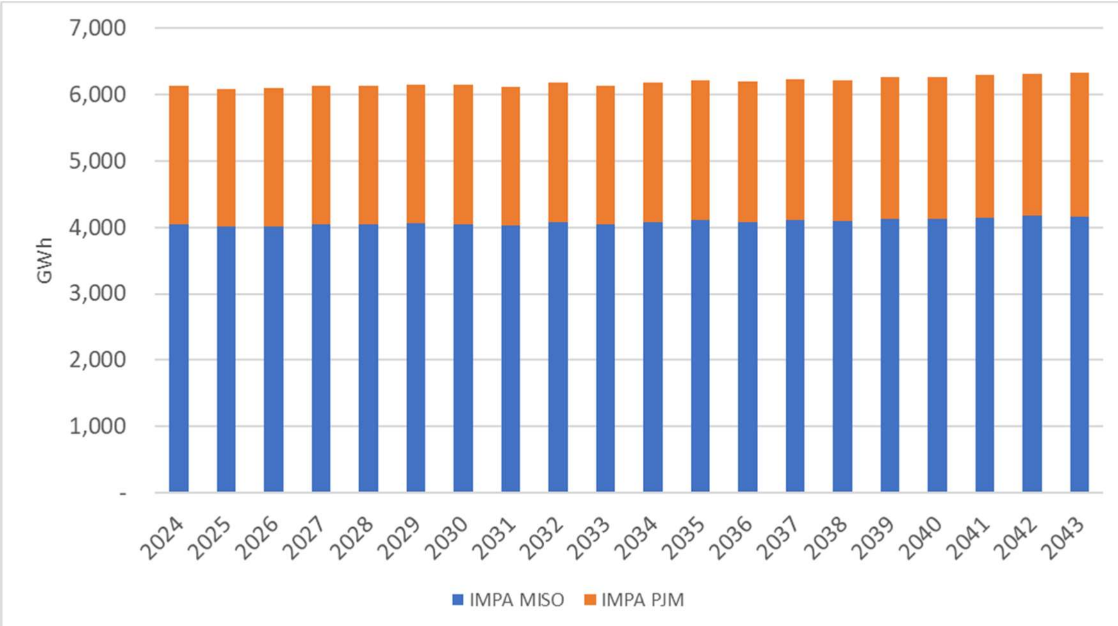
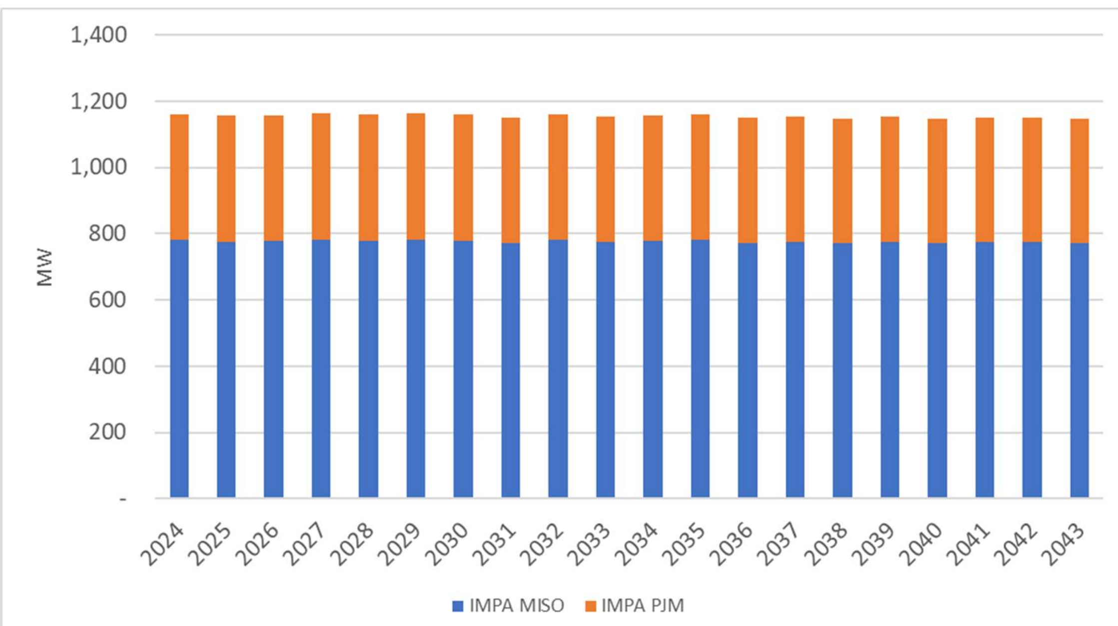


Figure 63 Austerity Case - IMPA Demand Forecast



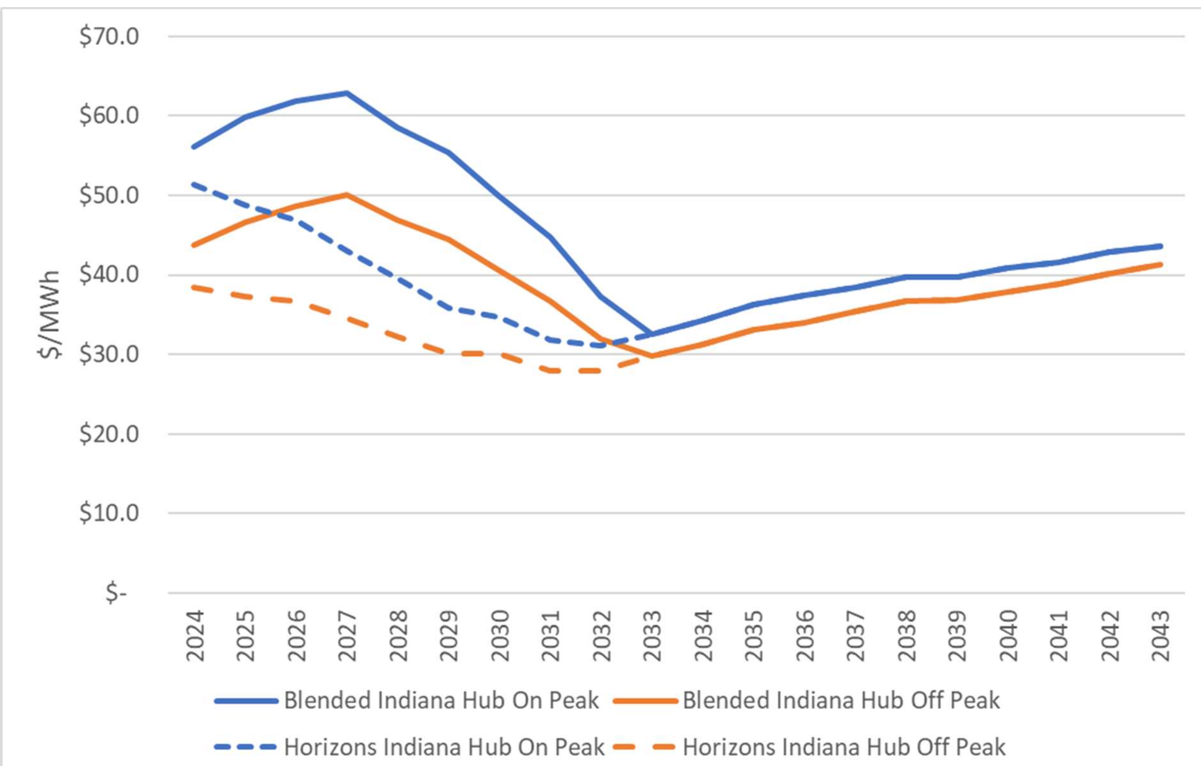
14.4 Generation and Technology Costs

Apart from a loss of tax credits, generation and technology costs remain the same for the Austerity Case as the Base Case. Notably, when solar and wind projects are converted into PPAs via IMPA's internal project finance model, the loss of the tax benefits moves solar PPAs from $77/MWh to $144/MWh and wind goes from $55/MWh to $78/MWh. Solar suffers from relatively low capacity factors without the tax benefits and requires a much higher PPA price than wind to make up for the loss of the ITC.

14.5 Forward Prices

Forward price formulation for the Austerity Case was done in a similar manner to the Voluntary Net Zero Case. The blended prices gradually phase in forecast power prices for Indiana Hub and AEP Dayton Hub using Horizons scenario pricing from their Low Natural Gas/Low Demand case. The combination of stagnant power prices with sustained, low natural gas prices in this case lead to persistently high market implied heat rates.

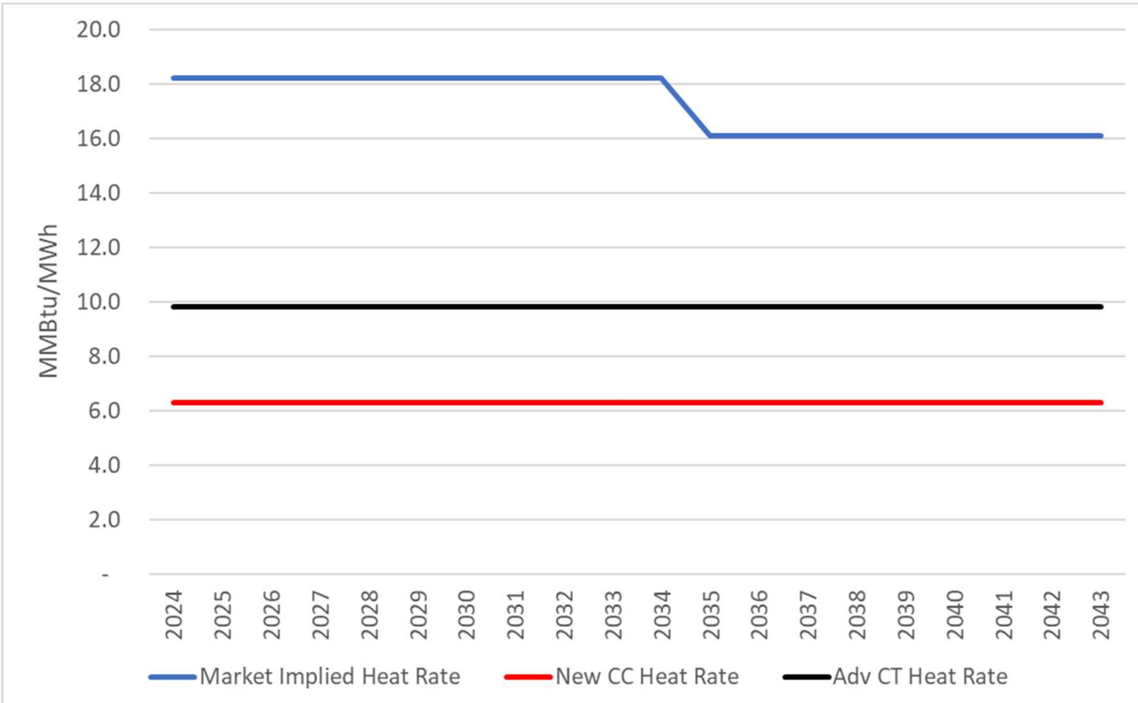
Figure 64 Austerity Case Price Forecast Comparison



Source: Horizons Energy Fall 2022 Advisory

Prices under the Austerity Case are actually somewhat higher than the base case. This is due to an assumed loss of federal tax incentives which in turn drives lower levels of renewable penetration. Due to lower natural gas prices also assumed, market heat rates for all natural gas generation technologies are favorable.

Figure 65 Austerity Case Market Implied Heat Rates



As Figure 65 illustrates, the market price environment for both new combined cycles and combustion turbines is expected to be favorable relative to their expected fuel costs.

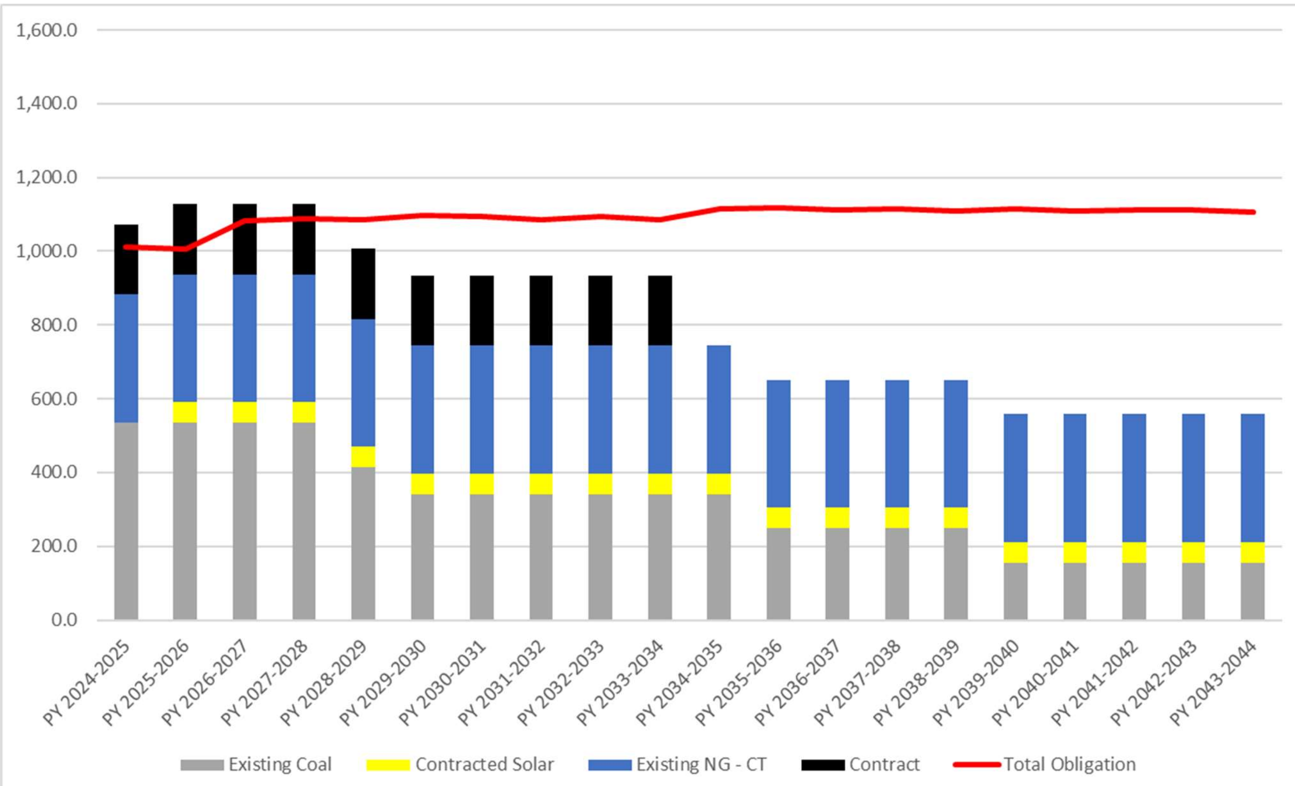
14.6 ALL SOURCE RFP

As was the case in the Base Case and Voluntary Net Zero cases, economic resources that were deemed to be good candidates for IMPA's portfolio requirements were added as selectable resources.

14.7 Portfolio Selection

As was the case with the Base and Voluntary Net Zero cases, Encompass was allowed to optimize the MISO and PJM portfolios under the core assumptions of the Austerity Case. With no CO2 constraints, apart from the CEJA constraint impacting Prairie State, resource retirements impacting the position are largely the same impacting the base case, with slightly variable timing, however.

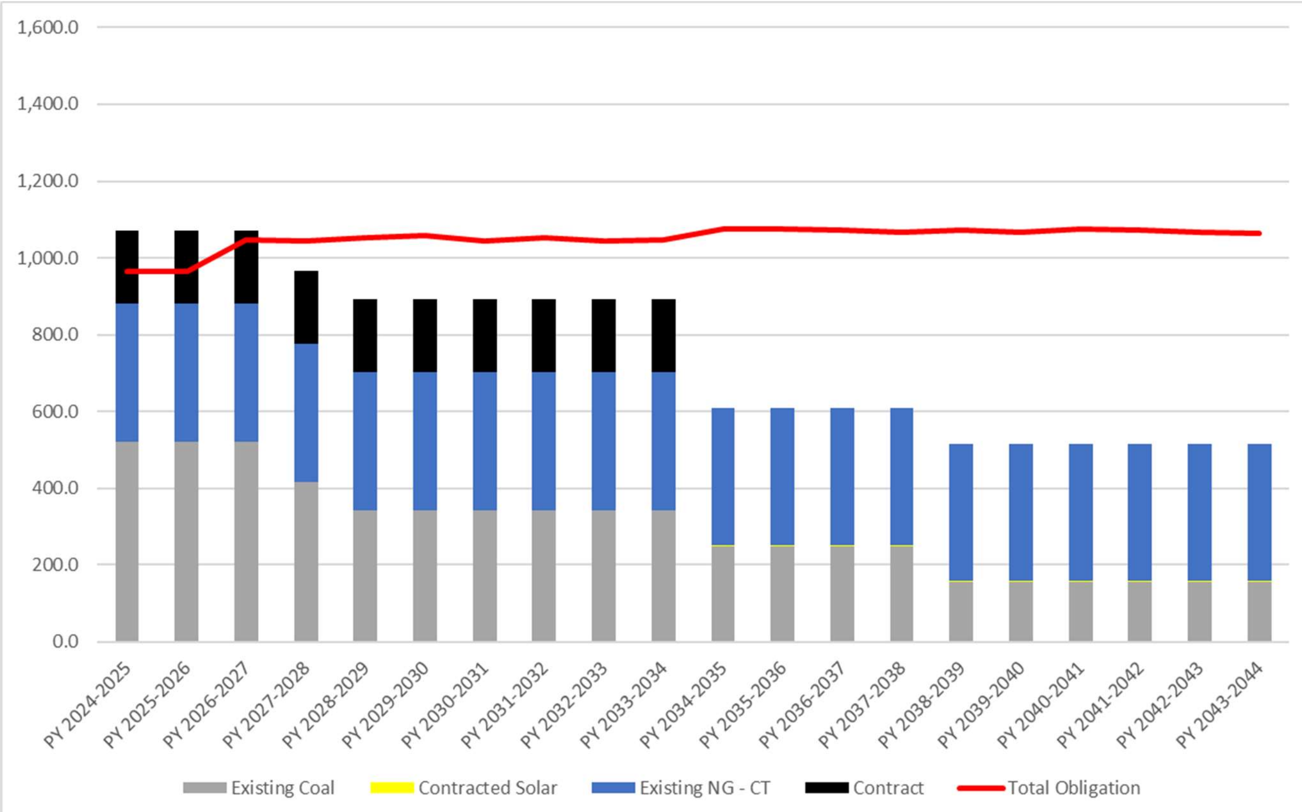
Figure 66 Austerity Case Mid Optimization - Summer



The summer going in position is primarily impacted by Gibson 5 and WWVS retirements in the near term, while PSGC retirements occur in Planning Year 35-36 and Planning Year 39-40. Also, as in previous cases, the Planning Year 34-35 expiration of the AEP baseload contract looms.

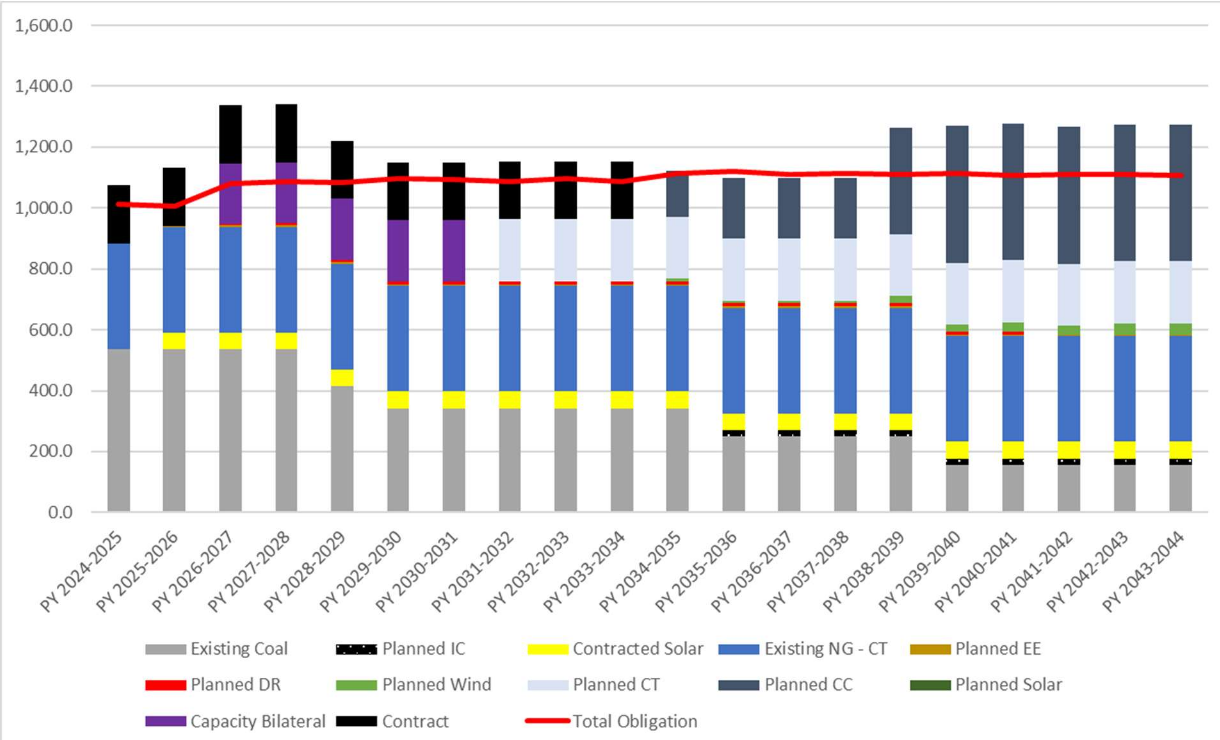
The winter position looks much the same as the summer mid-optimization portfolio. Similar to all previous cases, Ratts Solar is expected to not fulfill much of the winter capacity obligation shown in Figure 67.

Figure 67 Austerity Case Mid Optimization - Winter



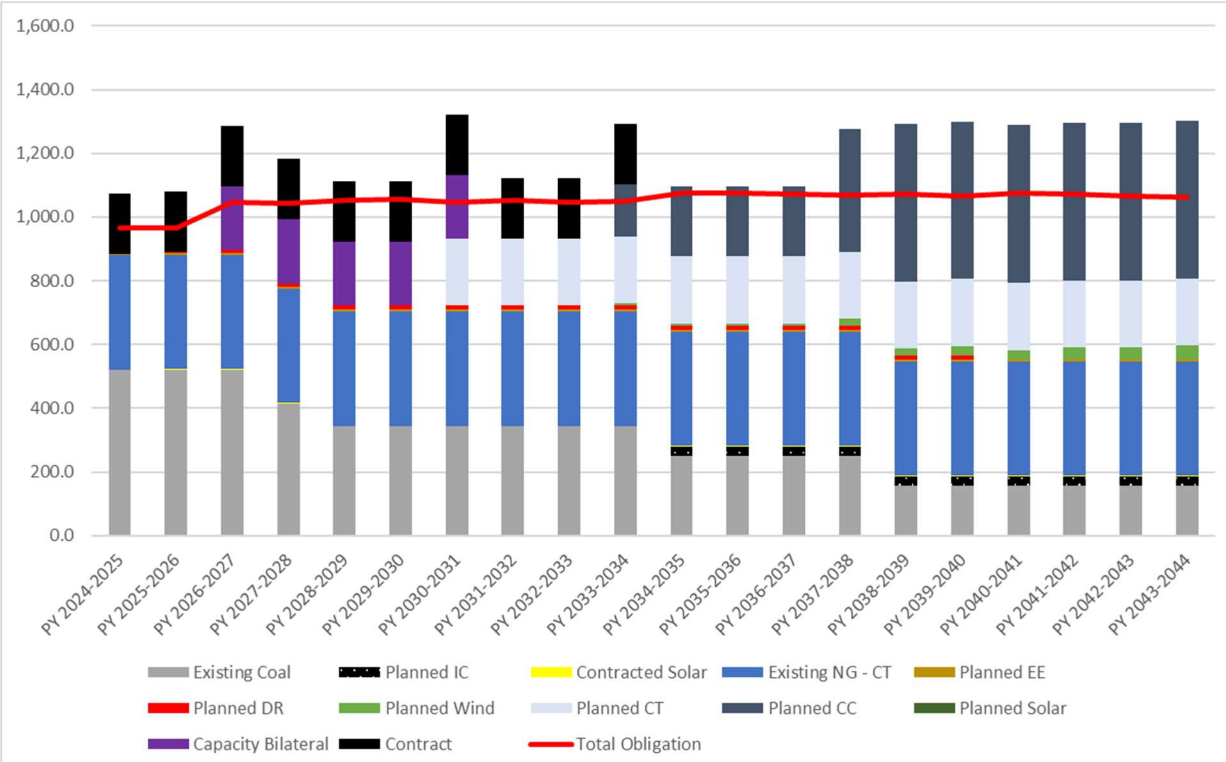
The following figures will highlight the Austerity Case expansion for IMPA for the summer and winter seasons.

Figure 68 Austerity Case Optimization - Summer



As noted in Section 14.5, the forward price environment, relative to natural gas prices, is favorable in this case for natural gas builds. Specifically, simple cycle combustion turbines and combined cycles are the primary sources of new generation, combined with EE and Demand Response. Capacity length in the out years of the optimization is primarily due to energy requirements coupled with the retention of existing CTs. In this case, the only renewable energy that is economically competitive with natural gas is wind. Solar is not viable without the ITC assumed under the Inflation Reduction Act. The winter optimization position, shown in Figure 69, is somewhat longer in the out years on lower load obligations. However, this length, as was the case in summer, was due to energy requirements.

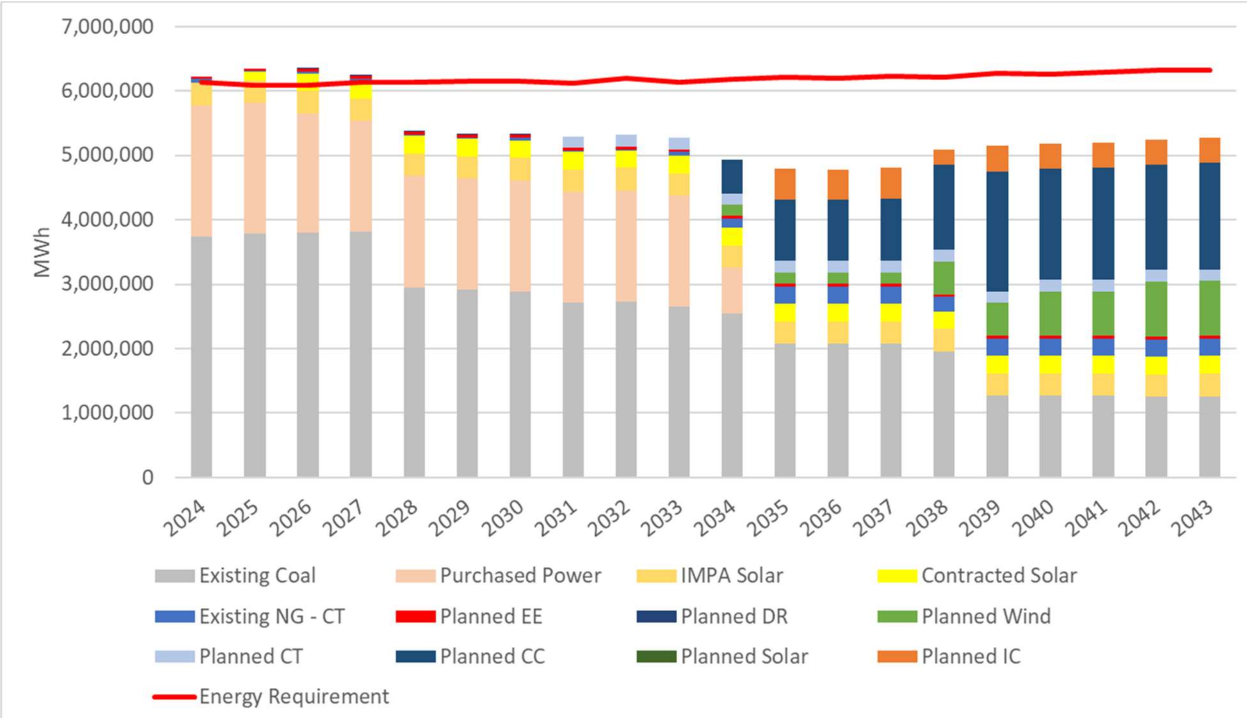
Figure 69 - Austerity Case Optimization – Winter



While all portfolios in all cases have an energy requirement and some degree of limitation on market access, renewable energy resources tend to allow for a greater degree of customization in co-optimizing the energy and capacity positions. Wind, for example, may supply a decent portion of energy over a given year, but only a small portion of the capacity. When paired with solar, which supplies healthy summer capacity, but low annual energy, there is a complementary effect. However, combined cycles as modeled come in fixed blocks. With a lack of economic alternatives, the model must select the most economic resource to meet either some incremental capacity or energy need, and in the austerity case this is the combined cycle block. Some modulation is afforded by the addition of a single Internal Combustion unit.

Figure 70 illustrates the energy position of the Austerity Case. Some portion of the energy position is expected to be served by market or spot purchases.

Figure 70 - Austerity Case Energy Position



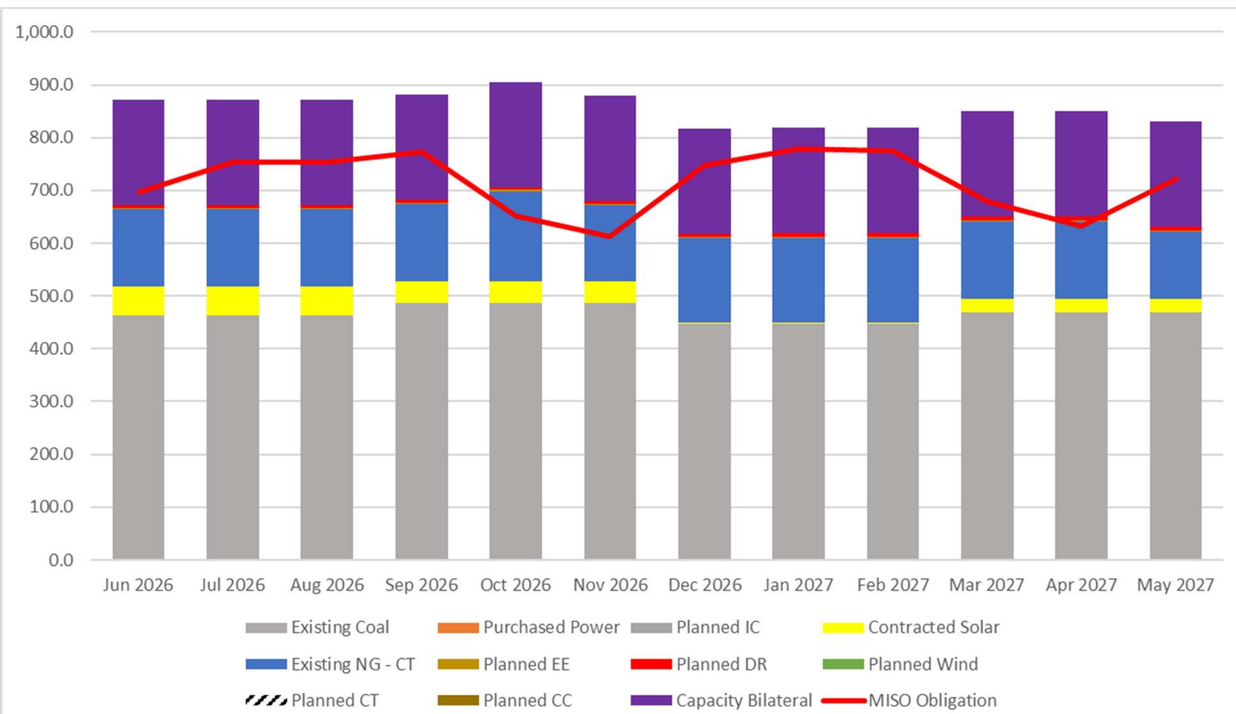
14.7.1 MISO Portfolio Discussion

The MISO portfolio expansion is essentially the same as the Base Case expansion apart from no solar additions to the Austerity Case portfolio. Table 25 on the next page illustrates the milestone capacity additions/retirements and an estimated position after each addition or retirement. It is not a full accounting of the position however.

Table 25 MISO Portfolio Milestones - Austerity Case

Near to Intermediate Term Milestones - IMPA MISO Portfolio Austerity Case						
Date	**Resource**	**+/- MW (ICAP)**	**+/- MW (Summer UCAP)**	**+/- MW (Winter UCAP)**	**Summer Position Long/(Short)**	**Winter Position Long/(Short)**
PY 24/25					(72)	(87)
Jul 2025	Ratts Solar	150	55	2	(17)	(86)
May 2026	Existing Bilateral Capacity	(75)	(75)	(75)	(92)	(161)
Jun 2026	New Bilateral Capacity - 5 yr Term	200	200	200	108	39
Jan 2028	Gibson 5 Retirement	(156)	(121)	(106)	(13)	(67)
Jan 2031	IMPA Self Build CT COD	239	201	208	188	141
May 2031	New Bilateral Capacity - 5 Yr Term	(200)	(200)	(200)	(12)	(59)

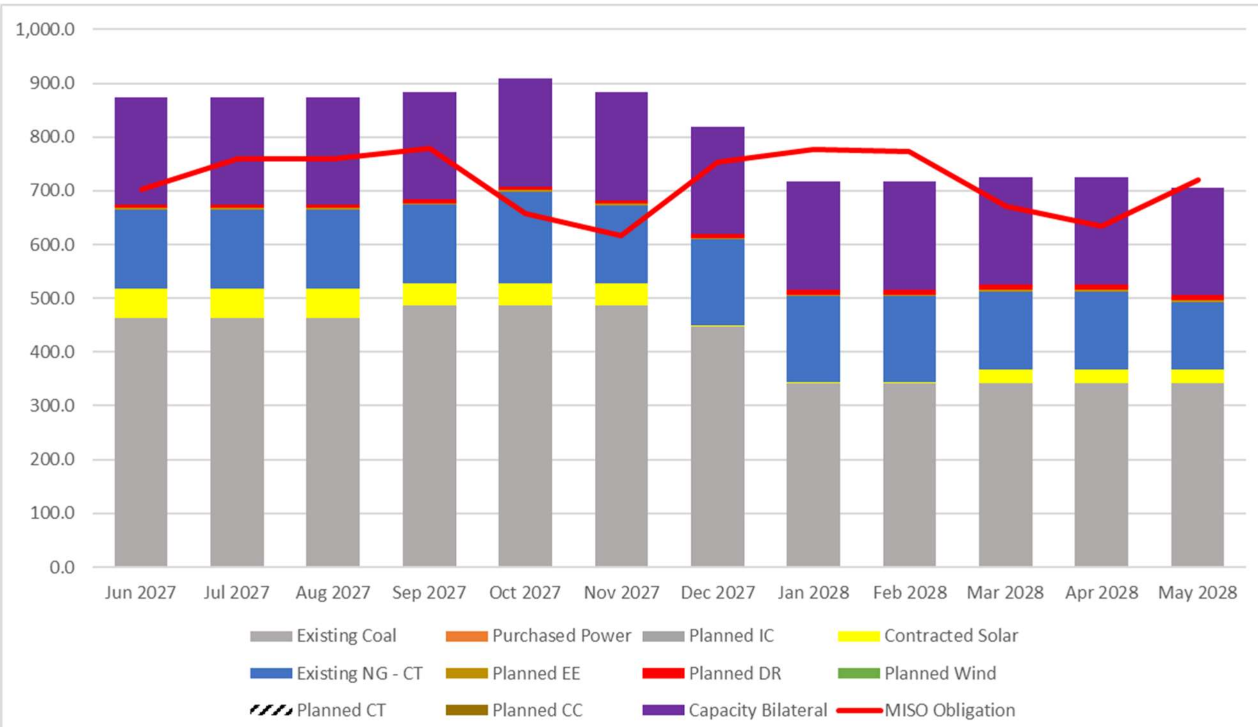
Figure 71 MISO Capacity Position - Planning Year 26-27 – Austerity Case



The addition of the capacity bilateral from the All Source RFP fills a sizeable winter shortfall due to poor winter solar capacity accreditation and further serves to insulate the portfolio from potential future accreditation risk of generating units and increases in planning reserve margins.

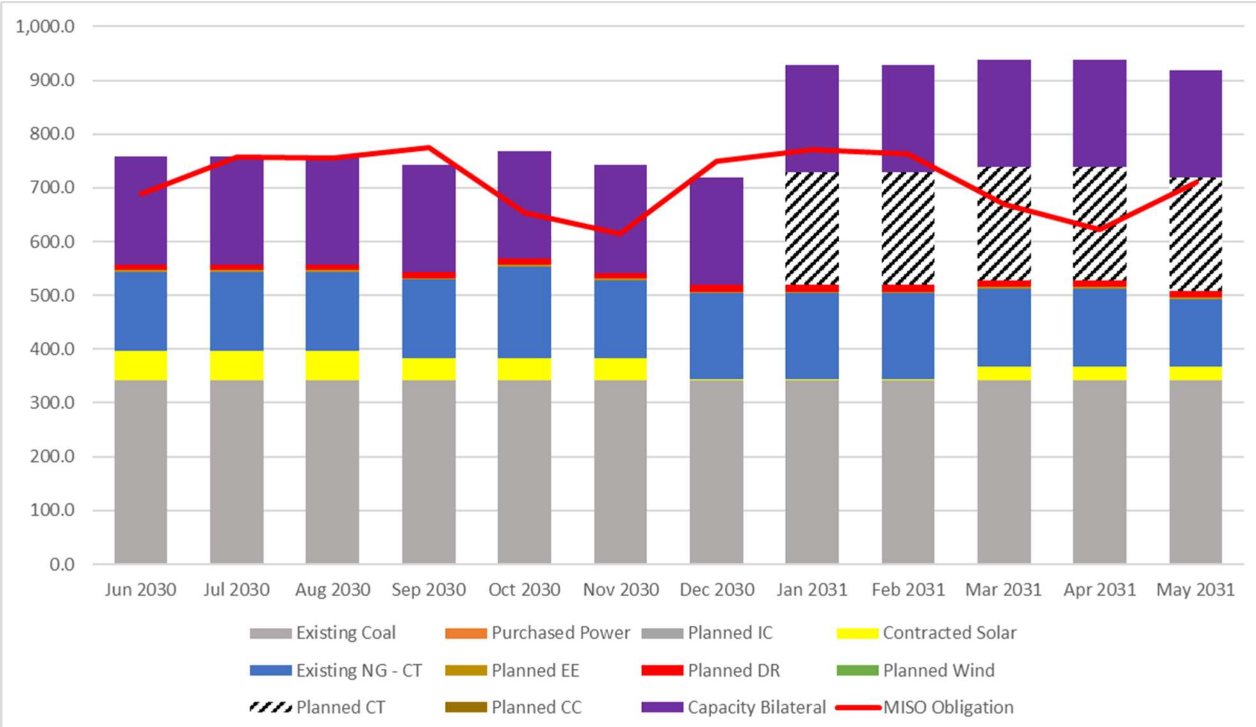
In the following planning year, Gibson is retired on economics and no resources are added to the portfolio, however, the winter short position is mitigated with the capacity bilateral in place.

Figure 72 MISO Capacity Position - Planning Year 27-28 - Austerity Case



There are no portfolio additions until Planning Year 30-31 when a Combustion Turbine is selected. At this point the portfolio is quite long for the first 5 months of the planning year.

Figure 73 MISO Capacity Position - Planning Year 30-31 - Austerity Case

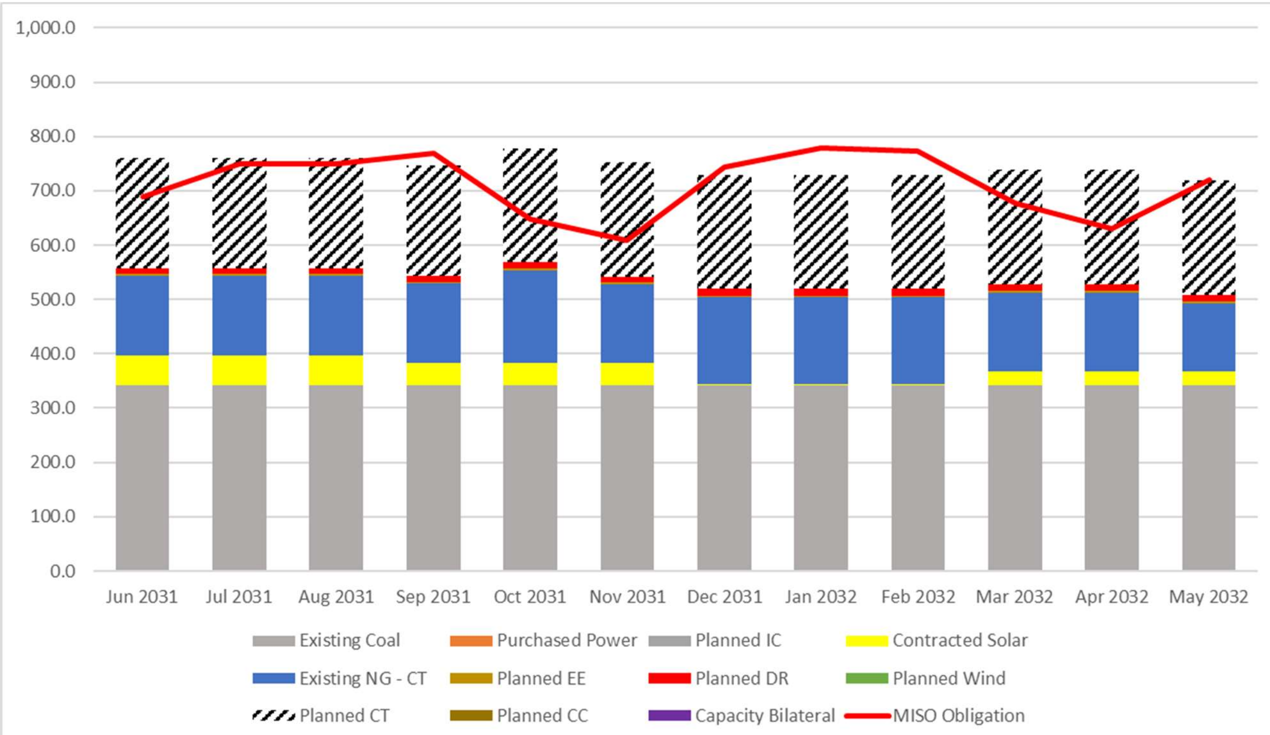


As shown in Figure 73, once the CT is commissioned at the start of the calendar year, the MISO portfolio becomes long capacity from January 2031 to May of 2031.

However, the capacity bilateral would roll off the portfolio beginning in June of the same calendar year, flattening the position.

Figure 74, below, shows the capacity position once the capacity bilateral expires in May 2031.

Figure 74 MISO Capacity Position - Planning Year 31-32 - Austerity Case

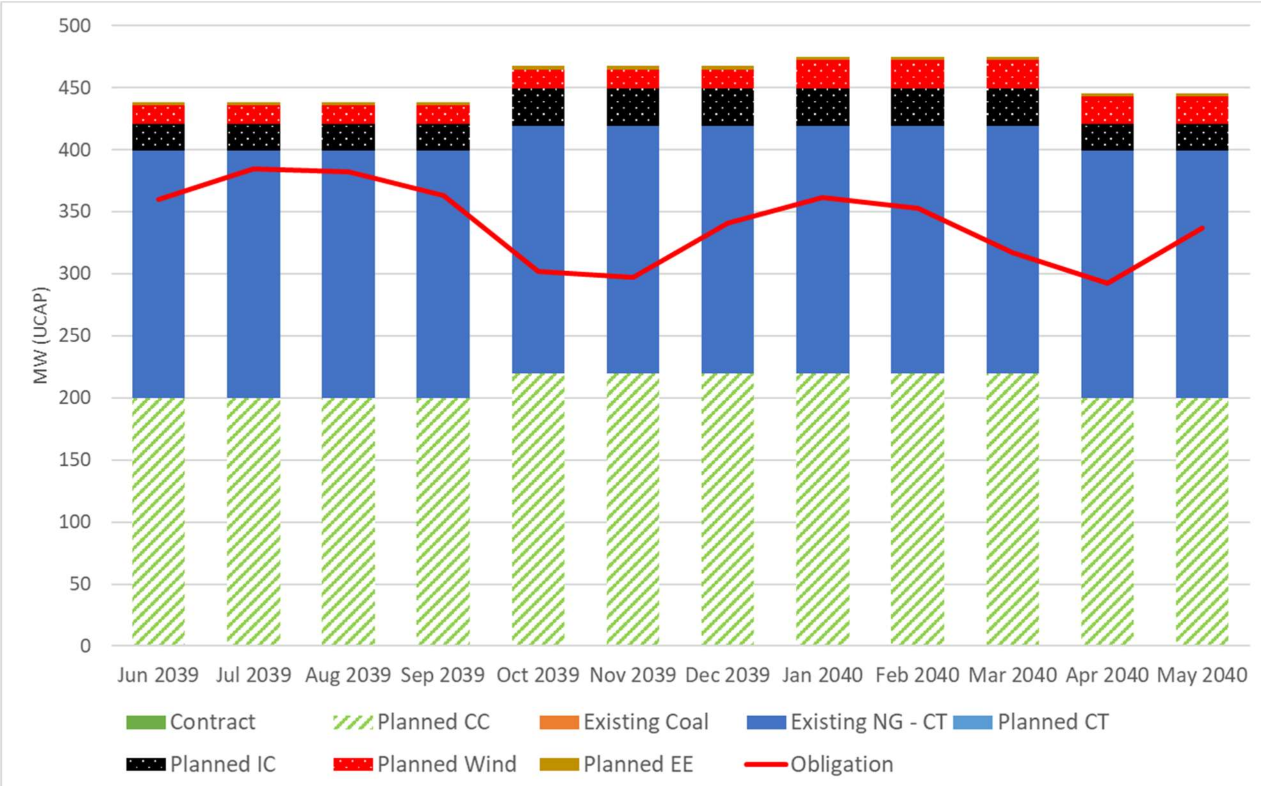


The open position in the winter is very modest, at only 49 MW, which can be hedged in the bilateral markets as market conditions warrant.

14.7.2 PJM Portfolio Discussion

The PJM portfolio has the primary need of replacing the AEP baseload contract that expires in Planning Year 34-35. Given the attractive market implied heat rates under the Austerity case and the lower overall demand picture, the AEP contract is simply replaced with a natural gas combined cycle to complement the existing natural gas combustion turbines. This creates a long capacity position, but the capacity additions are being used to meet energy requirements.

Figure 75 PJM Capacity Position - Planning Year 35-36 - Austerity Case



The PJM portfolio remains fairly static for the duration of the study.

14.8 RISK ASSESSMENT

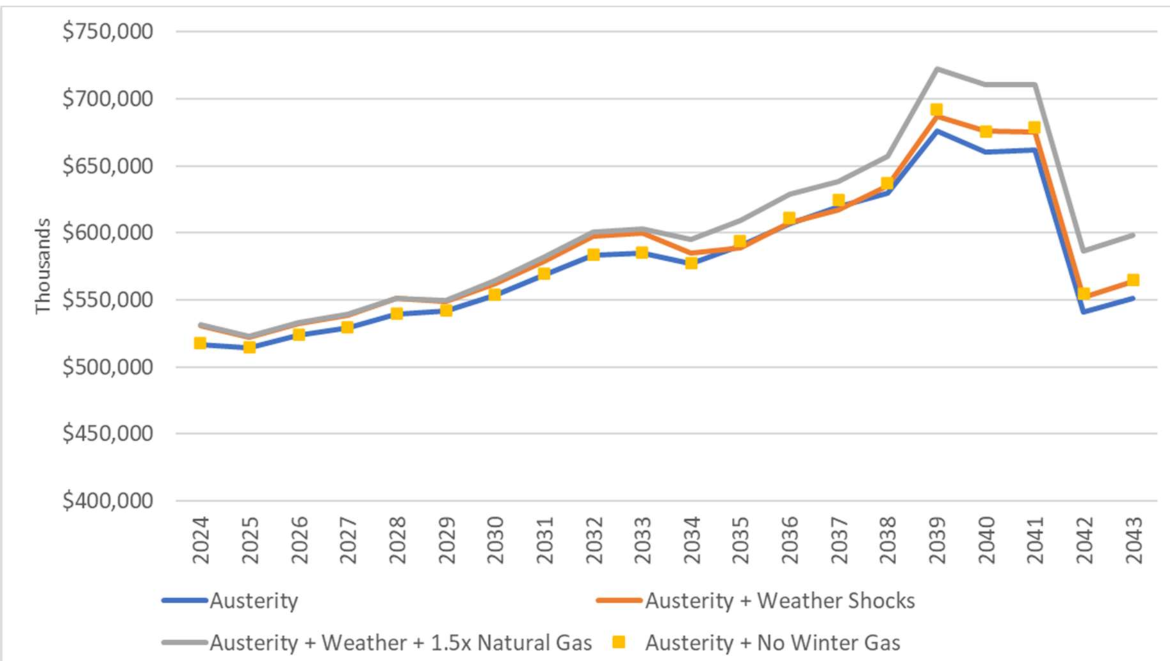
Process

The process for risk assessment for the Austerity Case was the same as was run in the Base Case and Voluntary Net-Zero Case with the selection of winter storm events and recent summer max gen events modeled against the portfolios.

Results

Unsurprisingly, the Austerity case has a larger component of risk than either the Base case or the Voluntary Net Zero case. This is largely due to the natural gas exposure in the portfolio and overall lack of portfolio diversity.

Figure 76 Annual NPVRR Between Cases – Austerity Case



Despite favorable base line market implied heat rates, the biggest risk to the Austerity portfolio is a combination of weather risk and surging natural gas prices.

Table 26 illustrates the NPVRR and rate impacts across the sensitivities.

Table 26 NPVV and Rate Impact Comparisons

Case/Sensitivity	20 Year NPVRR	20 Year Levelized Rate	10 Year NPVRR	10 Year Levelized Rate
Austerity	$6,501	$92.82	$3,987	$89.31
Austerity w No Winter Gas	$6,540	$93.38	$3,991	$89.39
Weather Shock	$6,605	$94.30	$4,064	$91.03
Weather Shock + 1.5X Gas	$6,721	$95.96	$4,075	$91.27

The baseline Austerity Case is very close to the Base Case in terms of rates and revenue requirement, however cracks begin to emerge as the portfolio is stressed. As risk is layered in from "No Winter Gas" to "Weather Shock + 1.5X Gas", the 20-year NPVRR climbs dramatically, and on this metric alone is almost 3 times more sensitive to these shocks than the Base Case.

Section 15 discusses risk impacts across the portfolios in greater detail.

15 THE FIVE PILLARS, PORTFOLIO COMPARISON, AND SELECTION

15.1 THE FIVE PILLARS

The Indiana Utility Regulatory Commission's (IURC) General Administrative Order 2023-04 requires utilities to specifically discuss "Five Pillars" when preparing an IRP.

These Five Pillars are: Reliability, Resilience, Stability, Affordability, and Environmental Sustainability. Reliability refers to the concepts of resource adequacy and operational dependability. Resilience refers to the ability of supply to adapt to changing conditions (e.g., weather). Stability refers to the ability of system to maintain frequency or equilibrium. The final two, affordability and environmental sustainability, are more self-explanatory.

Of these Five Pillars, IMPA's own mission statement contains three of the Five Pillars: reliability, affordability, and environmental sustainability. [29]

Quantifying these metrics in terms of model outputs is somewhat of a challenge as most planning models do not capture certain metrics like frequency response. Nevertheless, IMPA examined several outputs available from Encompass and ultimately selected eight metrics to capture the Five Pillars as best as possible.

[29] https://www.impa.com/

Table 27 IMPA Portfolio Metrics & The Five Pillars

Metric	*Pillar Addressed (Reliability, Affordability, Resiliency, Stability, Environmental Sustainability)*
20 Yr Portfolio CO2 Emissions - 000,000 tons	Environmental Sustainability
Market Energy as % of Load	Reliability/Resiliency
Market Capacity as % of Obligation (worst month)	Reliability/Resiliency
Potential Unserved Energy (MWh)	Reliability/Resiliency
10 Year Levelized Rate	Affordability
20 Year Levelized Rate	Affordability
% Ramp Capable Generation (Up & Down) 2030	Reliability/Resiliency & Stability
% Ramp Capable Generation (Up & Down) 2040	Reliability/Resiliency & Stability

With these criteria selected, a weighted scoring system was then devised to rank each portfolio and scenario run.

In assigning weights to the metrics in Table 27, IMPA focused first on metrics contained in its own mission statement. The first metric is Total CO2 emissions over the 20-year study horizon. IMPA assigned this a 30% weight due to being contained in the IMPA mission statement. The second metric is market energy as a percent of load. This metric was assigned a 5% weight, which is relatively low. This low weight is due to the fact that all the portfolios had constraints on how much reliance could be placed on the market for energy requirements. This led to very minor differences between the three main cases run. The third metric is market capacity as a percentage of the overall obligation. This metric received a 10% weight due to IMPA deeming the capacity position to be more important overall than energy given the difficulty of either building new capacity or contracting for capacity. The fourth metric is potential unserved energy (EUE). Generally, in any optimization this number should be zero, however this gives IMPA a reliability metric to evaluate risk in portfolios that are run outside their initial assumed conditions. EUE that does materialize in these runs is an artifact of limits on how much the portfolios can interact with the market, resource adequacy and unforeseen shocks to load. This metric was given a 5% weight, largely due to the fact that under optimized conditions, portfolios should have zero hours of EUE.

The next two metrics are heavily weighted and pertain to affordability metrics. These are the 10 year and 20 year levelized rates, which get a 30% and 10% weighting, respectively. The primary reason the 10-year rate gets a much higher emphasis is largely due to better visibility on future prices over that time frame, versus the back half of the study, which relies heavily on various market forecasts and assumptions that shape energy prices (e.g., the percent of MISO that is renewable energy in 2040). Furthermore, a shorter time horizon on rate projection allows IMPA some degree of course correcting between IRP cycles and planning cycles.

The final two metrics are the percent of the portfolio that has bilateral ramp capable generation by 2030 and 2040. These get 5% weights each with the low weight stemming from the fact that frequency control on the grid is largely the responsibility of the grid operator. However, that does not give market participants a pass on not having sources of generation that can provide voltage control under all conditions.

Table 28 - Portfolio Metrics and Weights

Metric	*Pillar Addressed (Reliability, Affordability, Resiliency, Stability, Environmental Sustainability)*	*Weight*
20 Yr Portfolio CO2 Emissions - 000,000 tons	Environmental Sustainability	30%
Market Energy as % of Load	Reliability/Resiliency	5%
Market Capacity as % of Obligation (worst month)	Reliability/Resiliency	10%
Potential Unserved Energy (MWh)	Reliability/Resiliency	5%
10 Year Levelized Rate	Affordability	30%
20 Year Levelized Rate	Affordability	10%
% Ramp Capable Generation (Up & Down) 2030	Reliability/Resiliency & Stability	5%
% Ramp Capable Generation (Up & Down) 2040	Reliability/Resiliency & Stability	5%
		100%

The first set of portfolios ranked are the three main cases against one another. These cases are the Base, Voluntary Net Zero, and Austerity Cases. Since this is essentially a three-way race, each portfolio is scored on each metric relative to its peer with points being assigned for 1st, 2nd, and 3rd. 1st place in a category is assigned 100 points, 2nd receives 66 points, and 3rd gets 33 points. These points are then weighed and summed to arrive at a total portfolio score. Table 29 illustrates the weighted points across categories and the resulting tally for each portfolio.

Table 29 Initial Portfolio Rankings

Pillar/Metric	*Base*	*Austerity*	*Voluntary Net Zero*
20 Yr Portfolio CO2 Emissions - 000,000 tons	20	10	30
Market Energy as % of Load	2	5	3
Market Capacity as % of Obligation (worst month)	7	10	3
Potential Unserved Energy (MWh)	5	5	5
10 Year Levelized Rate	30	20	10
20 Year Levelized Rate	10	7	3
% Ramp Capable Generation (Up & Down) 2030	3	5	2
% Ramp Capable Generation (Up & Down) 2040	3	5	2
Total Points	**80**	**66**	**58**

The next step was to evaluate the three core portfolios across risk shocks. In many of the risk scenarios the fundamental portfolio characteristics do not change enough to impact portfolio relative rankings, however, it is notable that under weather shocks, the Austerity portfolio experienced an EUE event (roughly 16,000 MWh) due to the higher loads in the weather shock sensitivity.

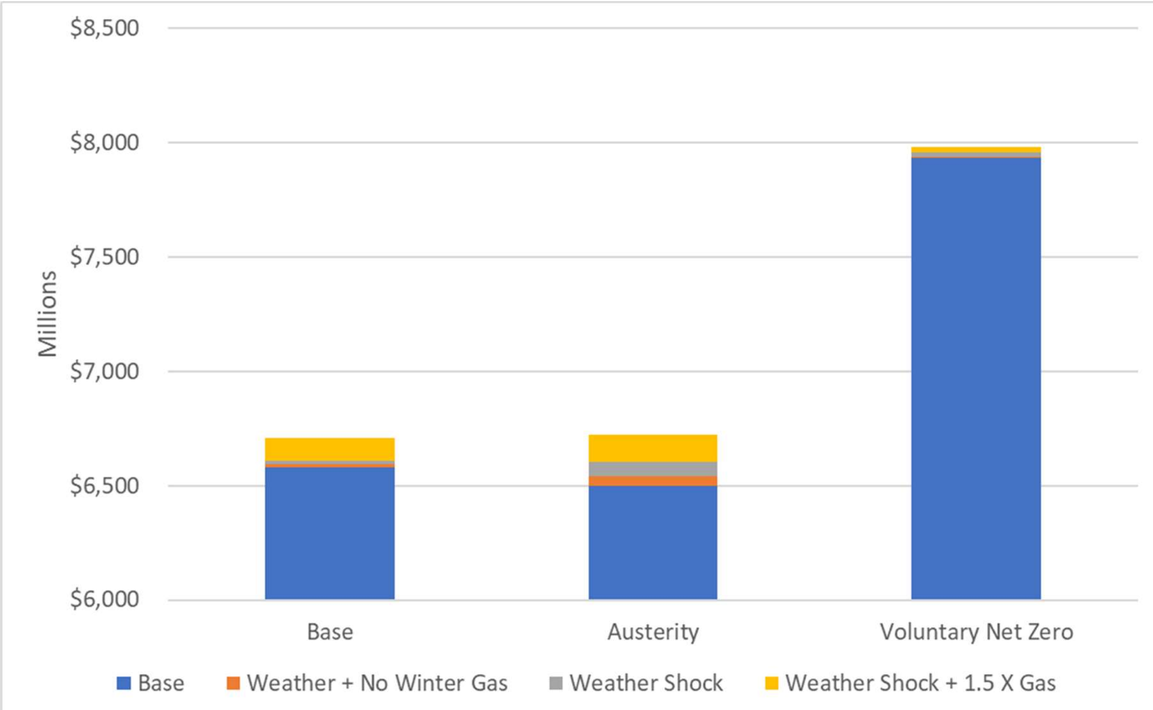
Table 30 Portfolio Rankings - Weather Shock

Pillar/Metric	***Base***	***Austerity***	***Voluntary Net Zero***
20 Yr Portfolio CO2 Emissions - 000,000 tons	20	10	30
Market Energy as % of Load	2	5	3
Market Capacity as % of Obligation (worst month)	7	10	3
Potential Unserved Energy (MWh)	5	2	5
10 Year Levelized Rate	30	20	10
20 Year Levelized Rate	10	7	3
% Ramp Capable Generation (Up & Down) 2030	3	5	2
% Ramp Capable Generation (Up & Down) 2040	3	5	2
Total Points	**80**	**63**	**58**

Whereas each portfolio was initially "tied" across the EUE metric, the Austerity Case, when placed under duress, loses three points on the overall score. While this does not change the overall rankings, it does highlight a weakness in the Austerity Case build plan.

Ignoring the potential "cost" of EUE, stacking the cumulative impacts of risk across the portfolios, and portraying them graphically is helpful, despite the fact they are not truly cumulative. In Figure 77 on the following page, the Austerity case carries a slightly lower NPVRR over 20 years than the Base or Voluntary Net Zero Cases (but a slightly higher rate due to lower forecasted loads). However, the lower overall revenue requirement comes at a cost of increased risk in the Austerity Case relative to the other two plans.

Figure 77 - 20 Year NPVV and Risk



15.2 Cross Scenario Analysis

In order to quantify robustness of build plans, IMPA then modeled each build plan in the other build plans' worlds or underlying set of assumptions. For example, the optimized build plan for the Base Case was modeled against the underlying set of assumptions used in the Voluntary Net Zero Case. This is done such that each portfolio is then challenged against a set of assumptions it was not optimized around.

For portfolios mapped to the Voluntary Net Zero Case, the implied abatement cost for CO2 from the Voluntary Net Zero Case was applied to that portfolio's respective CO2 emissions to avoid conferring a "free option" to those portfolios.

Table 31 shows the weighted points across these scenarios. "No CO2" refers to the Voluntary Net Zero Case in the table.

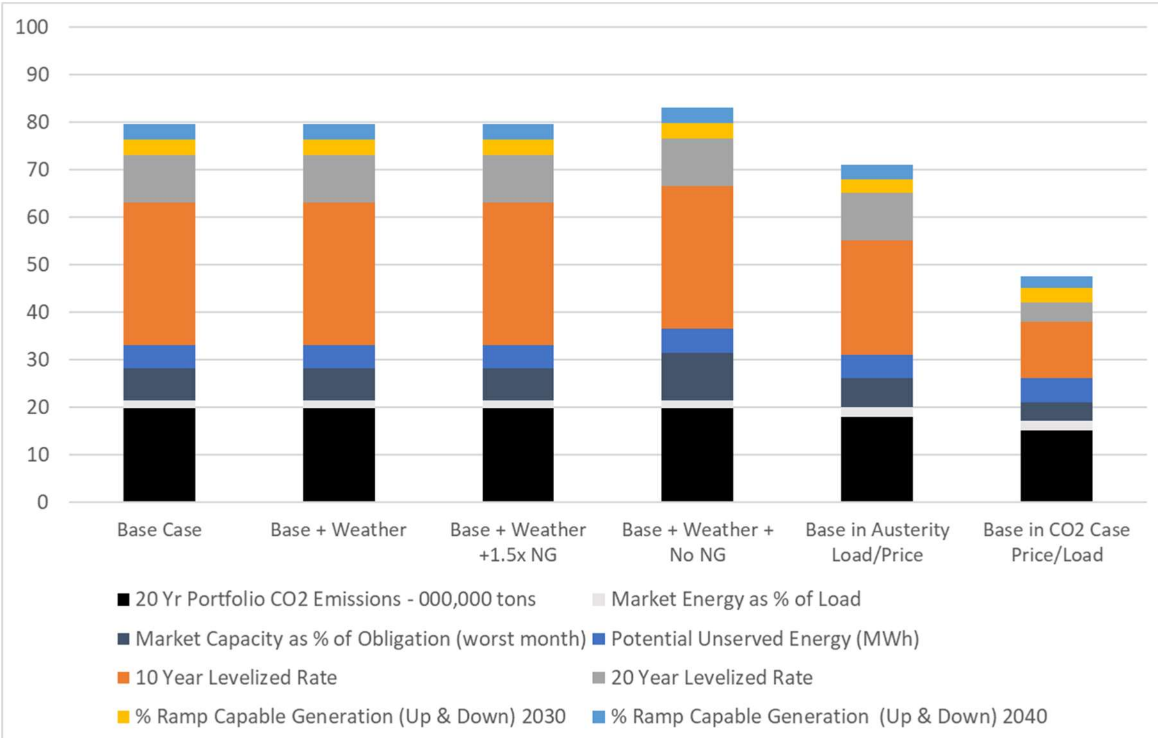
Table 31 Portfolio Scoring Across Cases

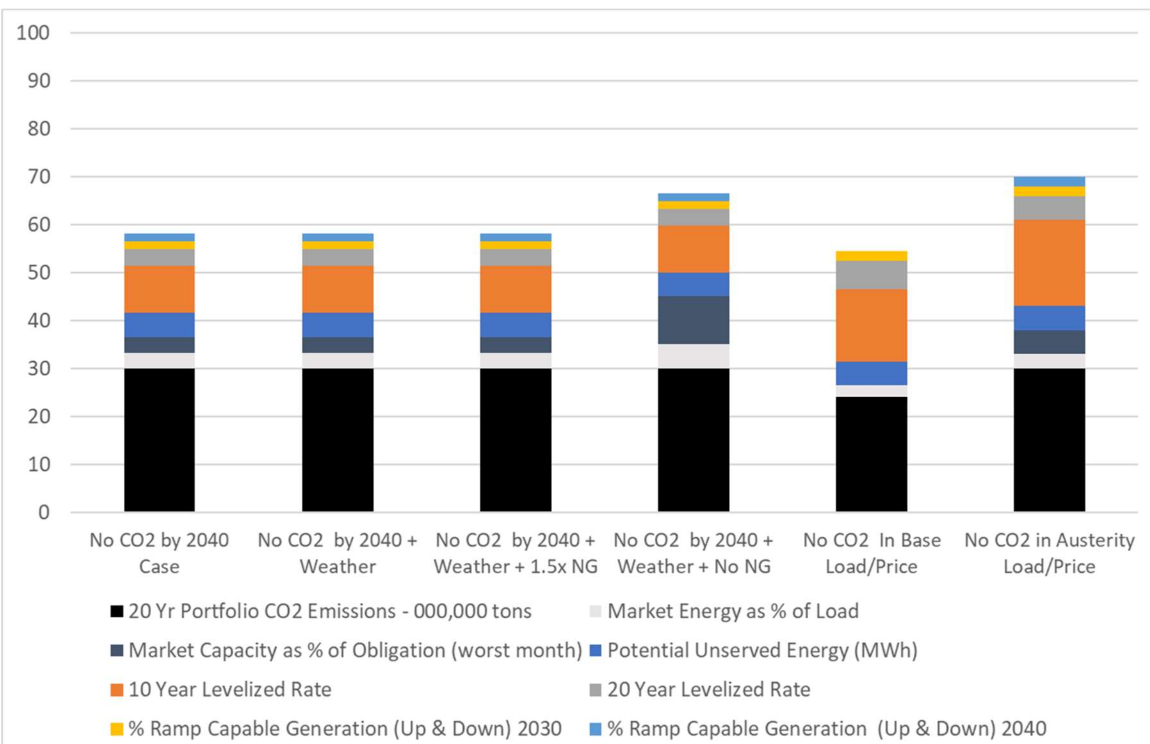
Pillar/Metric	*Base in Austerity Load/Price*	*Base in No CO2 Load/Price*	*Austerity in Base Load/Price*	*Austerity in No CO2 Load/Price*	*No CO2 In Base Load/Price*	*No CO2 in Austerity Load/Price*
20 Yr Portfolio CO2 Emissions - 000,000 tons	18	15	12	0	24	30
Market Energy as % of Load	2	2	5	5	2.5	3
Market Capacity as % of Obligation (worst month)	6	4	10	10	0	5
Potential Unserved Energy (MWh)	5	5	2	0	5	5
10 Year Levelized Rate	24	12	30	0	15	18
20 Year Levelized Rate	10	4	8	0	6	5
% Ramp Capable Generation (Up & Down) 2030	3	3	5	5	2	2
% Ramp Capable Generation (Up & Down) 2040	3	2.5	5	5	0	2
Total Points	**71**	**48**	**77**	**25**	**55**	**70**

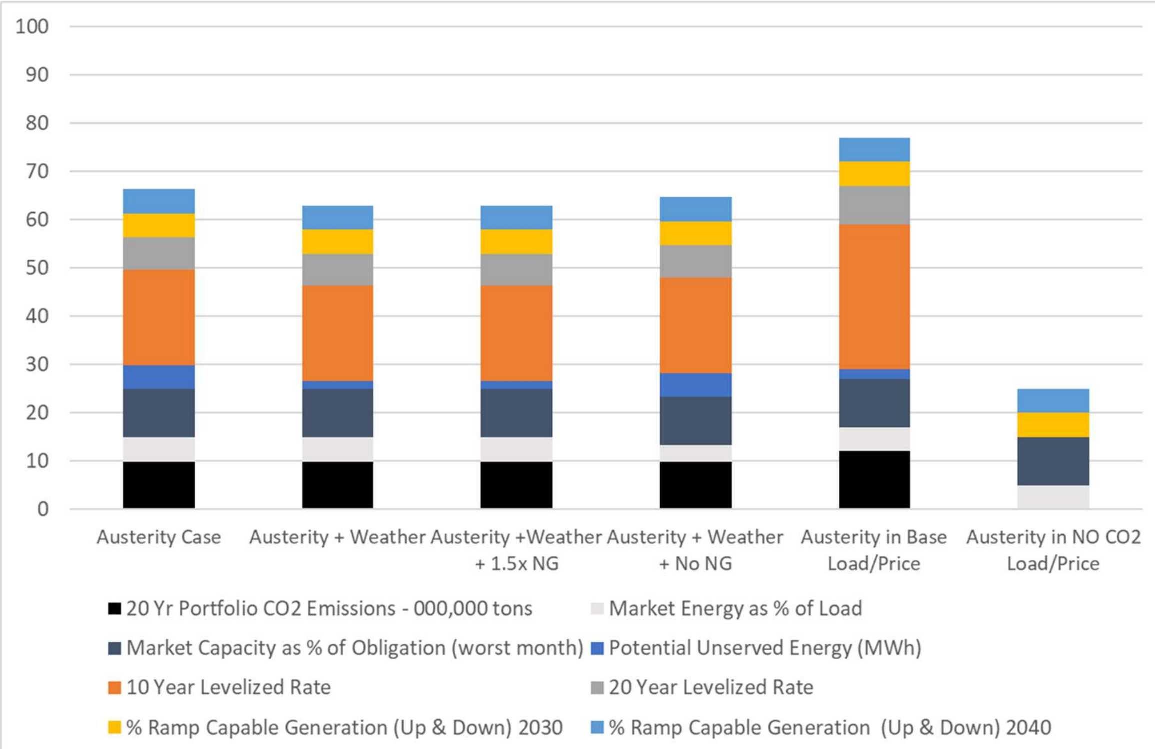
As shown above, the Base build plan and the Austerity build plan in the Voluntary Net Zero Case score poorly relative to the Voluntary Net Zero build in the Base and Austerity Cases. The Base build plan holds up better than the Austerity build plan under the Voluntary Net Zero assumptions while the Base build plan outperforms the Voluntary Net Zero build in the Base Case assumptions.

Weighted scoring for each scored portfolio/scenario is shown graphically in Figure 78.

Figure 78 Portfolio Scoring







The table on the following page illustrates the component scoring and final weighted score of each portfolio. The weighted average score weights of the first 4 Cases/Scenarios at 40% (10% each) and the remaining two scenarios at 60% (30% each). The reasons for this weighting in the final scoring is to avoid over weighting the underlying case and to place more importance on how the underlying case performed in alternate worlds/settings.

Table 32 - Portfolio Scoring Summary

Pillar/Metric	*Base Case*	*Base + Weather*	*Base + Weather +1.5x NG*	*Base + Weather + No NG*	*Base in Austerity Load/Price*	*Base in CO2 Case Price/Load*	*Weighted Average*
20 Yr Portfolio CO2 Emissions - 000,000 tons	20	20	20	20	18	15	18
Market Energy as % of Load	2	2	2	2	2	2	2
Market Capacity as % of Obligation (worst month)	7	7	7	10	6	4	6
Potential Unserved Energy (MWh)	5	5	5	5	5	5	5
10 Year Levelized Rate	30	30	30	30	24	12	23
20 Year Levelized Rate	10	10	10	10	10	4	8
% Ramp Capable Generation (Up & Down) 2030	3	3	3	3	3	3	3
% Ramp Capable Generation (Up & Down) 2040	3	3	3	3	3	3	3
Total Base Portfolio Points	**80**	**80**	**80**	**83**	**71**	**48**	**68**

Pillar/Metric	*No CO2 by 2040 Case*	*No CO2 by 2040 + Weather*	*No CO2 by 2040 + Weather + 1.5x NG*	*No CO2 by 2040 + Weather + No NG*	*No CO2 In Base Load/Price*	*No CO2 in Austerity Load/Price*	*Weighted Average*
20 Yr Portfolio CO2 Emissions - 000,000 tons	30	30	30	30	24	30	28
Market Energy as % of Load	3	3	3	5	3	3	3
Market Capacity as % of Obligation (worst month)	3	3	3	10	0	5	3
Potential Unserved Energy (MWh)	5	5	5	5	5	5	5
10 Year Levelized Rate	10	10	10	10	15	18	14
20 Year Levelized Rate	3	3	3	3	6	5	5
% Ramp Capable Generation (Up & Down) 2030	2	2	2	2	2	2	2
% Ramp Capable Generation (Up & Down) 2040	2	2	2	2	0	2	1
Total No CO2 Portfolio Points	**58**	**58**	**58**	**67**	**55**	**70**	**61**

Pillar/Metric	*Austerity Case*	*Austerity + Weather*	*Austerity +Weather + 1.5x NG*	*Austerity + Weather + No NG*	*Austerity in Base Load/Price*	*Austerity in NO CO2 Load/Price*	*Weighted Average*
20 Yr Portfolio CO2 Emissions - 000,000 tons	10	10	10	10	12	0	8
Market Energy as % of Load	5	5	5	3	5	5	5
Market Capacity as % of Obligation (worst month)	10	10	10	10	10	10	10
Potential Unserved Energy (MWh)	5	2	2	5	2	0	2
10 Year Levelized Rate	20	20	20	20	30	0	17
20 Year Levelized Rate	7	7	7	7	8	0	5
% Ramp Capable Generation (Up & Down) 2030	5	5	5	5	5	5	5
% Ramp Capable Generation (Up & Down) 2040	5	5	5	5	5	5	5
Total Austerity Case Portfolio Points	**66**	**63**	**63**	**65**	**77**	**25**	**56**

Across all rankings, the Base Case build plan outperforms the other build plans with a weighted average score across the gamut of 68, while the Voluntary Net Zero Case scores an average of 61 of 2nd, and the Austerity at a close 3rd place with 56.

With this scoring, the Base Case build plan becomes the basis for the preferred portfolio and drives the short-term action plan. The following tables show IMPA's summer and winter capacity additions and retirements within the preferred portfolio.

Table 33 Preferred Portfolio Capacity by Planning Year - Summer (UCAP)

Resource Type/Year	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***
Existing Coal	536.1	536.1	536.1	536.1	415.0	342.1	342.1	342.1	342.1	342.1
Purchased Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Planned IC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.0
Contracted Solar	0.0	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5
Existing NG - CT	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1
Planned EE	2.2	3.2	4.3	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Planned DR	0.0	2.1	4.3	6.4	8.6	10.7	0.0	10.7	10.7	10.7
Planned Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Planned CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	201.0	201.0	201.0
Planned CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Capacity Purchase	75.0	75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Planned Solar	0.0	0.0	0.0	0.0	0.0	18.5	37.0	55.5	74.0	92.5
Capacity Bilateral	0.0	0.0	200.0	200.0	200.0	200.0	200.0	0.0	0.0	0.0
Contract	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0
Total Resources	1,149.4	1,208.0	1,336.3	1,339.5	1,220.6	1,168.3	1,176.1	1,206.3	1,224.8	1,264.3
Total Obligation	1,040.8	1,038.6	1,110.4	1,111.8	1,118.0	1,129.3	1,128.3	1,130.1	1,130.7	1,138.4

Resource Type/Year	***11***	***12***	***13***	***14***	***15***	***16***	***17***	***18***	***19***	***20***
Existing Coal	342.1	342.1	342.1	342.1	342.1	156.0	156.0	156.0	156.0	156.0
Purchased Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Planned IC	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Contracted Solar	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5
Existing NG - CT	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1
Planned EE	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Planned DR	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7
Planned Wind	22.5	22.5	45.0	45.0	52.5	52.5	60.0	60.0	60.0	60.0
Planned CT	201.0	201.0	201.0	201.0	201.0	201.0	201.0	201.0	201.0	201.0
Planned CC	100.0	100.0	100.0	100.0	200.0	300.0	300.0	300.0	300.0	300.0
Existing Capacity Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Planned Solar	111.0	129.5	129.5	129.5	129.5	129.5	129.5	129.5	129.5	129.5
Capacity Bilateral	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Contract	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Resources	1,215.3	1,233.8	1,256.3	1,256.3	1,363.8	1,277.7	1,285.2	1,285.2	1,285.2	1,285.2
Total Obligation	1,165.5	1,168.2	1,167.8	1,171.1	1,176.3	1,185.9	1,188.8	1,188.1	1,192.6	1,196.6

Table 34 Preferred Portfolio Capacity by Planning Year - Winter (UCAP)

Resource Type/Year	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***
Existing Coal	520.9	520.9	520.9	415.0	342.1	342.1	342.1	342.1	342.1	342.1
Purchased Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Planned IC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0	30.0
Contracted Solar	0.0	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Existing NG - CT	359.3	359.3	359.3	359.3	359.3	359.3	359.3	359.3	359.3	359.3
Planned EE	3.5	4.7	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Planned DR	2.5	5.0	7.5	10.0	12.6	0.0	12.6	12.6	12.6	12.6
Planned Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.5
Planned CT	0.0	0.0	0.0	0.0	0.0	0.0	208.0	208.0	208.0	208.0
Planned CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	110.0
Existing Capacity Purch	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Planned Solar	0.0	0.0	0.0	0.0	0.5	1.0	1.5	2.0	2.5	3.0
Capacity Bilateral	0.0	0.0	200.0	200.0	200.0	200.0	200.0	0.0	0.0	0.0
Contract	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0
Total Resources	1,076.2	1,081.4	1,285.0	1,181.6	1,111.8	1,099.7	1,320.8	1,121.3	1,151.8	1,284.8
Total Obligation	1,046.9	1,046.4	1,121.9	1,123.3	1,133.3	1,139.7	1,139.7	1,141.0	1,142.9	1,144.8

Resource Type/Year	***11***	***12***	***13***	***14***	***15***	***16***	***17***	***18***	***19***	***20***
Existing Coal	342.1	342.1	342.1	342.1	156.0	156.0	156.0	156.0	156.0	156.0
Purchased Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Planned IC	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Contracted Solar	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Existing NG - CT	359.3	359.3	359.3	359.3	359.3	359.3	359.3	359.3	359.3	359.3
Planned EE	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Planned DR	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6
Planned Wind	22.5	45.0	45.0	52.5	52.5	60.0	60.0	60.0	60.0	60.0
Planned CT	208.0	208.0	208.0	208.0	208.0	208.0	208.0	208.0	208.0	208.0
Planned CC	110.0	110.0	110.0	220.0	330.0	330.0	330.0	330.0	330.0	330.0
Existing Capacity Purch	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Planned Solar	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Capacity Bilateral	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Contract	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Resources	1,095.3	1,117.8	1,117.8	1,235.3	1,159.2	1,166.7	1,166.7	1,166.7	1,166.7	1,166.7
Total Obligation	1,171.5	1,179.3	1,180.5	1,184.6	1,187.9	1,190.9	1,198.6	1,201.2	1,205.5	1,210.4

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16 SHORT TERM ACTION PLAN

16.1 ACTION (S) REQUIRED TO IMPLEMENT THE PLAN

IMPA is currently working with the other joint owners of Gibson 5 to a mutually agreeable retirement date for Gibson 5. In IMPA's portfolio modeling, IMPA assumed some additional capital spend to extend the life of Gibson 5, but then allowed the model to retire Gibson based on economics. In 2 of the 3 cases, Gibson was retired in 2028. Early discussions between owners suggest the actual retirement date may occur in the 2029 or 2030 timeframe. Based on portfolio scoring, the Base Case build plan is the preferred portfolio and drives the short term action plan.

Action Plan Items

1. Work with the Gibson 5 partners regarding the final plan, timing and cost for retirement of the unit.
2. Begin internal planning for the best path forward for adding CT capacity to its portfolio as a replacement for Gibson 5.
3. Execute 200 MW capacity bilateral contract.
4. Maintain regular contact with the marketplace for both financial and physical power.
5. Maintain regular contact with the renewable energy market to evaluate potential utility scale projects that may benefit the power supply portfolio.
6. Continue the IMPA Energy Efficiency Program and implement revised demand response program.
7. Continue to utilize the RTO/ISO stakeholder process to monitor market rules regarding renewable capacity accreditation and resource adequacy.
8. Monitor elections and the legislative process to remain informed on future environmental policy as it pertains to CO_2.
9. Continue to enhance IMPA's modeling capabilities with respect to transmission, capacity/market price formation, and portfolio optimization.

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17 APPENDIX

A. Hourly System Loads
B. Historic System Load Shapes
C. C1 - Hourly Market Prices – Indiana Hub
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D. D1 - Existing Resource Data – Summary
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F. Avoided Costs
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